El Paso Electric

P.O. Box 982
El Paso, Texas
79960-0982
(915) 543-5711

June 10, 2021

New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez Suite 1
Santa Fe, NM 87505-1816

Re: Application for Renewal of Title V Operating Permit P127-R3
El Paso Electric Company – Rio Grande Generating Station

Dear Air Quality Bureau:

The El Paso Electric Company (EPE) owns and operates the Rio Grande Generating Station located in the city of Sunland Park in Doña Ana County, New Mexico. EPE currently operates three natural gas-fired boilers, one natural gas-fired turbine, and ancillary equipment (cooling towers and piping) under New Mexico Operating Permit No. P127R3 and Acid Rain Permit P127AR3. Please let this letter and the attached serve as EPE's request to renew the above-referenced air permit, under 20 NMAC 2.70.300.B.2. Please note that although the issuance of the permit is dated as March 29, 2017 on the current permit's cover page, the expiration date on said cover page was stamped November 29, 2022 along with an application due date of November 29, 2021. NMED AQB has acknowledged this discrepancy and EPE looks forward to working with the AQB to get the permit renewed before the original March 29, 2022 expiration date as previously assured by AQB staff.

Enclosed are two hard copies of the full Title V renewal application package (the original and a photocopy) and two disks containing the digital versions.

Thank you in advance for your assistance. If you have any questions or comments about the information presented in this application, please do not hesitate to contact me at (915) 543-4166 or at Daniel.Perez@epelectric.com.

Sincerely,
EL PASO ELECTRIC COMPANY

Daniel G. Perez,
Supervisor- Environmental Compliance

Mail Application To:		For Department use only:
New Mexico Environment Department Air Quality Bureau Permits Section 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone: (505) 476-4300 Fax: (505) 476-4375 www.env.nm.gov/aqb		AIRS No.:

Universal Air Quality Permit Application

Use this application for NOI, NSR, or Title V sources.

Use this application for: the initial application, modifications, technical revisions, and renewals. For technical revisions, complete Sections, 1-A, 1-B, 2-E, 3, 9 and any other sections that are relevant to the requested action; coordination with the Air Quality Bureau permit staff prior to submittal is encouraged to clarify submittal requirements and to determine if more or less than these sections of the application are needed. Use this application for streamline permits as well. See Section 1-I for submittal instructions for other permits.

This application is submitted as (check all that apply)**:** ☐ Request for a No Permit Required Determination (no fee)
☐ **Updating** an application currently under NMED review. Include this page and all pages that are being updated (no fee required).
Construction Status: ☐ Not Constructed ☐ Existing Permitted (or NOI) Facility ☐ Existing Non-permitted (or NOI) Facility
Minor Source: ☐ a NOI 20.2.73 NMAC ☐ 20.2.72 NMAC application or revision ☐ 20.2.72.300 NMAC Streamline application
Title V Source: ☐ Title V (new) ☒ Title V renewal ☐ TV minor mod. ☐ TV significant mod. TV Acid Rain: ☐ New ☒ Renewal
PSD Major Source: ☐ PSD major source (new) ☐ minor modification to a PSD source ☐ a PSD major modification

Acknowledgements:
☒ I acknowledge that a pre-application meeting is available to me upon request. ☒ Title V Operating, Title IV Acid Rain, and NPR applications have no fees.
☐ $500 NSR application Filing Fee enclosed OR ☐ The full permit fee associated with 10 fee points (required w/ streamline applications).
☐ Check No.: in the amount of
☒ I acknowledge the required submittal format for the hard copy application is printed double sided 'head-to-toe', 2-hole punched (except the Sect. 2 landscape tables is printed 'head-to-head'), numbered tab separators. Incl. a copy of the check on a separate page.
☒ I acknowledge there is an annual fee for permits in addition to the permit review fee: www.env.nm.gov/air-quality/permit-fees-2/.
☐ This facility qualifies for the small business fee reduction per 20.2.75.11.C. NMAC. The full $500.00 filing fee is included with this application and I understand the fee reduction will be calculated in the balance due invoice. The Small Business Certification Form has been previously submitted or is included with this application. (Small Business Environmental Assistance Program Information: www.env.nm.gov/air-quality/small-biz-eap-2/.)

Citation: Please provide the **low level citation** under which this application is being submitted: **20.2.70.300.B(2) NMAC**
(e.g. application for a new minor source would be 20.2.72.200.A NMAC, one example for a Technical Permit Revision is 20.2.72.219.B.1.b NMAC, a Title V acid rain application would be: 20.2.70.200.C NMAC)

Section 1 – Facility Information

Section 1-A: Company Information

		AI # if known (see 1st 3 to 5 #s of permit IDEA ID No.): 122	Updating Permit/NOI #: P127-R3
1	Facility Name: Rio Grande Generating Station	Plant primary SIC Code (4 digits): 4911	
		Plant NAIC code (6 digits): 221112	
a	Facility Street Address (If no facility street address, provide directions from a prominent landmark): 3501 Doniphan Road, Sunland Park, NM 88063		
2	Plant Operator Company Name: El Paso Electric Company	Phone/Fax: (915) 543-5711 / (915) 543-5802	
a	Plant Operator Address: 100 North Stanton Street, El Paso, Texas 79901		

b	Plant Operator's New Mexico Corporate ID or Tax ID: 74-0607870	
3	Plant Owner(s) name(s): El Paso Electric Company	Phone/Fax: (915) 543-5711 / (915) 543-5802
a	Plant Owner(s) Mailing Address(s): 100 North Stanton Street, El Paso, Texas 79901	
4	Bill To (Company): El Paso Electric Company	Phone/Fax: (915) 543-5711 / (915) 543-5802
a	Mailing Address: 100 North Stanton Street, El Paso, Texas 79901	E-mail: celena.arreola@epelectric.com
5	☒ Preparer: ☐ Consultant: Teresa M. Sosa	Phone/Fax: (915) 521-4649 / (915) 543-5802
a	Mailing Address: P.O. Box 982, El Paso, Texas 79960	E-mail: teresa.sosa@epelectric.com
6	Plant Operator Contact: John D. Aranda	Phone/Fax: (915) 543-2959 / (915) 543-5802
a	Address: 3501 Doniphan Road, Sunland Park, New Mexico 88063	E-mail: david.aranda@epelectric.com
7	Air Permit Contact: Daniel Perez	Title: Environmental Compliance Supervisor
a	E-mail: daniel.perez@epelectric.com	Phone/Fax: (915) 543-4166 / (915) 543-5802
b	Mailing Address: P.O. Box 982, El Paso, Texas 79960	
c	The designated Air permit Contact will receive all official correspondence (i.e. letters, permits) from the Air Quality Bureau.	

Section 1-B: Current Facility Status

1.a	Has this facility already been constructed? ☒ Yes ☐ No	1.b If yes to question 1.a, is it currently operating in New Mexico? ☒Yes ☐ No
2	If yes to question 1.a, was the existing facility subject to a Notice of Intent (NOI) (20.2.73 NMAC) before submittal of this application? ☐ Yes ☒ No	If yes to question 1.a, was the existing facility subject to a construction permit (20.2.72 NMAC) before submittal of this application? ☒ Yes ☐ No
3	Is the facility currently shut down? ☐ Yes ☒ No	If yes, give month and year of shut down (MM/YY):
4	Was this facility constructed before 8/31/1972 and continuously operated since 1972? ☒ Yes ☐ No	
5	If Yes to question 3, has this facility been modified (see 20.2.72.7.P NMAC) or the capacity increased since 8/31/1972? ☐Yes ☐No ☒ N/A	
6	Does this facility have a Title V operating permit (20.2.70 NMAC)? ☒ Yes ☐ No	If yes, the permit No. is: P-127-R3
7	Has this facility been issued a No Permit Required (NPR)? ☐ Yes ☒ No	If yes, the NPR No. is:
8	Has this facility been issued a Notice of Intent (NOI)? ☐ Yes ☒ No	If yes, the NOI No. is:
9	Does this facility have a construction permit (20.2.72/20.2.74 NMAC)? ☒ Yes ☐ No	If yes, the permit No. is: 1554-M1R3
10	Is this facility registered under a General permit (GCP-1, GCP-2, etc.)? ☐ Yes ☒ No	If yes, the register No. is:

Section 1-C: Facility Input Capacity & Production Rate

1	What is the facility's maximum input capacity, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 3623.1 MMBTU	Daily: 86,954.7 MMBTU	Annually: 31,738,356 MMBTU
b	Proposed	Hourly: 3623.1 MMBTU	Daily: 86,954.7 MMBTU	Annually: 31,738,356 MMBTU
2	What is the facility's maximum production rate, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 340.3 MWh	Daily: 8,395.2 MWh	Annually: 3,064,248 MWh

b	Proposed	Hourly: 340.3 MWh	Daily: 8,395.2 MWh	Annually: 3,064,248 MWh

Section 1-D: Facility Location Information

1	Section: 8 and 9	Range: 4 East	Township: 29 South	County: Doña Ana County	Elevation (ft): 3,730
2	UTM Zone: ☐ 12 or ☒ 13			Datum: ☒ NAD 27 ☐ NAD 83 ☐ WGS 84	
a	UTM E (in meters, to nearest 10 meters): 353,520			UTM N (in meters, to nearest 10 meters): 3,519,660	
b	**AND** Latitude (deg., min., sec.): 31° 48’ 17.433” N			Longitude (deg., min., sec.): 106° 32’ 50.639” W	
3	Name and zip code of nearest New Mexico town: Sunland Park, 88063				
4	Detailed Driving Instructions from nearest NM town (attach a road map if necessary): From the corner of Posey Road and McNutt Road (located in Sunland Park, New Mexico) drive east on McNutt Road (Highway 273) for approximately 0.6 miles to Racetrack Drive; at Racetrack Drive turn left (NE) on Racetrack Drive and proceed for approximately 0.9 miles to Doniphan Drive. At Doniphan Drive turn right (SE) and drive approximately 0.35 miles to the Rio Grande Plant entrance on the right, turn right into the plant and stop at the security check.				
5	The facility is 2.5 (distance) miles ESE (direction) of Sunland Park (nearest town).				
6	Status of land at facility (check one): ☒Private ☐ Indian/Pueblo ☐ Federal BLM ☐ Federal Forest Service ☐ Other (specify)				
7	List all municipalities, Indian tribes, and counties within a ten (10) mile radius (20.2.72.203.B.2 NMAC) of the property on which the facility is proposed to be constructed or operated: Doña Ana County, NM; Santa Teresa, NM; Canutillo, NM; El Paso, TX; El Paso County, TX; Juarez, Mexico; Sunland Park, NM. Indian Tribes: None.				
8	**20.2.72** NMAC applications **only**: Will the property on which the facility is proposed to be constructed or operated be closer than 50 km (31 miles) to other states, Bernalillo County, or a Class I area (see www.env.nm.gov/aqb/modeling/class1areas.html)? ☐ Yes ☐ No (20.2.72.206.A.7 NMAC) If yes, list all with corresponding distances in kilometers:				
9	Name nearest Class I area: Guadalupe Mountains National Park				
10	Shortest distance (in km) from facility boundary to the boundary of the nearest Class I area (to the nearest 10 meters): 145 km				
11	Distance (meters) from the perimeter of the Area of Operations (AO is defined as the plant site inclusive of all disturbed lands, including mining overburden removal areas) to nearest residence, school or occupied structure: 100 m				
12	Method(s) used to delineate the Restricted Area: Installation is fenced and has a private security guard service. “**Restricted Area**” is an area to which public entry is effectively precluded. Effective barriers include continuous fencing, continuous walls, or other continuous barriers approved by the Department, such as rugged physical terrain with steep grade that would require special equipment to traverse. If a large property is completely enclosed by fencing, a restricted area within the property may be identified with signage only. Public roads cannot be part of a Restricted Area.				
13	Does the owner/operator intend to operate this source as a portable stationary source as defined in 20.2.72.7.X NMAC? ☐ Yes ☒ No A portable stationary source is not a mobile source, such as an automobile, but a source that can be installed permanently at one location or that can be re-installed at various locations, such as a hot mix asphalt plant that is moved to different job sites.				
14	Will this facility operate in conjunction with other air regulated parties on the same property? ☒ No ☐ Yes If yes, what is the name and permit number (if known) of the other facility?				

Section 1-E: Proposed Operating Schedule (The 1-E.1 & 1-E.2 operating schedules may become conditions in the permit.)

1	Facility **maximum** operating $(\frac{hours}{day})$: 24	$(\frac{days}{week})$: 7	$(\frac{weeks}{year})$: 52	$(\frac{hours}{year})$: 8,760		
2	Facility’s maximum daily operating schedule (if less than 24 $\frac{hours}{day}$)? Start:		☐AM ☐PM	End:		☐AM ☐PM
3	Month and year of anticipated start of construction: N/A					
4	Month and year of anticipated construction completion: N/A					
5	Month and year of anticipated startup of new or modified facility: N/A					

6	Will this facility operate at this site for more than one year? ☒ Yes ☐ No

Section 1-F: Other Facility Information

1	Are there any current Notice of Violations (NOV), compliance orders, or any other compliance or enforcement issues related to this facility? ☐Yes ☒ No If yes, specify:		
a	If yes, NOV date or description of issue: N/A		NOV Tracking No: N/A
b	Is this application in response to any issue listed in 1-F, 1 or 1a above? ☐ Yes ☒ No If Yes, provide the 1c & 1d info below:		
c	Document Title: N/A	Date: N/A	Requirement # (or page # and paragraph #): N/A
d	Provide the required text to be inserted in this permit: N/A		
2	Is air quality dispersion modeling or modeling waiver being submitted with this application? ☐ Yes ☒ No		
3	Does this facility require an "Air Toxics" permit under 20.2.72.400 NMAC & 20.2.72.502, Tables A and/or B? ☒Yes ☐ No		
4	Will this facility be a source of federal Hazardous Air Pollutants (HAP)? ☒ Yes ☐ No		
a	If Yes, what type of source? ☐ **Major** (☐ ≥10 tpy of any single HAP **OR** ☐ ≥25 tpy of any combination of HAPS) **OR** ☒ **Minor** (☒ <10 tpy of any single HAP **AND** ☒ <25 tpy of any combination of HAPS)		
5	Is any unit exempt under 20.2.72.202.B.3 NMAC? ☒ Yes ☐ No		
a	If yes, include the name of company providing commercial electric power to the facility: El Paso Electric Company Commercial power is purchased from a commercial utility company, which specifically does not include power generated on site for the sole purpose of the user.		

Section 1-G: Streamline Application **(This section applies to 20.2.72.300 NMAC Streamline applications only)**

1	☐ I have filled out Section 18, "Addendum for Streamline Applications." ☒ N/A (This is not a Streamline application.)

Section 1-H: Current Title V Information - Required for all applications from TV Sources

(Title V-source required information for all applications submitted pursuant to 20.2.72 NMAC (Minor Construction Permits), or 20.2.74/20.2.79 NMAC (Major PSD/NNSR applications), and/or 20.2.70 NMAC (Title V))

1	Responsible Official (R.O.) (20.2.70.300.D.2 NMAC): Steven Buraczyk	Phone: 915-543-4368
a	R.O. Title: Senior Vice President of Operations	R.O. e-mail: steve.buraczyk@epelectric.com
b	R. O. Address: P.O. Box 982 El Paso, Texas 79960	
2	Alternate Responsible Official (20.2.70.300.D.2 NMAC): Daniel Perez	Phone: 915-543-4166
a	A. R.O. Title: Supervisor – Environmental Compliance	A. R.O. e-mail: daniel.perez@epelectric.com
b	A. R. O. Address: P.O. Box 982 El Paso, Texas 79960	
3	Company's Corporate or Partnership Relationship to any other Air Quality Permittee (List the names of any companies that have operating (20.2.70 NMAC) permits and with whom the applicant for this permit has a corporate or partnership relationship): Arizona Public Service Company, Salt River Project, Southern California Edison Company, Public Service Company of New Mexico, Texas-Energy & Power.	
4	Name of Parent Company ("Parent Company" means the primary name of the organization that owns the company to be permitted wholly or in part.): El Paso Electric Company	
a	Address of Parent Company: 100 N. Stanton, El Paso, TX 79901	
5	Names of Subsidiary Companies ("Subsidiary Companies" means organizations, branches, divisions or subsidiaries, which are owned, wholly or in part, by the company to be permitted.): N/A	

6	Telephone numbers & names of the owners' agents and site contacts familiar with plant operations: N/A
7	Affected Programs to include Other States, local air pollution control programs (i.e. Bernalillo) and Indian tribes: Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B)? If yes, state which ones and provide the distances in kilometers: Yes, within 0.1 km of Texas and the City of El Paso.

Section 1-I – Submittal Requirements

Each 20.2.73 NMAC (**NOI**), a 20.2.70 NMAC (**Title V**), a 20.2.72 NMAC (**NSR** minor source), or 20.2.74 NMAC (**PSD**) application package shall consist of the following:

Hard Copy Submittal Requirements:

1) One hard copy **original signed and notarized application package printed double sided 'head-to-toe' 2-hole punched** as we bind the document on top, not on the side; except Section 2 (landscape tables), which should be head-to-head. Please use **numbered tab separators** in the hard copy submittal(s) as this facilitates the review process. For NOI submittals only, hard copies of UA1, Tables 2A, 2D & 2F, Section 3 and the signed Certification Page are required. Please include a copy of the check on a separate page.

2) If the application is for a minor NSR, PSD, NNSR, or Title V application, include one working hard **copy** for Department use. This copy should be printed in book form, 3-hole punched, and **must be double sided**. Note that this is in addition to the head-to-to 2-hole punched copy required in 1) above. Minor NSR Technical Permit revisions (20.2.72.219.B NMAC) only need to fill out Sections 1-A, 1-B, 3, and should fill out those portions of other Section(s) relevant to the technical permit revision. TV Minor Modifications need only fill out Sections 1-A, 1-B, 1-H, 3, and those portions of other Section(s) relevant to the minor modification. NMED may require additional portions of the application to be submitted, as needed.

3) The entire NOI or Permit application package, including the full modeling study, should be submitted electronically. Electronic files for applications for NOIs, any type of General Construction Permit (GCP), or technical revisions to NSRs must be submitted with compact disk (CD) or digital versatile disc (DVD). For these permit application submittals, two CD copies are required (in sleeves, not crystal cases, please), with additional CD copies as specified below. NOI applications require only a single CD submittal. Electronic files for other New Source Review (construction) permits/permit modifications or Title V permits/permit modifications can be submitted on CD/DVD or sent through AQB's secure file transfer service.

Electronic files sent by (check one):

☒ CD/DVD attached to paper application

☐ secure electronic transfer. Air Permit Contact Name______________________________

Email______________________________

Phone number ______________________________

a. If the file transfer service is chosen by the applicant, after receipt of the application, the Bureau will email the applicant with instructions for submitting the electronic files through a secure file transfer service. Submission of the electronic files through the file transfer service needs to be completed within 3 business days after the invitation is received, so the applicant should ensure that the files are ready when sending the hard copy of the application. The applicant will not need a password to complete the transfer. **Do not use the file transfer service for NOIs, any type of GCP, or technical revisions to NSR permits.**

4) Optionally, the applicant may submit the files with the application on compact disk (CD) or digital versatile disc (DVD) following the instructions above and the instructions in 5 for applications subject to PSD review.

5) If **air dispersion modeling** is required by the application type, include the **NMED Modeling Waiver** and/or electronic air dispersion modeling report, input, and output files. The dispersion modeling ***summary report only*** should be submitted as hard copy(ies) unless otherwise indicated by the Bureau.

6) If the applicant submits the electronic files on CD and the application is subject to PSD review under 20.2.74 NMAC (PSD) or NNSR under 20.2.79 NMC include,
   a. one additional CD copy for US EPA,
   b. one additional CD copy for each federal land manager affected (NPS, USFS, FWS, USDI) and,
   c. one additional CD copy for each affected regulatory agency other than the Air Quality Bureau.

   If the application is submitted electronically through the secure file transfer service, these extra CDs do not need to be submitted.

Electronic Submittal Requirements [in addition to the required hard copy(ies)]:

1) All required electronic documents shall be submitted as 2 separate CDs or submitted through the AQB secure file transfer service. Submit a single PDF document of the entire application as submitted and the individual documents comprising the application.

2) The documents should also be submitted in Microsoft Office compatible file format (Word, Excel, etc.) allowing us to access the text and formulas in the documents (copy & paste). Any documents that cannot be submitted in a Microsoft Office compatible

format shall be saved as a PDF file from within the electronic document that created the file. If you are unable to provide Microsoft office compatible electronic files or internally generated PDF files of files (items that were not created electronically: i.e. brochures, maps, graphics, etc,), submit these items in hard copy format. We must be able to review the formulas and inputs that calculated the emissions.

3) It is preferred that this application form be submitted as 4 electronic files (3 MSWord docs: Universal Application section 1 [UA1], Universal Application section 3-19 [UA3], and Universal Application 4, the modeling report [UA4]) and 1 Excel file of the tables (Universal Application section 2 [UA2]). Please include as many of the 3-19 Sections as practical in a single MS Word electronic document. Create separate electronic file(s) if a single file becomes too large or if portions must be saved in a file format other than MS Word.

4) The electronic file names shall be a maximum of 25 characters long (including spaces, if any). The format of the electronic Universal Application shall be in the format: "A-3423-FacilityName". The "A" distinguishes the file as an application submittal, as opposed to other documents the Department itself puts into the database. Thus, all electronic application submittals should begin with "A-". Modifications to existing facilities should use the core permit number (i.e. '3423') the Department assigned to the facility as the next 4 digits. Use 'XXXX' for new facility applications. The format of any separate electronic submittals (additional submittals such as non-Word attachments, re-submittals, application updates) and Section document shall be in the format: "A-3423-9-description", where "9" stands for the section # (in this case Section 9-Public Notice). Please refrain, as much as possible, from submitting any scanned documents as this file format is extremely large, which uses up too much storage capacity in our database. Please take the time to fill out the header information throughout all submittals as this will identify any loose pages, including the Application Date (date submitted) & Revision number (0 for original, 1, 2, etc.; which will help keep track of subsequent partial update(s) to the original submittal. Do not use special symbols (#, @, etc.) in file names. The footer information should not be modified by the applicant.

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Table 2-A: Regulated Emission Sources

Unit and stack numbering must correspond throughout the application package. If applying for a NOI under 20.2.73 NMAC, equipment exemptions under 2.72.202 NMAC do not apply.

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
EPN-3	Unit #6 Boiler	Babcock & Wilcox	BW CNRB 465	19199	610 MMBTU/hr	610 MMBTU/hr	Unknonwn January 1, 1956	 EPN-3 (Total)	10100601	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
EPN-4	Unit #7 Boiler	Babcock & Wilcox	BW CNS 9926	19680	590 MMBTU/hr	590 MMBTU/hr	Unknonwn January 1, 1958	 EPN-4 (Total)	10100601	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
EPN-1	Unit #8 Boiler	Babcock & Wilcox	BW CNRB 298	22896	1,535 MMBTU/hr	1,535 MMBTU/hr	Unknonwn January 10, 1968	LoNOx, Water Injection with Flue Gas Recirculation EPN-1 (Total)	10100601	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
F-1	Cooling Tower 6	N/A	N/A	N/A	33,600 gpm	33,600 gpm	Unknonwn June 1, 1956	 F-1	2820000000	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
F-1	Cooling Tower 7	N/A	N/A	N/A	24,000 gpm	24,000 gpm	Unknonwn January 1, 1958	 F-1	2820000000	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
F-1	Cooling Tower 8	N/A	N/A	N/A	55,000 gpm	55,000 gpm	Summer 2004 1/10/1968; Reconstructed 2004	 F-1	2820000000	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
F-2	Piping Fugitives	N/A	N/A	N/A	N/A	N/A	N/A N/A	 F-2	30288801	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
GT-9	Unit #9 Natural gas-fired turbine	GE	LMS 100 PA	Unit Serial #821340 Engine Serial # 878-168	142,576 HP	142,576 HP	Unknonwn August 2, 2012	SCR & Oxidation Catalyst GT-9	20100201	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
CT-9	Cooling Tower 9	SPX	F434 A24 A4.002A	6021201	6,900 gpm	6,900 gpm	Unknonwn August 2, 2012	 CT-9	38500102	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
FUG-9	Piping Fugitives	N/A	N/A	N/A	N/A	N/A	N/A August 2, 2012		20180001	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced		
EG-1	Emergency Diesel Generator	MTU	DS250D6S	375442	418 HP	418 HP	July 1, 2014 October 17, 2014	 EG-1	20200102	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	CI	
SE-1	Standby Diesel Engine	Cummins	QSB4.5	73882737	110 HP	110 HP	August 10, 2015 November 4, 2015	 SE-1	20200102	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	CI	

[1] Unit numbers must correspond to unit numbers in the previous permit unless a complete cross reference table of all units in both permits is provided.
[2] Specify dates required to determine regulatory applicability.
[3] To properly account for power conversion efficiencies, generator set rated capacity shall be reported as the rated capacity of the engine in horsepower, not the kilowatt capacity of the generator set.
[4] "4SLB" means four stroke lean burn engine, "4SRB" means four stroke rich burn engine, "2SLB" means two stroke lean burn engine, "CI" means compression ignition, and "SI" means spark ignition

Table 2-B: Insignificant Activities[1] (20.2.70 NMAC) OR Exempted Equipment (20.2.72 NMAC)

All 20.2.70 NMAC (Title V) applications must list all Insignificant Activities in this table. All 20.2.72 NMAC applications must list Exempted Equipment in this table. If equipment listed on this table is exempt under 20.2.72.202.B.5, include emissions calculations and emissions totals for 202.B.5 "similar functions" units, operations, and activities in Section 6, Calculations. Equipment and activities exempted under 20.2.72.202 NMAC may not necessarily be Insignificant under 20.2.70 NMAC (and vice versa). Unit & stack numbering must be consistent throughout the application package. Per Exemptions Policy 02-012.00 (see http://www.env.nm.gov/aqb/permit/aqb_pol.html), 20.2.72.202.B NMAC Exemptions do not apply, but 20.2.72.202.A NMAC exemptions do apply to NOI facilities under 20.2.73 NMAC. List 20.2.72.301.D.4 NMAC Auxiliary Equipment for Streamline applications in Table 2-A. The List of Insignificant Activities (for TV) can be found online at https://www.env.nm.gov/wp-content/uploads/sites/2/2017/10/InsignificantListTitleV.pdf. TV sources may elect to enter both TV Insignificant Activities and Part 72 Exemptions on this form.

Unit Number	Source Description	Manufacturer	Model No.	Max Capacity	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5)	Date of Manufacture /Reconstruction[2]	For Each Piece of Equipment, Check Onc
			Serial No.	Capacity Units	Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Installation /Construction[2]	
Maintenance Paints/Coatings	Paints and coatings are used for maintenance of equipment and buildings				20.2.72.202 A.(1)		☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
					IA List Item #1.a		
Plant Cleaning and Maintenance	Cleaining solvents and chemicals are used for maintenance purposes				20.2.72.202 A.(2)		☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
					IA List Item #1.a		
Electrical Maintenance	Maintenance of electrical equipment is performed on site. Solvents used for this purpose				20.2.72.202 A.(2)		☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
					IA List Item #2		
AST4	Diesel oil storage tank 4. Storage of diesel fuel oil with vapor pressure < 10 mmHg			24,374	20.2.72.202 B.(2)(a)	2006	☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
				bbl	IA List Item #5	1971	
Piping fugitives	Emissions from piping in diesel oil service				20.2.72.202 B.(2)(a)		☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
					IA List Item #1.a		
AST9	Aqueous Ammonia < 20% @ 40 psig			476	20.2.72.202 B.(2)(a)		☒ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
				bbl	IA List Item #1.a		
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
							☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced

[1] Insignificant activities exempted due to size or production rate are defined in 20.2.70.300.D.6, 20.2.70.7.Q NMAC, and the NMED/AQB List of Insignificant Activities, dated September 15, 2008. Emissions from these insignificant activities do not need to be reported, unless specifically requested.

[2] Specify date(s) required to determine regulatory applicability.

Table 2-C: Emissions Control Equipment

Unit and stack numbering must correspond throughout the application package. Only list control equipment for TAPs if the TAP's maximum uncontrolled emissions rate is over its respective threshold as listed in 20.2.72 NMAC, Subpart V, Tables A and B. In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and (e) NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions.

Control Equipment Unit No.	Control Equipment Description	Date Installed	Controlled Pollutant(s)	Controlling Emissions for Unit Number(s)[1]	Efficiency (% Control by Weight)	Method used to Estimate Efficiency
Boiler 8	Low NOx Burners	Nov-13	NOx	Boiler 8	N/A	CEMS
Boiler 8	Flue gas recirculation	Jul-10	NOx	Boiler 8	N/A	CEMS
Turbine Unit 9	Selective Catalytic Reduction (SCR) System	Aug-12	NOx	Turbine Unit 9	~ 88.8%	Nominal control efficiency from vendor data. Actual efficiency will vary based on inlet concentration
Turbine Unit 9	Oxidation Catalyst	Aug-12	CO	Turbine Unit 9	~ 77.5%	Nominal control efficiency from vendor data. Actual efficiency will vary based on inlet concentration
Turbine Unit 9	Oxidation Catalyst	Aug-12	VOC	Turbine Unit 9	~ 19%	Nominal control efficiency from vendor data. Actual efficiency will vary based on inlet concentration

[1] List each control device on a separate line. For each control device, list all emission units controlled by the control device.

Table 2-D: Maximum Emissions (under normal operating conditions)

☐ **This Table was intentionally left blank because it would be identical to Table 2-E.**

Maximum Emissions are the emissions at maximum capacity and prior to (in the absence of) pollution control, emission-reducing process equipment, or any other emission reduction. Calculate the hourly emissions using the worst case hourly emissions for each pollutant. For each pollutant, calculate the annual emissions as if the facility were operating at maximum plant capacity without pollution controls for 8760 hours per year, unless otherwise approved by the Department. List Hazardous Air Pollutants (HAP) & Toxic Air Pollutants (TAPs) in Table 2-I. Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
EPN-3 (Condensable)	-	-	-	-	-	-	-	-	3.77	16.49	-	-	-	-	-	-	-	-
EPN-3 (Filterable)	-	-	-	-	-	-	-	-	1.26	5.50	-	-	-	-	-	-	-	-
EPN-3 (Total)	183.0	802.0	1400.0	243.0	3.60	15.90	0.08	0.31	5.00	21.99	5.00	22.00	5.00	2.00	-	-	-	-
EPN-4 (Condensable)	-	-	-	-	-	-	-	-	3.60	15.90	-	-	-	-	-	-	-	-
EPN-4 (Filterable)	-	-	-	-	-	-	-	-	1.20	5.30	-	-	-	-	-	-	-	-
EPN-4 (Total)	177.0	775.0	1400.0	235.0	3.50	15.40	0.08	0.30	4.90	21.30	4.90	21.30	4.90	21.30	-	-	-	-
EPN-1 (Condensable)	-	-	-	-	-	-	-	-	9.50	36.40	-	-	-	-	-	-	-	-
EPN-1 (Filterable)	-	-	-	-	-	-	-	-	3.20	12.10	-	-	-	-	-	-	-	-
EPN-1 (Total)	460.50/415.00	1514.0	1000.0	536.0	9.10	35.10	0.21	0.68	12.60	48.50	12.60	48.50	12.60	48.50	-	-	-	-
F-1	-	-	-	-	-	-	-	-	17.90	78.50	1.10	5.00	0.023	0.1	-	-	-	-
F-2	-	-	-	-	0.69	3.04	-	-	-	-	-	-	-	-	2.70E-05	1.20E-04	-	-
GT-9 (Condensable)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GT-9 (Filterable)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GT-9 (Total)	81.1	330.3	140.4	481.5	2.30	9.20	0.10	0.36	3.60	14.48	3.60	14.48	3.60	14.48	-	-	-	-
CT-9	-	-	-	-	-	-	-	-	3.30	1.40	0.02	0.09	0.0004	0.002	-	-	-	-
FUG-9	-	-	-	-	0.01	0.046	-	-	-	-	-	-	-	-	4E-07	1.8E-06	-	-
Totals	901.60/856.10	3421.30	3940.40	1495.50	19.20	78.69	0.47	1.65	47.30	186.17	27.22	111.37	26.12	86.38	2.74E-05	1.22E-04	-	-

[1]**Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but PM is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

Table 2-E: Requested Allowable Emissions

Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E^{-4}).

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
EPN-3 (Condensable)	-	-	-	-	-	-	-	-	3.77	16.50	-	-	-	-	-	-	-	-
EPN-3 (Filterable)	-	-	-	-	-	-	-	-	1.26	5.50	-	-	-	-	-	-	-	-
EPN-3 (Total)	183.00	802.00	1400.00	243.00	3.60	15.90	0.08	0.31	5.00	22.00	5.00	22.00	5.00	2.00	-	-	Negligible	Negligible
EPN-4 (Condensable)	-	-	-	-	-	-	-	-	3.60	15.90	-	-	-	-	-	-	-	-
EPN-4 (Filterable)	-	-	-	-	-	-	-	-	1.20	5.30	-	-	-	-	-	-	-	-
EPN-4 (Total)	177.00	775.00	1400.00	235.00	3.50	15.40	0.08	0.30	4.90	21.30	4.90	21.30	4.90	21.30	-	-	Negligible	Negligible
EPN-1 (Condensable)	-	-	-	-	-	-	-	-	9.50	36.40	-	-	-	-	-	-	-	-
EPN-1 (Filterable)	-	-	-	-	-	-	-	-	3.20	12.10	-	-	-	-	-	-	-	-
EPN-1 (Total)	460.50/415.00	1514.00	1000.00	536.00	9.10	35.10	0.21	0.68	12.60	48.50	12.60	48.50	12.60	48.50	-	-	Negligible	Negligible
F-1	-	-	-	-	-	-	-	-	17.90	78.50	1.10	5.00	0.02	0.10	-	-	-	-
F-2	-	-	-	-	0.69	3.00	-	-	-	-	-	-	-	-	2.70E-05	1.20E-04		
GT-9 (Condensable)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GT-9 (Filterable)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GT-9 (Total)	22.90	39.10	30.30	94.10	2.26	9.19	0.10	0.36	3.60	14.48	3.60	14.48	3.60	14.48	-	-	-	-
CT-9	-	-	-	-	-	-	-	-	3.30	1.40	0.02	0.09	0.0004	0.002	-	-	-	-
FUG-9	-	-	-	-	0.01	0.046	-	-	-	-	-	-	-	-	4E-07	1.8E-06	-	-
Totals	843.4/797.9	3130.10	3830.30	1108.1	19.16	78.64	0.47	1.65	47.30	186.18	27.22	111.37	26.12	86.38	2.74E-05	1.22E-04	Negligible	Negligible

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

Table 2-F: Additional Emissions during Startup, Shutdown, and Routine Maintenance (SSM)

☑ This table is intentionally left blank since all emissions at this facility due to routine or predictable startup, shutdown, or scehduled maintenance are no higher than those listed in Table 2-E and a malfunction emission limit is not already permitted or requested. If you are required to report GHG emissions as described in Section 6a, include any GHG emissions during Startup, Shutdown, and/or Scheduled Maintenance (SSM) in Table 2-P. Provide an explanations of SSM emissions in Section 6 and 6a.

All applications for facilities that have emissions during routine our predictable startup, shutdown or scheduled maintenance (SSM)[1], including NOI applications, must include in this table the Maximum Emissions during routine or predictable startup, shutdown and scheduled maintenance (20.2.7 NMAC, 20.2.72.203.A.3 NMAC, 20.2.73.200.D.2 NMAC). In Section 6 and 6a, provide emissions calculations for all SSM emissions reported in this table. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (https://www.env.nm.gov/aqb/permit/aqb_pol.html) for more detailed instructions. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		PM[2]		PM10[2]		PM2.5[2]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Totals																		

[1] **For instance**, if the short term steady-state Table 2-E emissions are 5 lb/hr and the SSM rate is 12 lb/hr, enter 7 lb/hr in this table. If the annual steady-state Table 2-E emissions are 21.9 TPY, and the number of scheduled SSM events result in annual emissions of 31.9 TPY, enter 10.0 TPY in the table below.

[2] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

Table 2-G: Stack Exit and Fugitive Emission Rates for Special Stacks

☑ I have elected to leave this table blank because this facility does not have any stacks/vents that split emissions from a single source or combine emissions from more than one source listed in table 2-A. Additionally, the emission rates of all stacks match the Requested allowable emission rates stated in Table 2-E.

Use this table to list stack emissions (requested allowable) from split and combined stacks. List Toxic Air Pollutants (TAPs) and Hazardous Air Pollutants (HAPs) in Table 2-I. List all fugitives that are associated with the normal, routine, and non-emergency operation of the facility. Unit and stack numbering must correspond throughout the application package. Refer to Table 2-E for instructions on use of the "-" symbol and on significant figures.

Stack No.	Serving Unit Number(s) from Table 2-A	NOx		CO		VOC		SOx		PM		PM10		PM2.5		☐ H_2S or ☐ Lead	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Totals:																	

Table 2-H: Stack Exit Conditions

Unit and stack numbering must correspond throughout the application package. Include the stack exit conditions for each unit that emits from a stack, including blowdown venting parameters and tank emissions. If the facility has multiple operating scenarios, complete a separate Table 2-H for each scenario and, for each, type scenario name here:

Stack Number	Serving Unit Number(s) from Table 2-A	Orientation (H-Horizontal V=Vertical)	Rain Caps (Yes or No)	Height Above Ground (ft)	Temp. (F)	Flow Rate		Moisture by Volume (%)	Velocity (ft/sec)	Inside Diameter (ft)
						(acfs)	(dscfs)			
EPN-3	Unit #6 Boiler	V	No	118	251	2003	-	-	29.5	9.30
EPN-4	Unit #7 Boiler	V	No	118	266	1792	-	-	26.4	9.30
EPN-1	Unit #8 Boiler	V	No	135	259	4693	-	-	33.8	13.30
F-1	Cooling Towers	N/A	N/A	38	67.5	-	-	-	-	-
F-2	Piping Fugitives	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GT-9	Unit 9- Turbine	V	No	90	773	-	5292	~11%	36.97	13.50
CT-9	Cooling Tower 9	N/A	N/A	25	67.5	-	-	-	-	-

Table 2-I: Stack Exit and Fugitive Emission Rates for HAPs and TAPs

In the table below, report the Potential to Emit for each HAP from each regulated emission unit listed in Table 2-A, only if the entire facility emits the HAP at a rate greater than or equal to one (1) ton per year For each such emission unit, HAPs shall be reported to the nearest 0.1 tpy. Each facility-wide Individual HAP total and the facility-wide Total HAPs shall be the sum of all HAP sources calculated to the nearest 0.1 ton per year. Per 20.2.72.403.A.1 NMAC, facilities not exempt [see 20.2.72.402.C NMAC] from TAP permitting shall report each TAP that has an uncontrolled emission rate in excess of its pounds per hour screening level specified in 20.2.72.502 NMAC. TAPs shall be reported using one more significant figure than the number of significant figures shown in the pound per hour threshold corresponding to the substance. Use the HAP nomenclature as it appears in Section 112 (b) of the 1990 CAAA and the TAP nomenclature as it listed in 20.2.72.502 NMAC. Include tank-flashing emissions estimates of HAPs in this table. For each HAP or TAP listed, fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected or the pollutant is emitted in a quantity less than the threshold amounts described above.

Stack No.	Unit No.(s)	Total HAPs		Acetaldehyde ☑ HAP or ☐ TAP		Acrolein ☑ HAP or ☐ TAP		Ammonia ☐ HAP or ☑ TAP		Benzene ☑ HAP or ☐ TAP		Chlorine ☑ HAP or ☐ TAP		Ethylbenzene ☑ HAP or ☐ TAP		Formaldehyde ☑ HAP or ☐ TAP		Hexane ☑ HAP or ☐ TAP	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
EPN-3	Unit #6 Boiler	0.007	0.03	0.0006	0.003	0.0005	0.002	-	-	0.001	0.005	-	-	0.001	0.006	0.002	0.010	0.001	0.004
EPN-4	Unit #7 Boiler	0.006	0.03	0.0006	0.003	0.0005	0.002	-	-	0.001	0.005	-	-	0.001	0.006	0.002	0.010	0.001	0.004
EPN-1	Unit #8 Boiler	0.02	0.1	0.001	0.006	0.001	0.005	-	-	0.003	0.01	-	-	0.003	0.01	0.006	0.02	0.002	0.008
GT-9	Unit #9 Turbine	0.08	0.4	0.03	0.14	0.01	0.02	6	24.4	0.0008	0.003	-	-	0.03	0.12	0.02	0.07	-	-
F-2	Piping Fugitives	0.46	2.00	-	-	-	-	-	-	-	-	0.46	2.00	-	-	-	-	-	-
FUG-9	Piping Fugitives Unit 9	0.11	0.5	-	-	-	-	0.17	0.72	-	-	0.11	0.5	-	-	-	-	-	-
Sub-Total from Table 2-I (P.1)		0.68	2.98																
Sub-Total from Table 2-I (P.2)		0.23	0.99																
Totals:		0.91	3.97	0.04	0.16	0.01	0.03	6.17	25.12	0.01	0.02	0.57	2.50	0.03	0.14	0.03	0.12	0.00	0.02

Table 2-I: Stack Exit and Fugitive Emission Rates for HAPs and TAPs

In the table below, report the Potential to Emit for each HAP from each regulated emission unit listed in Table 2-A, only if the entire facility emits the HAP at a rate greater than or equal to one (1) ton per year For each such emission unit, HAPs shall be reported to the nearest 0.1 tpy. Each facility-wide Individual HAP total and the facility-wide Total HAPs shall be the sum of all HAP sources calculated to the nearest 0.1 ton per year. Per 20.2.72.403.A.1 NMAC, facilities not exempt [see 20.2.72.402.C NMAC] from TAP permitting shall report each TAP that has an uncontrolled emission rate in excess of its pounds per hour screening level specified in 20.2.72.502 NMAC. TAPs shall be reported using one more significant figure than the number of significant figures shown in the pound per hour threshold corresponding to the substance. Use the HAP nomenclature as it appears in Section 112 (b) of the 1990 CAAA and the TAP nomenclature as it listed in 20.2.72.502 NMAC. Include tank-flashing emissions estimates of HAPs in this table. For each HAP or TAP listed, fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected or the pollutant is emitted in a quantity less than the threshold amounts described above.

Stack No.	Unit No.(s)	Total HAPs		Naphthalene ☑ HAP or ☐ TAP		Polycyclic Aromatic Hydrocarbons ☑ HAP or ☐ TAP		Propylene Oxide ☑ HAP or ☐ TAP		Toluene ☑ HAP or ☐ TAP		Xylene ☑ HAP or ☐ TAP							
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr						
EPN-3	Unit #6 Boiler	0.01	0.04	0.0002	0.0009	-	-	-	-	0.01	0.02	0.004	0.02						
EPN-4	Unit #7 Boiler	0.01	0.04	0.0002	0.0008	-	-	-	-	0.005	0.02	0.004	0.02						
EPN-1	Unit #8 Boiler	0.02	0.09	0.0005	0.002	-	-	-	-	0.01	0.05	0.01	0.04						
GT-9	Unit #9 Turbine	0.19	0.82	0.001	0.005	0.002	0.008	0.02	0.10	0.11	0.47	0.05	0.23						
F-2	Piping Fugitives	-	-	-	-	-	-	-	-	-	-	-	-						
FUG-9	Piping Fugitives Unit 9	-	-	-	-	-	-	-	-	-	-	-	-						
Totals:				0.002	0.01	0.002	0.01	0.02	0.10	0.13	0.56	0.07	0.30						

Table 2-J: Fuel

Specify fuel characteristics and usage. Unit and stack numbering must correspond throughout the application package.

Unit No.	Fuel Type (low sulfur Diesel, ultra low sulfur diesel, Natural Gas, Coal, …)	Fuel Source: purchased commercial, pipeline quality natural gas, residue gas, raw/field natural gas, process gas (e.g. SRU tail gas) or other	Specify Units				
			Lower Heating Value	Hourly Usage	Annual Usage	% Sulfur	% Ash
EPN-3	Natural Gas	Pipeline quality natural gas	924 BTU/scf	0.661 MMscf/hr	5786.2 MMscf/yr	0.0005	Negligible
EPN-4	Natural Gas	Pipeline quality natural gas	924 BTU/scf	0.639 MMscf/hr	5596.1 MMscf/yr	0.0005	Negligible
EPN-1	Natural Gas	Pipeline quality natural gas	924 BTU/scf	1.662 MMscf/hr	14560.5 MMscf/yr	0.0005	Negligible
GT-9	Natural Gas	Pipeline quality natural gas	924 BTU/scf	0.867 MMscf/hr	7594.92 MMscf/yr	0.0005	Negligible

Table 2-K: Liquid Data for Tanks Listed in Table 2-L

For each tank, list the liquid(s) to be stored in each tank. If it is expected that a tank may store a variety of hydrocarbon liquids, enter "mixed hydrocarbons" in the Composition column for that tank and enter the corresponding data of the most volatile liquid to be stored in the tank. If tank is to be used for storage of different materials, list all the materials in the "All Calculations" attachment, run the newest version of TANKS on each, and use the material with the highest emission rate to determine maximum uncontrolled and requested allowable emissions rate. The permit will specify the most volatile category of liquids that may be stored in each tank. Include appropriate tank-flashing modeling input data. Use additional sheets if necessary. Unit and stack numbering must correspond throughout the application package.

Tank No.	SCC Code	Material Name	Composition	Liquid Density (lb/gal)	Vapor Molecular Weight (lb/lb*mol)	Average Storage Conditions		Max Storage Conditions	
						Temperature (°F)	True Vapor Pressure (psia)	Temperature (°F)	True Vapor Pressure (psia)

Table 2-L: Tank Data

Include appropriate tank-flashing modeling input data. Use an addendum to this table for unlisted data categories. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary. See reference Table 2-L2. Note: 1.00 bbl = 10.159 M3 = 42.0 gal

Tank No.	Date Installed	Materials Stored	Seal Type (refer to Table 2-LR below)	Roof Type (refer to Table 2-LR below)	Capacity		Diameter (M)	Vapor Space (M)	Color (from Table VI-C)		Paint Condition (from Table VI-C)	Annual Throughput (gal/yr)	Turn-overs (per year)
					(bbl)	(M^3)			Roof	Shell			

Table 2-L2: Liquid Storage Tank Data Codes Reference Table

Roof Type	Seal Type, Welded Tank Seal Type		Seal Type, Riveted Tank Seal Type		Roof, Shell Color	Paint Condition
FX: Fixed Roof	**Mechanical Shoe Seal**	**Liquid-mounted resilient seal**	**Vapor-mounted resilient seal**	**Seal Type**	**WH**: White	Good
IF: Internal Floating Roof	**A**: Primary only	**A**: Primary only	**A**: Primary only	**A**: Mechanical shoe, primary only	**AS**: Aluminum (specular)	Poor
EF: External Floating Roof	**B**: Shoe-mounted secondary	**B**: Weather shield	**B**: Weather shield	**B**: Shoe-mounted secondary	**AD**: Aluminum (diffuse)	
P: Pressure	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**LG**: Light Gray	
					MG: Medium Gray	
					BL: Black	
					OT: Other (specify)	

Note: 1.00 bbl = 0.159 M^3 = 42.0 gal

Table 2-M: Materials Processed and Produced (Use additional sheets as necessary.)

Material Processed				Material Produced			
Description	**Chemical Composition**	**Phase (Gas, Liquid, or Solid)**	**Quantity (specify units)**	**Description**	**Chemical Composition**	**Phase**	**Quantity (specify units)**
Natural Gas-Boilers	Hydrocarbons	Gas	Up to 2.962 MMscf/hr	Electric Power			Up to 245 MW
Natural Gas-Turbine	Hydrocarbons	Gas	Up to 0.867 MMscf/hr	Electric Power			Up to 94.5 MW

Table 2-N: CEM Equipment

Enter Continuous Emissions Measurement (CEM) Data in this table. If CEM data will be used as part of a federally enforceable permit condition, or used to satisfy the requirements of a state or federal regulation, include a copy of the CEM's manufacturer specification sheet in the Information Used to Determine Emissions attachment. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Stack No.	Pollutant(s)	Manufacturer	Model No.	Serial No.	Sample Frequency	Averaging Time	Range	Sensitivity	Accuracy
EPN-3	CO	Thermo Electron	48 i	0512011641	Continuous	60 seconds	0-500, 0-5000	4.0 ppm	+/- 0.1 ppm
EPN-3	NOx	Thermo Electron	42 i	0512011630	Continuous	60 seconds	0-500	0.04 ppb	+/- 0.4 ppb (500 ppb range)
EPN-4	CO	Thermo Electron	48 i	0512011642	Continuous	60 seconds	0-500, 0-5000	4.0 ppm	+/- 0.1 ppm
EPN-4	NOx	Thermo Electron	42 i	0512011631	Continuous	60 seconds	0-500	0.04 ppb	+/- 0.4 ppb (500 ppb range)
EPN-1	CO	Thermo Electron	48 i	0512011643	Continuous	60 seconds	0-500, 0-5000	4.0 ppm	+/- 0.1 ppm
EPN-1	NOx	Thermo Electron	42 i	0512011632	Continuous	60 seconds	0-500	0.04 ppb	+/- 0.4 ppb (500 ppb range)
GT-9	NOx	Thermo Electron	42 i -LS	1207251988	Continuous	60 seconds	0-200 ppm	0.04 ppm	+/- 0.4 ppb (500 ppb range)
GT-9	CO	Thermo Electron	48 i	1207252126	Continuous	60 seconds	0-200 ppm	4 ppm	+/- 0.1 ppm

Table 2-O: Parametric Emissions Measurement Equipment

Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Unit No.	Parameter/Pollutant Measured	Location of Measurement	Unit of Measure	Acceptable Range	Frequency of Maintenance	Nature of Maintenance	Method of Recording	Averaging Time
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 2-P: Greenhouse Gas Emissions

Applications submitted under 20.2.70, 20.2.72, & 20.2.74 NMAC are required to complete this Table. Power plants, Title V major sources, and PSD major sources must report and calculate all GHG emissions for each unit. Applicants must report potential emission rates in short tons per year (see Section 6.a for assistance). Include GHG emissions during Startup, Shutdown, and Scheduled Maintenance in this table. For minor source facilities that are not power plants, are not Title V, or are not PSD, there are three options for reporting GHGs 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHG as a second separate unit; OR 3) check the following box ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

		CO_2 ton/yr	N_2O ton/yr	CH_4 ton/yr	SF_6 ton/yr	PFC/HFC ton/yr[2]									Total GHG Mass Basis ton/yr[4]	Total CO_2e ton/yr[5]
Unit No.	**GWPs [1]**	**1**	**298**	**25**	**22,800**	**footnote 3**										
EPN-3	**mass GHG**	312,539.89	0.59	5.89	-										312,546	
	CO_2e	312,539.89	175.82	147.25	-											312,863
EPN-4	**mass GHG**	302,292.68	0.57	5.70	-										302,299	
	CO_2e	302,292.68	169.86	142.50	-											302,605
EPN-1	**mass GHG**	786,473.32	1.48	14.82	-										786,490	
	CO_2e	786,473.32	441.04	370.50	-											787,285
GT-9	**mass GHG**	423,312.22	0.80	7.98	-										423,321	
	CO_2e	423,312.22	238.40	199.50	-											423,750
	mass GHG															
	CO_2e															
	mass GHG															
	CO_2e															
	mass GHG															
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	CO_2e															
	mass GHG															
	CO_2e															
	mass GHG															
	CO2e															
Total	**mass GHG**	1,824,618	3.44	34.39											1,824,656	
	CO_2e	1,824,618	1,025.12	859.75												1,826,503

[1] **GWP** (Global Warming Potential): Applicants must use the most current GWPs codified in Table A-1 of 40 CFR part 98. GWPs are subject to change, therefore, applicants need to check 40 CFR 98 to confirm GWP values.

[2] For **HFCs** or **PFCs** describe the specific HFC or PFC compound and use a separate column for each individual compound.

[3] For each new compound, enter the appropriate GWP for each HFC or PFC compound from Table A-1 in 40 CFR 98.

[4] Green house gas emissions on a **mass basis** is the ton per year green house gas emission before adjustment with its GWP.

[5] **CO_2e** means Carbon Dioxide Equivalent and is calculated by multiplying the TPY mass emissions of the green house gas by its GWP.

Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will affect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

The **Process Summary** shall include a brief description of the facility and its processes.

Startup, Shutdown, and Maintenance (SSM) routine or predictable emissions: Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

El Paso Electric Company (EPE) owns and operates the Rio Grande Generating Station (Rio Grande) located in the city of Sunland Park in Doña Ana County, New Mexico. EPE currently operates three (3) natural gas-fired boilers and one (1) natural gas-fired turbine and ancillary equipment (cooling towers and piping) at Rio Grande Station. Boilers No. 6, 7, and 8 and turbine No. 9 operate under the New Mexico Operating Permit No. P127-R3 and Acid Rain Permit P127-AR3. Gas turbine No. 9 received approval for construction on June 2011 under NSR Permit No. 1554-M1. A detailed description of these existing units is presented in Table 3-1:

Table 3-1 Emissions Sources covered under existing Title V Permit: P127R3

Unit No.	Source Description	Make Model	Capacity
EPN-3	Unit # 6 Boiler	Babcock & Wilcox BW CNRB 465	610 MMBTU/hr
EPN-4	Unit # 7 Boiler	Babcock & Wilcox BW CSN 9926	590 MMBTU/hr
EPN-1	Unit # 8 Boiler	Babcock & Wilcox BW CNRB 298	1,535 MMBTU/hr
GT-9	Unit # 9 Turbine	GE LMS 100 PA	142,576 hp
F-1	Cooling Tower 6		33,600 gpm
F-1	Cooling Tower 7		24,000 gpm
F-1	Cooling Tower 8		55,000 gpm
CT-9	Cooling Tower 9	SPX – F434 A24 A4.002A	6,900 gpm
F-2	Piping Fugitives for Boilers 6, 7, 8		
FUG-9	Piping Fugitives for Turbine GT-9		

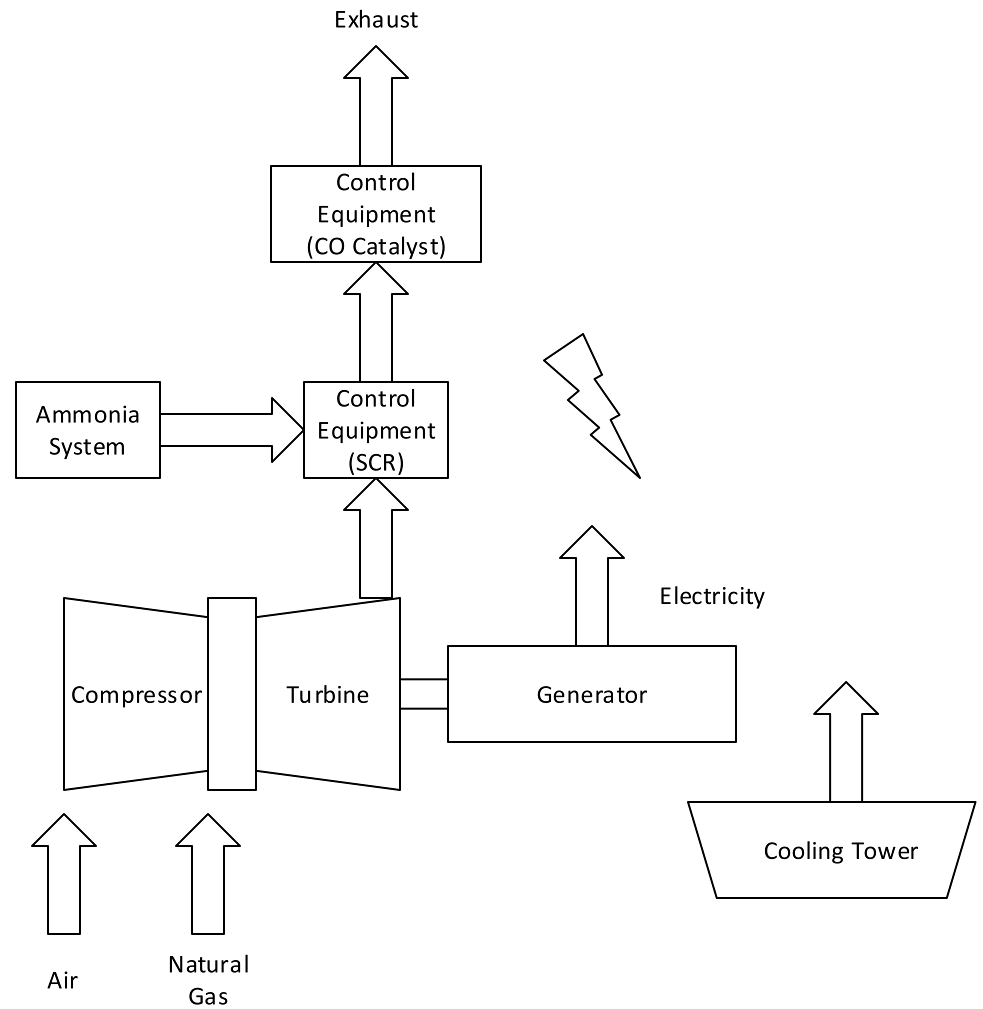
In this application, EPE respectfully requests the renewal of the existing Title V Operating Permit P127-R3, under 20.2.70.300.B.2 NMAC, and Acid Rain Permit P127-AR3.

Section 4

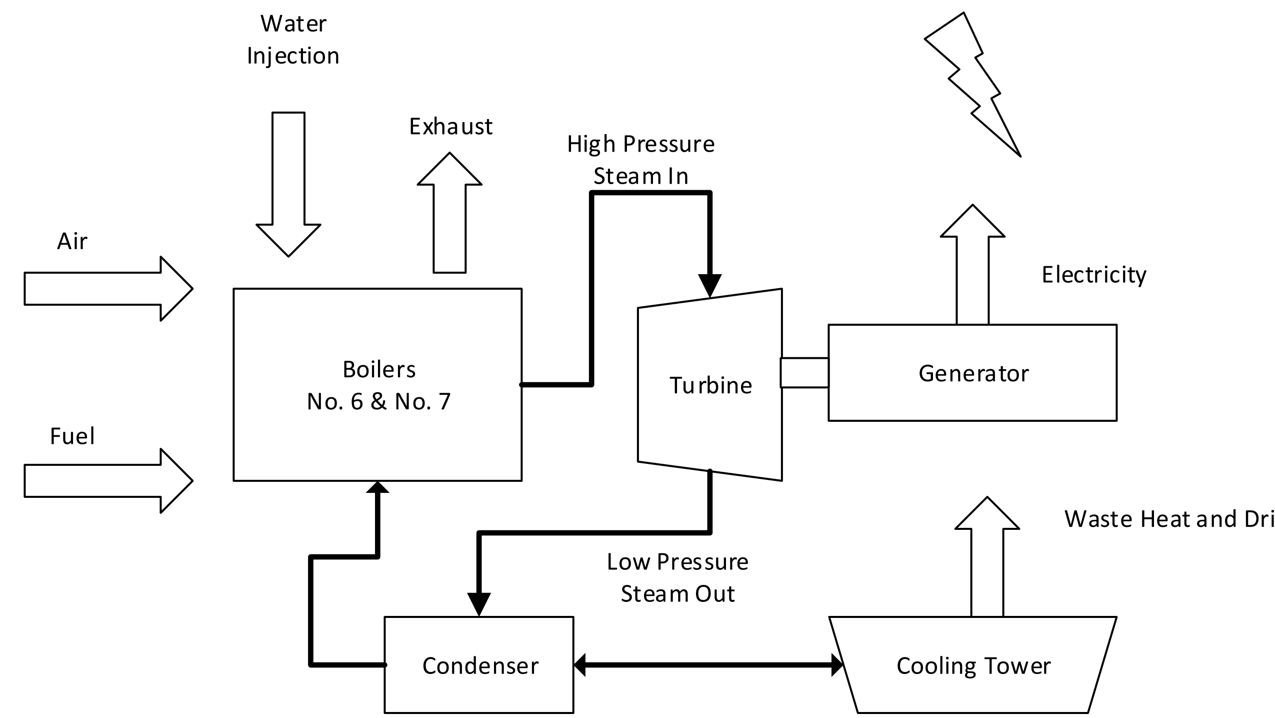
Process Flow Sheet

A **process flow sheet** and/or block diagram indicating the individual equipment, all emission points and types of control applied to those points. The unit numbering system should be consistent throughout this application.

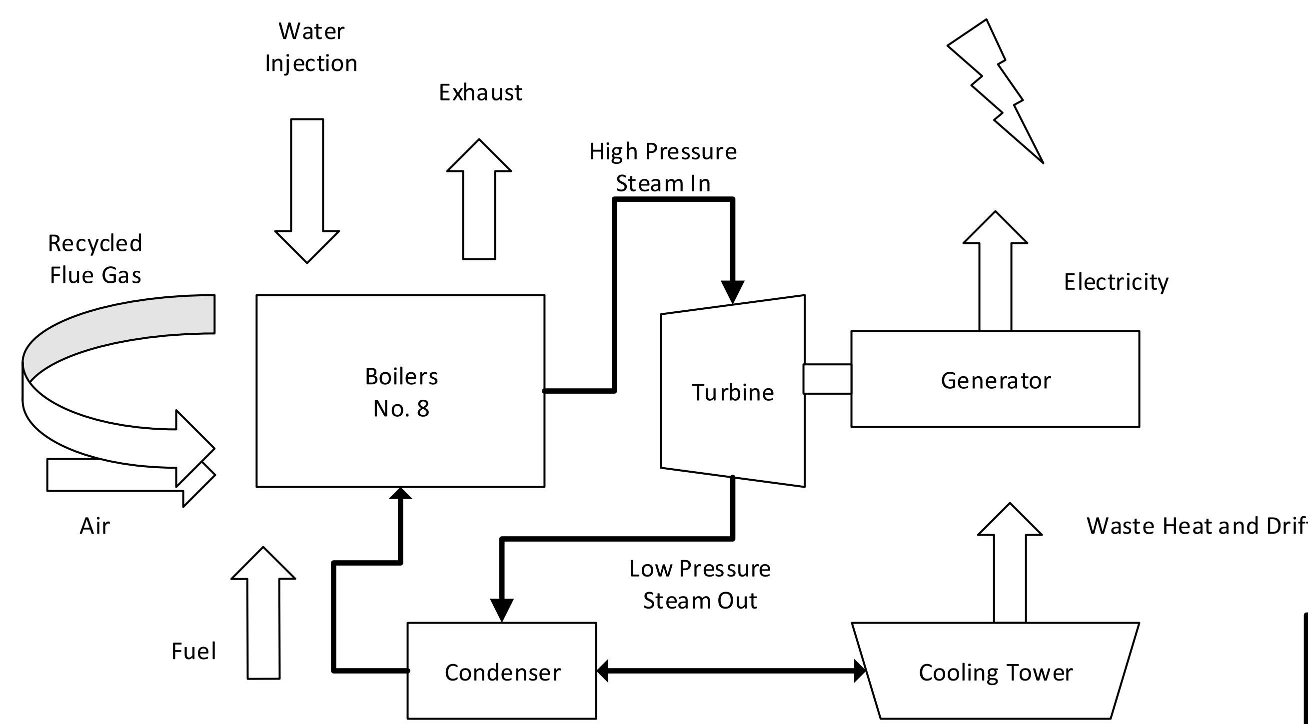
Refer to the attached document.



Emission Unit No. 9
GE LMS 100 Natural Gas-Fired Turbine Power Generating Unit



Emission Units No. 6 and No. 7
Boilers



Emission Unit No. 8
Boiler

El Paso Electric Company
Rio Grande Generating Station

Process Flow Diagrams

December 2013 Rev. 0

Section 5

Plot Plan Drawn To Scale

A **plot plan drawn to scale** showing emissions points, roads, structures, tanks, and fences of property owned, leased, or under direct control of the applicant. This plot plan must clearly designate the restricted area as defined in UA1, Section 1-D.12. The unit numbering system should be consistent throughout this application.

Refer to the attached document.

GENERAL NOTES

1. COORDINATES VALUES SHOWN UPON THIS DRAWING WERE DERIVED FROM SURVEY PERFORMED BY CUTTS LAND SURVEYING, INC DATED 04-08-2010
2. FOR LOCATION OF RIO GRANDE UNIT 9 EQUIPMENT AND STACK, SEE REFERENCE DRAWING #3
3. FOR EXISTING STACK LOCATION COORDINATES, SEE REFERENCE DRAWING #4

REFERENCE DRAWINGS

1. RIO GRANDE PLANT PLAN VIEW
THE ELECTRIC COMPANY - EL PASO ELECTRIC
ZEC DRAWING # M013729-SRWS001 S01 RP
2. EPEC RIO GRANDE CONTROL
CUTTS LAND SURVEYING, INC. JOB #090802
ZEC DRAWING # M013729-STWS001 SHT 1 REV P
3. RIO GRANDE UNIT 9, LMS100 EQUIPMENT GENERAL ARRANGEMENT
DRAWING # D013729-SRWL11001 SHT 1
4. EPEC RIO GRANDE CONTROL
CUTTS LAND SURVEYING, INC. JOB #100401
ZEC DRAWING # M013279-SRWS002 RP1

NO	REVISIONS	DATE	DRWN	CHKD	DSND	APPD
B	REVISED PER CLIENT COMMENTS					
A	ISSUED FOR PERMITTING					

The Electric Company®
El Paso Electric

ZACHRY

ZACHRY ENGINEERING CORPORATION - 1515 ARAPAHOE STREET, TOWER 1, SUITE 900, DENVER, CO 80202-4256
AMARILLO, TX CHARLOTTE, NC HOUSTON, TX MINNEAPOLIS, MN OMAHA, NE SAN ANTONIO, TX

RIO GRANDE UNIT 9
LMS100
OVERALL SITE PLAN

DRAWN	DESIGNED	CHECKED	CHECKED
5/10/10			5-10-10

APPROVED	DRAWING NUMBER	SHEET	REV
APPROVED 5/10/10	D013729 - SRWL10001	01	B

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Section 6

All Calculations

<u>Show all calculations</u> used to determine both the hourly and annual controlled and uncontrolled emission rates. All calculations shall be performed keeping a minimum of three significant figures. Document the source of each emission factor used (if an emission rate is carried forward and not revised, then a statement to that effect is required). If identical units are being permitted and will be subject to the same operating conditions, submit calculations for only one unit and a note specifying what other units to which the calculations apply. All formulas and calculations used to calculate emissions must be submitted. The "Calculations" tab in the UA2 has been provided to allow calculations to be linked to the emissions tables. Add additional "Calc" tabs as needed. If the UA2 or other spread sheets are used, all calculation spread sheet(s) shall be submitted electronically in Microsoft Excel compatible format so that formulas and input values can be checked. Format all spread sheets and calculations such that the reviewer can follow the logic and verify the input values. Define all variables. If calculation spread sheets are not used, provide the original formulas with defined variables. Additionally, provide subsequent formulas showing the input values for each variable in the formula. All calculations, including those calculations are imbedded in the Calc tab of the UA2 portion of the application, the printed Calc tab(s), should be submitted under this section.

Tank Flashing Calculations: The information provided to the AQB shall include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., NOI, permit, or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis. If Hysis is used, all relevant input parameters shall be reported, including separator pressure, gas throughput, and all other relevant parameters necessary for flashing calculation.

SSM Calculations: It is the applicant's responsibility to provide an estimate of SSM emissions or to provide justification for not doing so. In this Section, provide emissions calculations for Startup, Shutdown, and Routine Maintenance (SSM) emissions listed in the Section 2 SSM and/or Section 22 GHG Tables and the rational for why the others are reported as zero (or left blank in the SSM/GHG Tables). Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on calculating SSM emissions. If SSM emissions are greater than those reported in the Section 2, Requested Allowables Table, modeling may be required to ensure compliance with the standards whether the application is NSR or Title V. Refer to the Modeling Section of this application for more guidance on modeling requirements.

Glycol Dehydrator Calculations: The information provided to the AQB shall include the manufacturer's maximum design recirculation rate for the glycol pump. If GRI-Glycalc is used, the full input summary report shall be included as well as a copy of the gas analysis that was used.

Road Calculations: Calculate fugitive particulate emissions and enter haul road fugitives in Tables 2-A, 2-D and 2-E for:

1. If you transport raw material, process material and/or product into or out of or within the facility and have PER emissions greater than 0.5 tpy.
2. If you transport raw material, process material and/or product into or out of the facility more frequently than one round trip per day.

Significant Figures:

A. All emissions standards are deemed to have at least two significant figures, but not more than three significant figures.
B. At least 5 significant figures shall be retained in all intermediate calculations.
C. In calculating emissions to determine compliance with an emission standard, the following rounding off procedures shall be used:

- **(1)** If the first digit to be discarded is less than the number 5, the last digit retained shall not be changed;
- **(2)** If the first digit discarded is greater than the number 5, or if it is the number 5 followed by at least one digit other than the number zero, the last figure retained shall be increased by one unit; **and**
- **(3)** If the first digit discarded is exactly the number 5, followed only by zeros, the last digit retained shall be rounded upward if it is an odd number, but no adjustment shall be made if it is an even number.
- **(4)** The final result of the calculation shall be expressed in the units of the standard.

Control Devices: In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and (e) NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions. The applicant can indicate in this section of the application if they chose to not take credit for the reduction in emission rates. For notices of intent submitted under 20.2.73 NMAC, only uncontrolled emission rates can be considered to determine applicability unless the state or federal Acts require the control. This information is necessary to determine if federally enforceable conditions are necessary for the control device, and/or if the control device produces its own regulated pollutants or increases emission rates of other pollutants.

Boilers EPN-3, EPN-4, and EPN-1emission estimation sources:

- NOx emissions are estimated based on NM AQR limit 20.2.33.108 B.
- CO emissions are estimated based on from EPA AP-42 emission factor.
- VOC emissions are estimated based on EPA AP-42 emission factor.
- TSP, PM2.5, and PM10 emissions are estimated based on AB 2588.
- SO2 emissions were estimated assuming a sulfur content in gas of 0.0004 gr/dscf for long-term emissions and 0.0005 gr/dscf to calculate short-term emissions

GT-9 emission estimation sources:

- GE manufacturer provided emission factors.

EL PASO ELECTRIC COMPANY
RIO GRANDE GENERATING STATION PERMIT RENEWAL JUNE 2021
BOILER COMBUSTION EMISSIONS (NATURAL GAS FIRING)

Table 1- Natural Gas Fired Boiler Emissions

EPN	Description	Annual hours of operation (hr/yr)	Average Power Output (MMBTU/hr)	Maximum Power Output (MMBTU/hr)	Maximum Heat Input (MM scf/hr)[1]	Pollutant	Emission Factor (lb/MM BTU) or (lb/MM scf)	Maximum Hourly Emission Rate (lb/hr)	Annual Emission Rate (tpy)
EPN-3	Unit # 6 Boiler	8,760	610	610	0.661	NO_x [2]	0.3	183.00	801.54
		8,760	610	610	0.661	CO[3]	84	1400.00	243.02
		8,760	610	610	0.661	VOC[4]	5.5	3.63	15.91
		8,760	610	610	0.661	PM condensable	5.7	3.77	16.49
		8,760	610	610	0.661	PM filterable	1.9	1.26	5.50
		8,760	610	610	0.661	PM, PM_{10} [5]	7.6	5.02	21.99
		8,760	63	63	0.068	$PM_{2.5}$ [6]	7.6	0.51	2.25
		8,760	610	610	0.661	SO_2 [7,8]	0.13	0.08	0.31
EPN-4	Unit # 7 Boiler	8,760	590	590	0.639	NO_x [2]	0.3	176.99	775.19
		8,760	590	590	0.639	CO[3]	84	1400.00	235.03
		8,760	590	590	0.639	VOC[4]	5.5	3.51	15.39
		8,760	590	590	0.639	PM condensable	5.7	3.64	15.95
		8,760	590	590	0.639	PM filterable	1.9	1.21	5.32
		8,760	590	590	0.639	PM, PM_{10}, $PM_{2.5}$ [5]	7.6	4.86	21.27
		8,760	590	590	0.639	SO_2 [7,8]	0.13	0.08	0.30
EPN-1	Unit # 8 Boiler	8,760	1345	1535	1.662	NO_x [2]	0.3	460.50	1514.01
		8,760	1345	1535	1.662	CO[3]	84	1000.00	535.84
		8,760	1345	1535	1.662	VOC[4]	5.5	9.14	35.09
		8,760	1345	1535	1.662	PM condensable	5.7	9.47	36.36
		8,760	1345	1535	1.662	PM filterable	1.9	3.16	12.12
		8,760	1345	1535	1.662	PM, PM_{10}, $PM_{2.5}$ [5]	7.6	12.63	48.48
		8,760	1345	1535	1.662	SO_2 [7,8]	0.13	0.2137	0.68

[1] Calculations assume a Lower Heating Value (LHV) of natural gas of 924 BTU/scf

[2] NOx emissions derived from NM AQCR limit 20.2.33.108 B of 0.30 lb/MMBTU emission rate

[3] Long-term CO emissions (TPY) were estimated using EPA AP-42 Table 1.4-1. Emission factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion emission factor of 84.00 lb/MMscf

[4] VOC emission factor from AP-42 1.4 Natural Gas Combustion- Table 1.4-2 Emission Factors for Criteria Pollutants and GHG from Natural Gas Combustion

[5] AB 2588 Emmission factor for PM was used to estimate TSP, $PM_{2.5}$, and PM_{10} emissions

[6] $PM_{2.5}$ annual emission rate calculated assuming a maximum annual firing rate of 547,932 MMBTU/yr

[7] Long-term SO_2 emissions were calculated assuming a Sulfur content in gas of 0.0004 gr/dscf

[8] A sulfur content of 0.0005 gr/dscf was assumed to calculate SO_2 short-term emission rate

EL PASO ELECTRIC COMPANY
RIO GRANDE GENERATING STATION PERMIT RENEWAL JUNE 2021
TURBINE (GT-9) COMBUSTION EMISSIONS (NATURAL GAS FIRING)

Table 2- G.E. Performance Data

Parameter	Units	Base load condition (100%)
Hours of Operation	hrs[1]	8760
Turbine Fuel Consumption (HHV)	MMBTU/hr	826.2
Turbine Fuel Consumption	scf/hr	794,423.08
GGCV (HHV)	BTU/scf	1040

[1]Maximum hours of operation for the turbine

[2]Maximum hourly fuel consumption (HHV), provided by GE for Case 104 for 100% load, annual average temperature

Table 3- Criteria Pollutats- Emission Factors

Parameter	Units	Base load condition (100%)
NOx (Normal Operation- Uncontrolled)[3]	lb/hr	81.1
NOx (Normal Operation- Controlled)[1]	lb/hr	8.4
NOx (Startup)	lb/hr	18.04
NOx (Shutdown)	lb/hr	0.44
CO (Normal Operation- Uncontrolled)[3]	lb/hr	140.4
CO (Normal Operation- Controlled)[1]	lb/hr	21.11
CO (Startup)	lb/hr	30.25
CO (Shutdown)	lb/hr	2.97
VOC (Gas Turbine)[3]	lb/hr	2.26
VOC (Gas Turbine)[1]	lb/hr	2.1
PM (Gas Turbine)	lb/MMBTU[2]	0.004
	lb/hr	3.30
PM_{10} (Gas Turbine)	lb/MMBTU[2]	0.004
	lb/hr	3.30
$PM_{2.5}$ (Gas Turbine)	lb/MMBTU[2]	0.004
	lb/hr	3.30
SO_2 (Gas Turbine)	lb/hr	0.082

[1]Estimated turbine performance, Table 2-P *Turbine Emissions Calculations*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010- Case 104 (100% Load and Ambient Temperature Avg)

[2]Overall average PM emission rate in Table A-4 Filterable PM and Condensable PM Emission Data for LMS100 Turbines (simple cycle) firing natural gas of Appendix A- Letter to the NMED dated February 10, 2011.

[3]Estimated turbine performance, Table 2-P *Turbine Emissions Calculations*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010- Case 108 (100% Load and Ambient Temperature Low)

Table 4 - CO Startup and Shutdown PTE emissions

CO Startup Sequence	Time (mins)	CO Control	Emission rate (lb/hr)[2]	Emissions (lbs)
First fire to stable GT emissions[1]	7	0%		10.21
Balance of startup period	20	Full	22.69	7.56
Total for one startup	27	-		17.77
Balance of hour	33	Full	22.69	12.48
Total for one startup plus balance hour	60	-		30.25

CO Shutdown Sequence	CO Uncontrolled (lb/event)	CO Control[3] (%)	CO Controlled (lb/event)	Emissions (lbs)
Total for one shutdown	13.21	77.5%	2.97	2.97

Number of startup/shutdowns per year	Emission Rate (lb/startup)	Annual Emissions Startup (tpy)	Emission Rate (lb/shutdown)	Annual Emissions Shutdown (tpy)	Total Annual SU/SD (tpy)
417	17.77	3.71	2.97	0.62	4.33

[1]CO Emissions from first fire to stable GT operations- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

[2]Maximum Controlled CO emissions rate at stable GT operation- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

[3]Minimum expected CO control efficiency- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

Table 5- NOx Startup and Shutdown PTE emissions

NOx Startup Sequence	Time (mins)	NOx Control (%)	Emission rate (lb/hr)[2]	Emissions (lbs)
First fire to stable GT emissions[1]	7	0		3.01
Balance of startup period	20	44%	45.09	15.03
Total for one startup	27	-	-	18.04
Balance of hour	33	Full	9.08	4.99
Total for one startup plus balance hour	60	-		23.03

NOx Shutdown Sequence	NOx Uncontrolled (lb/event)[4]	NOx Control (%)[3]	NOx Controlled (lb/event)	Emissions (lbs)
Total for one shutdown	3.97	88.80%	0.44	0.44

Number of startup/shutdowns per year	Emission Rate (lb/startup)	Annual Emissions Startup (tpy)	Emission Rate (lb/shutdown)	Annual Emissions Shutdown (tpy)	Total Annual SU/SD (tpy)
417	18.04	3.76	0.44	0.09	3.85

[1]NOx Emissions from first fire to stable GT operations- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

[2]Maximum Controlled NOx emissions rate at stable GT operation- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

[3]Expected NOx control efficiency- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

[4]GT NOx emissions from initiation to shutdown to end of combustion- Table 2-R *Startup, Shutdown and malfunction PTE Emissions*- Air Quality Permit application, New Electric Generating Unit El Paso Electric Company, June 2010

Table 6- Uncontrolled GT-9 Emission Rate Summary

	NOx[1]	CO[1]	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
Long-Term Emission Rate (tpy)	330.30	481.50	9.20	14.48	14.48	14.48	0.40
Short-Term Emission Rate (lb/hr)	81.10	140.40	2.26	3.30	3.30	3.30	0.082

[1]Estimated turbine performance, Table 2-P *Turbine Emissions Calculations*- Air Quality Permit application, New Electric Generating Unit, El Paso Electric Company, June 2010

Table 7- Controlled GT-9 Emission Rate Summary

	NOx	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2
Long-Term Emission Rate (tpy)	39.60	94.10	9.20	14.48	14.48	14.48	0.40
Short-Term Emission Rate (lb/hr)	23.03	30.25	2.26	3.30	3.30	3.30	0.082

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COOLING TOWER EMISSIONS

Table 8- Calculation of PM Emissions

EPN	Description	Circulation Rate (gpm)	Drift (%)	TDS (ppmw)	Emission Factor ($lb/10^3$ gal)	Operating Hours (hr/yr)	Annual PM Emission Rate (lb/hr)	Annual PM Emission Rate (tpy)
F1-6	Cooling Tower 6	33,600	0.005	9000	0.00375	8760	7.57	33.14
F1-7	Cooling Tower 7	24,000	0.005	9000	0.00375	8760	5.40	23.67
F1-8	Cooling Tower 8	55,000	0.002	9000	0.00150	8760	4.95	21.70
CT-9	Cooling Tower 9	6,900	0.001	9000	0.00075	8760	0.31	1.36

Table 9- Calculation of PM_{10} Emissions

EPN	Description	% PM that Evaporates to PM_{10}	Annual PM Emission Rate (tpy)	Hourly PM Emission Rate (lb/hr)	Operating Hours (hr/yr)	Hourly PM_{10} Emission Rate (lb/hr)	Annual PM_{10} Emission Rate (tpy)
F1-6	Cooling Tower 6	6.4	33.14	7.57	8760	0.48	2.12
F1-7	Cooling Tower 7	6.4	23.67	5.40	8760	0.35	1.51
F1-8	Cooling Tower 8	6.4	21.70	4.95	8760	0.32	1.39
CT-9	Cooling Tower 9	6.4	1.36	0.31	8760	0.02	0.09

Table 10- Calculation of $PM_{2.5}$ Emissions

EPN	Description	% PM that Evaporates to $PM_{2.5}$	Annual PM Emission Rate (tpy)	Hourly PM Emission Rate (lb/hr)	Operating Hours (hr/yr)	Hourly $PM_{2.5}$ Emission Rate (lb/hr)	Annual $PM_{2.5}$ Emission Rate (tpy)
F1-6	Cooling Tower 6	0.13	33.14	7.57	8760	0.01	0.04
F1-7	Cooling Tower 7	0.13	23.67	5.40	8760	0.01	0.03
F1-8	Cooling Tower 8	0.13	21.70	4.95	8760	0.01	0.03
CT-9	Cooling Tower 9	0.13	1.36	0.31	8760	0.0004	0.0018

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RIO GRANDE GENERATING STATION PERMIT RENEWAL JUNE 2021
SPECIATED BOILER COMBUSTION EMISSIONS (NATURAL GAS FIRING)

Table 11- Boiler Speciated HAP Emissions

EPN	Description	Annual hours of operation (hr/yr)	Average Power Output (MMBTU/hr)	Maximum Power Output (MMBTU/hr)	Heating Value (Btu/scf)	Pollutant	Emission Factor (lb/MMscf)[1]	Maximum Hourly Emission Rate (lb/hr)	Annual Emission Rate (tpy)
EPN-3	Unit # 6 Boiler	8,760	610	610	924	Acetaldehyde	0.0009	0.00059	0.0026
		8,760	610	610	924	Acrolein	0.0008	0.00053	0.0023
		8,760	610	610	924	Benzene	0.0017	0.00112	0.0049
		8,760	610	610	924	Ethylbenzene	0.0020	0.00132	0.0058
		8,760	610	610	924	Formaldehyde	0.0036	0.00238	0.0104
		8,760	610	610	924	Hexane	0.0013	0.00086	0.0038
		8,760	610	610	924	Naphthalene	0.0003	0.00020	0.0009
		8,760	610	610	924	Toluene	0.0078	0.00515	0.0226
		8,760	610	610	924	Xylenes	0.0058	0.00383	0.0168
EPN-4	Unit # 7 Boiler	8,760	590	590	924	Acetaldehyde	0.0009	0.00057	0.0025
		8,760	590	590	924	Acrolein	0.0008	0.0005	0.0022
		8,760	590	590	924	Benzene	0.0017	0.0011	0.0048
		8,760	590	590	924	Ethylbenzene	0.0020	0.0013	0.0056
		8,760	590	590	924	Formaldehyde	0.0036	0.0023	0.0101
		8,760	590	590	924	Hexane	0.0013	0.00083	0.0036
		8,760	590	590	924	Naphthalene	0.0003	0.0002	0.0008
		8,760	590	590	924	Toluene	0.0078	0.0050	0.0218
		8,760	590	590	924	Xylenes	0.0058	0.0037	0.0162
EPN-1	Unit # 8 Boiler	8,760	1345	1535	924	Acetaldehyde	0.0009	0.0015	0.0057
		8,760	1345	1535	924	Acrolein	0.0008	0.0013	0.0051
		8,760	1345	1535	924	Benzene	0.0017	0.0028	0.0108
		8,760	1345	1535	924	Ethylbenzene	0.0020	0.0033	0.0128
		8,760	1345	1535	924	Formaldehyde	0.0036	0.0060	0.0230
		8,760	1345	1535	924	Hexane	0.0013	0.0022	0.0083
		8,760	1345	1535	924	Naphthalene	0.0003	0.0005	0.0019
		8,760	1345	1535	924	Toluene	0.0078	0.0130	0.0497
		8,760	1345	1535	924	Xylenes	0.0058	0.0096	0.0370

[1] *AB 2588 Factors for external combustion sources >100 MMBtu/hr (lb/10^6 ft^3)*

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RIO GRANDE GENERATING STATION PERMIT RENEWAL JUNE 2021
SPECIATED TURBINE COMBUSTION EMISSIONS (NATURAL GAS FIRING)

Table 12- Turbine Speciated HAP Emissions

EPN	Description	Annual hours of operation (hr/yr)	Average Power Output (MMBTU/hr)	Maximum Power Output (MMBTU/hr)	Pollutant	Emission Factor (lb/MMBTU)[1]	Maximum Hourly Emission Rate (lb/hr)	Annual Emission Rate (tpy)
GT-9	Unit 9	8,760	826	826	Acetaldehyde	4.0E-05	0.03305	0.1448
		8,760	826	826	Acrolein	6.4E-06	0.00529	0.0232
		8,760	826	826	Benzene	9.1E-07	0.00075	0.0033
		8,760	826	826	Ethylbenzene	3.2E-05	0.02644	0.1158
		8,760	826	826	Formaldehyde	2.0E-05	0.01652	0.0724
		8,760	826	826	Naphthalene	1.3E-06	0.00107	0.0047
		8,760	826	826	Toluene	1.3E-04	0.10741	0.4704
		8,760	826	826	Xylenes	6.4E-05	0.05288	0.2316
		8,760	826	826	PAH	2.2E-06	0.00182	0.0080
		8,760	826	826	Propylene Oxide	2.9E-05	0.02396	0.1049

[1] GE Turbine Emission Calculations Table 2-P

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FUGITIVE EMISSION CALCULATIONS

Table 13- Calculation of VOC, HAPs and Cl2 Emissions from Piping components

EPN	Description	Pollutant	Source Type	Fluid State	Count	Emission Factor (lb/hr-component)[1]	Hourly ER (lb/hr)	Annual ER (tpy)
F-2	Piping fugitives for boilers 6, 7, 8	TOC	Valves	Gas/Vapor	700	0.00992	6.94	30.41
			Unions	Gas/Vapor	149	0.00086	0.13	0.56
			Taps	Gas/Vapor	446	0.0194	8.65	37.90
			Others	Gas/Vapor	12	0.0194	0.23	1.02
			Flanges	Gas/Vapor	1644	0.00086	1.41	6.19
						Total TOC	17.37	76.09
		VOC				**non-methane/non-ethane VOC[2]**	0.68	2.97
		HAPs				**HAPs[3]**	0.036	0.02
		Cl_2[4]	Valves	Gas/Vapor	24	0.0089	0.21	0.94
			Flanges	Gas/Vapor	84	0.0029	0.24	1.07
						Total Cl_2	0.46	2.00
FUG-9	Piping fugitives for 9	TOC	Valves	Gas/Vapor	19	0.00992	0.19	0.83
			Flanges	Gas/Vapor	18	0.00086	0.02	0.07
			Taps/Drains	Gas/Vapor	3	0.0194	0.06	0.25
						Total TOC	0.26	1.15
		VOC				**non-methane/non-ethane VOC[2]**	0.010	0.045
		HAPs				**HAPs[3]**	0.00	0.002
		Cl_2[4]	Valves	Gas/Vapor	6	0.0089	0.05	0.23
			Flanges	Gas/Vapor	21	0.0029	0.06	0.27
						Total Cl_2	0.11	0.50
		NH_3[4]	Valves	Gas/Vapor	15	0.0089	0.13	0.58
			Flanges	Gas/Vapor	11	0.0029	0.03	0.14
			Pumps	Light Liquid	0	0.005	0.00	0.00
						Total NH_3	0.17	0.72

[1] VOC emission factors from Table 2-4 Oil and Gas Production average Emission Factors, November 1995

[2] The natural gas composition shows methane at 92.08% weight and ethane at 4.02%, leaving 3.9% as non-methane/non-ethane VOC

[3] HAP percentage is assumed to be 0.21% of the total TOC emissions

[4] SOCMI without Ethylene emission factors for valves and flanges used to estimate Cl_2 and NH_3 fugitive emissions

Section 6.a

Green House Gas Emissions

(Submitting under 20.2.70, 20.2.72 20.2.74 NMAC)

Title V (20.2.70 NMAC), Minor NSR (20.2.72 NMAC), and PSD (20.2.74 NMAC) applicants must estimate and report greenhouse gas (GHG) emissions to verify the emission rates reported in the public notice, determine applicability to 40 CFR 60 Subparts, and to evaluate Prevention of Significant Deterioration (PSD) applicability. GHG emissions that are subject to air permit regulations consist of the sum of an aggregate group of these six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Calculating GHG Emissions:

1. Calculate the ton per year (tpy) GHG mass emissions and GHG CO_2e emissions from your facility.
2. GHG mass emissions are the sum of the total annual tons of greenhouse gases without adjusting with the global warming potentials (GWPs). GHG CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its GWP found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. Emissions from routine or predictable start up, shut down, and maintenance must be included.
4. Report GHG mass and GHG CO_2e emissions in Table 2-P of this application. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).
5. All Title V major sources, PSD major sources, and all power plants, whether major or not, must calculate and report GHG mass and CO2e emissions for each unit in Table 2-P.
6. For minor source facilities that are not power plants, are not Title V, and are not PSD there are three options for reporting GHGs in Table 2-P: 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHGs as a second separate unit; 3) or check the following ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases:

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of air permit regulations is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7 NMAC, 20.2.74.7 NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Metric to Short Ton Conversion:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions)

Table 14- Boiler 6 Performance Data

Parameter	Units	Base load condition (100%)
Fuel Consumption (HHV)	MMBTU/hr	610
Fuel Consumption	scf/hr	5865
GGCV (HHV)	BTU/scf	1040

Table 15- Total Potential Heat Input from the combustion turbine

Scenario	Hrs. of Operation	Heat Input (MMBTU/hr)	Total Annual Heat Input (MMBTU)	Total Annual Fuel Consumption (hscf)
Normal Operation	8760	610	5,343,600	51,380,769

Table 16- Long Term Emissions (tpy)

Pollutant	Emission Factors		Total Annual Heat Input (MMBTU)	Emissions	
	(kg/MMBTU) [1,2,3]	(lb/MMBTU) [1,2,3]		lb/yr	tpy
CO_2	53.06	117.00	5,343,600	625,186,772	312,593
CH_4	0.001	0.0022	5,343,600	11,783	5.89
N_2O	0.0001	0.00022	5,343,600	1,178	0.59
CO_{2e}	53.11	117.11	5,343,600	625,775,904	312,888

[1] Emission factor from Table C-1 of 40 CFR Part 98, Subpart C for weighted U.S. Average of natural gas. Converted to lb by multiplying by 2.205 lb/kg

[2] Emission factors from Table C-2 (CH_4 and N_2O) of 40 CFR Part 98, Subpart C. Converted to lb by multiplying by 2.205 lb/kg

[3] Global warming potentials obtained from Table A-1 to Subpart 98; CH_4 = 25; N_2O = 298

Table 17- Boiler 7 Performance Data

Parameter	Units	Base load condition (100%)
Fuel Consumption (HHV)	MMBTU/hr	590
Fuel Consumption	scf/hr	5673
GGCV (HHV)	BTU/scf	1040

Table 18- Total Potential Heat Input from the combustion turbine

Scenario	Hrs. of Operation	Heat Input (MMBTU/hr)	Total Annual Heat Input (MMBTU)	Total Annual Fuel Consumption (hscf)
Normal Operation	8760	590	5,168,400	49,696,154

Table 19- Long Term Emissions (tpy)

Pollutant	Emission Factors		Total Annual Heat Input (MMBTU)	Emissions	
	(kg/MMBTU) [1,2,3]	(lb/MMBTU) [1,2,3]		lb/yr	tpy
CO_2	53.06	117.00	5,168,400	604,688,845	302,344
CH_4	0.001	0.0022	5,168,400	11,396	5.70
N_2O	0.0001	0.00022	5,168,400	1,140	0.57
CO_{2e}	53.11	117.11	5,168,400	605,258,661	302,629

[1] Emission factor from Table C-1 of 40 CFR Part 98, Subpart C for weighted U.S. Average of natural gas. Converted to lb by multiplying by 2.205 lb/kg

[2] Emission factors from Table C-2 (CH_4 and N_2O) of 40 CFR Part 98, Subpart C. Converted to lb by multiplying by 2.205 lb/kg

[3] Global warming potentials obtained from Table A-1 to Subpart 98; CH_4 = 25; N_2O = 298

Table 20- Boiler 8 Performance Data

Parameter	Units	Base load condition (100%)
Fuel Consumption (HHV)	MMBTU/hr	1535
Fuel Consumption	scf/hr	14,760
GGCV (HHV)	BTU/scf	1040

Table 21- Total Potential Heat Input from the combustion turbine

Scenario	Hrs. of Operation	Heat Input (MMBTU/hr)	Total Annual Heat Input (MMBTU)	Total Annual Fuel Consumption (hscf)
Normal Operation	8760	1535	13,446,600	129,294,231

Table 22- Long Term Emissions (tpy)

Pollutant	Emission Factors		Total Annual Heat Input (MMBTU)	Emissions	
	(kg/MMBTU) [1,2,3]	(lb/MMBTU) [1,2,3]		lb/yr	tpy
CO_2	53.06	117.00	13,446,600	1,573,215,894	786,608
CH_4	0.001	0.0022	13,446,600	29,650	14.82
N_2O	0.0001	0.00022	13,446,600	2,965	1.48
CO_{2e}	53.11	117.11	13,446,600	1,574,698,382	787,349

[1] Emission factor from Table C-1 of 40 CFR Part 98, Subpart C for weighted U.S. Average of natural gas. Converted to lb by multiplying by 2.205 lb/kg

[2] Emission factors from Table C-2 (CH_4 and N_2O) of 40 CFR Part 98, Subpart C. Converted to lb by multiplying by 2.205 lb/kg

[3] Global warming potentials obtained from Table A-1 to Subpart 98; CH_4 = 25; N_2O = 298

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GHG EMISSION CALCULATIONS

Table 23- Combustion Turbine Performance Data

Parameter	Units	Base load condition (100%)
Turbine Fuel Consumption (HHV)	MMBTU/hr	826.2
Turbine Fuel Consumption	scf/hr	7944
GGCV (HHV)	BTU/scf	1040

Table 24- Total Potential Heat Input from the combustion turbine

Scenario	Hrs. of Operation[1]	Heat Input (MMBTU/hr)[2]	Total Annual Heat Input (MMBTU)	Total Annual Fuel Consumption (hscf)
Normal Operation	8760	826.2	7,237,512	69,591,462

[1] Estimated hours of operation for the turbine

[2] Maximum hourly fuel consumption (HHV), provided by GE for Case 104 for 100% load, annual average temperature

Table 25- Long Term Emissions (tpy)

Pollutant	Emission Factors		Total Annual Heat Input (MMBTU)	Emissions	
	(kg/MMBTU)[3,4,5]	(lb/MMBTU)[3,4,5]		lb/yr	tpy
CO_2	53.06	117.00	7,237,512	846,769,363	423,385
CH_4	0.001	0.0022	7,237,512	15,959	7.98
N_2O	0.0001	0.00022	7,237,512	1,596	0.80
CO_{2e}	53.11	117.11	7,237,512	847,567,298	423,784

[3] Emission factor from Table C-1 of 40 CFR Part 98, Subpart C for weighted U.S. Average of natural gas. Converted to lb by multiplying by 2.205 lb/kg

[4] Emission factors from Table C-2 (CH_4 and N_2O) of 40 CFR Part 98, Subpart C. Converted to lb by multiplying by 2.205 lb/kg

[5] Global warming potentials obtained from Table A-1 to Subpart 98; CH_4 = 25; N_2O = 298

Section 7

Information Used To Determine Emissions

Information Used to Determine Emissions shall include the following:

☒ If manufacturer data are used, include specifications for emissions units and control equipment, including control efficiencies specifications and sufficient engineering data for verification of control equipment operation, including design drawings, test reports, and design parameters that affect normal operation.

☐ If test data are used, include a copy of the complete test report. If the test data are for an emissions unit other than the one being permitted, the emission units must be identical. Test data may not be used if any difference in operating conditions of the unit being permitted and the unit represented in the test report significantly effect emission rates.

☒ If the most current copy of AP-42 is used, reference the section and date located at the bottom of the page. Include a copy of the page containing the emissions factors, and clearly mark the factors used in the calculations.

☐ If an older version of AP-42 is used, include a complete copy of the section.

☒ If an EPA document or other material is referenced, include a complete copy.

☒ Fuel specifications sheet.

☐ If computer models are used to estimate emissions, include an input summary (if available) and a detailed report, and a disk containing the input file(s) used to run the model. For tank-flashing emissions, include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., permit or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis.

Please refer to attachments below.

Table 2-P
Turbine Emissions Calculations

Global Parameters

Natural gas heat content	924	Btu/ft^3, LHV (From natural gas analysis dated Jan 14, 2009. Values are typical for EPEC.)
Natural gas heat content	1,024	Btu/ft^3, HHV (From natural gas analysis dated Jan 14, 2009. Values are typical for EPEC.)
Natural gas HHV/LHV ratio	1.11	
Stack diameter	13.5	ft
Stack height	90	ft
Controlled NOx emissions	2.8	ppmvd @ 15% O2
Controlled VOC emissions	2	ppmvd @ 15% O2
Maximum fuel sulfur content	0.0005	gr H2S/dscf (From natural gas analysis dated Jan 14, 2009. The value is the Detection Limit x 1.5)
Average fuel sulfur content	0.0004	gr H2S/dscf (From natural gas analysis dated Jan 14, 2009. The value is the Detection Limit x 1.25)
Filterable PM10 emissions	2.1	lb/hr (from GE letter which represents a conservatively high filterable to total particulate ratio compared to the ratio of AP-42 total and filterable Particulate matter emission factors)
Annual hours of normal operation	8503	hours

Case[1]	Load	Ambient Temperature Scenario	Ambient Temperature[2] (°F)[3]	Humidity (%)[4]	Fuel Flow, LHV (MMBtu/hr)[5]	Fuel Flow, HHV (MMBtu/hr)	Exhaust Temperature (°F)	Exhaust Mol Wt (lb/lbmol)	Exhaust Flow (lb/hr)	Exhaust Flow (acfs)[6]	Stack Diameter[7] (feet)	Exit Velocity (ft/sec)[8]	Dry Exhaust Flow (lb/hr)	Dry Exhaust Mol Wt (lb/lbmol)	Dry Standard Exhaust Flow (dscfs)[9]	Stack Height (feet)	Exhaust Temperature (°K)[10]	Diameter (m)[11]	Velocity (m/sec)[12]
100	100%	High	105.0	8.6	706.1	782.5	789.7	28.11	1,481,270	13,358	13.5	93.3	1,374,038	29.37	5,011	90	693.9	4.11	28.4
101	75%	High	105.0	8.6	563.7	624.7	790.7	28.17	1,270,113	11,437	13.5	79.9	1,184,838	29.34	4,325	90	694.5	4.11	24.4
102	50%	High	105.0	8.6	427.5	473.8	829.7	28.21	1,023,277	9,489	13.5	66.3	958,078	29.31	3,500	90	716.2	4.11	20.2
103	25%	High	105.0	8.6	279.3	309.5	849.7	28.31	771,364	7,238	13.5	50.6	728,992	29.26	2,668	90	727.3	4.11	15.4
104	100%	Average	64.0	25.0	745.5	826.2	772.8	28.13		0	13.5	0.0	1,451,055	29.37	5,292	90	684.5	4.11	0.0
105	75%	Average	64.0	25.0	592.5	656.6	768.1	28.21	1,343,066	11,859	13.5	82.9	1,256,233	29.33	4,587	90	681.9	4.11	25.3
106	50%	Average	64.0	25.0	449.2	497.8	817.0	28.27	1,070,543	9,810	13.5	68.5	1,005,939	29.31	3,675	90	709.1	4.11	20.9
107	25%	Average	64.0	25.0	292.6	324.3	850.0	28.37	793,375	7,431	13.5	51.9	752,208	29.26	2,753	90	727.5	4.11	15.8
108	100%	Low	15.0	20.0	801.4	888.1	751.2	28.19	1,674,252	14,589	13.5	101.9	1,561,484	29.37	5,694	90	672.5	4.11	31.1
109	75%	Low	15.0	20.0	632.2	700.6	738.0	28.29	1,448,787	12,443	13.5	86.9	1,362,656	29.33	4,976	90	665.2	4.11	26.5
110	50%	Low	15.0	20.0	478.1	529.8	798.3	28.34	1,137,032	10,240	13.5	71.5	1,073,435	29.31	3,922	90	698.7	4.11	21.8
111	25%	Low	15.0	20.0	308.9	342.3	850.2	28.44	818,053	7,645	13.5	53.4	778,614	29.27	2,849	90	727.6	4.11	16.3

Maximum Hourly Emissions, Normal Operations (lb/hr)
Maximum Annual Emissions, Normal Operations at 8503 hours per year (tpy)
Maximum Annual Emissions, Normal Operations at 8760 hours per year (tpy)
Maximum Annual Emissions, Normal Operations and Startup/Shutdown combined (tpy)

Notes can be found on the last page of Table 2-P

Table 2-P
Turbine Emissions Calculations

Case[1]	Load	Ambient Temperature Scenario	Uncontrolled NO_X[13,14] ppm[15]	Uncontrolled NO_X[13,14] (lb/hr)[16]	Uncontrolled NO_X[13,14] (tpy)[17]	Controlled NO_X[13,14] ppm	Controlled NO_X[13,14] (lb/hr)	Controlled NO_X[13,14] (tpy)	Uncontrolled CO[14,18] ppm	Uncontrolled CO[14,18] (lb/hr)	Uncontrolled CO[14,18] (tpy)	Controlled CO[14] ppm	Controlled CO[14] (lb/hr)	Controlled CO[14] (tpy)	Uncontrolled VOC[14,19] ppm	Uncontrolled VOC[14,19] (lb/hr)	Uncontrolled VOC[14,19] (tpy)	Controlled VOC[14] ppm	Controlled VOC[14] (lb/hr)	Controlled VOC[14] (tpy)	SO_2[20] (lb/hr)	SO_2[20] (tpy)	Filterable PM[21] (lb/hr)	Filterable PM[21] (tpy)	Filterable PM_{10}[22] (lb/hr)	Filterable PM_{10}[22] (tpy)
100	100%	High	25.0	71.44	303.70	2.8	8.00	34.00	51.4	97.69	415.31	11.5	20.00	85.01	2.0	1.99	8.45	2.0	1.99	8.45	0.09	0.33	2.1	8.93	2.1	8.93
101	75%	High	25.0	56.99	242.31	2.8	6.38	27.13	53.6	81.23	345.36	11.5	15.95	67.82	2.0	1.58	6.73	2.0	1.59	6.74	0.07	0.26	2.1	8.93	2.1	8.93
102	50%	High	25.0	43.21	183.70	2.8	4.84	20.56	75.0	86.15	366.28	11.5	12.09	51.41	2.0	1.20	5.11	2.0	1.20	5.11	0.06	0.20	2.1	8.93	2.1	8.93
103	25%	High	25.1	28.20	119.90	2.8	3.15	13.40	148.3	111.10	472.35	11.5	7.88	33.50	4.4	1.71	7.29	2.0	0.78	3.33	0.04	0.13	2.1	8.93	2.1	8.93
104	100%	Average	25.0	75.42	320.64	2.8	8.44	35.90	54.8	109.92	467.33	11.5	21.11	89.76	2.0	2.10	8.93	2.0	2.10	8.92	0.10	0.35	2.1	8.93	2.1	8.93
105	75%	Average	25.0	59.90	254.67	2.8	6.71	28.51	51.0	81.31	345.68	11.5	16.77	71.28	2.0	1.67	7.09	2.0	1.67	7.08	0.08	0.27	2.1	8.93	2.1	8.93
106	50%	Average	25.0	45.40	193.01	2.8	5.08	21.61	62.5	75.44	320.71	11.5	12.71	54.02	2.0	1.26	5.36	2.0	1.26	5.37	0.06	0.21	2.1	8.93	2.1	8.93
107	25%	Average	25.0	29.54	125.61	2.8	3.30	14.05	110.5	86.66	368.45	11.5	8.26	35.12	2.9	1.19	5.05	2.0	0.82	3.49	0.04	0.14	2.1	8.93	2.1	8.93
108	100%	Low	25.0	81.07	344.68	2.8	9.08	38.59	65.1	140.44	597.07	11.5	22.69	96.48	2.0	2.26	9.59	2.0	2.26	9.59	0.10	0.37	2.1	8.93	2.1	8.93
109	75%	Low	25.0	63.92	271.74	2.8	7.16	30.42	53.4	90.88	386.36	11.5	17.89	76.06	2.0	1.78	7.56	2.0	1.78	7.56	0.08	0.29	2.1	8.93	2.1	8.93
110	50%	Low	25.0	48.32	205.43	2.8	5.41	23.00	61.7	79.19	336.67	11.5	13.52	57.49	2.0	1.35	5.72	2.0	1.34	5.71	0.06	0.22	2.1	8.93	2.1	8.93
111	25%	Low	25.0	31.19	132.61	2.8	3.49	14.83	100.5	83.24	353.90	11.5	8.72	37.09	2.6	1.12	4.76	2.0	0.87	3.69	0.04	0.14	2.1	8.93	2.1	8.93
Maximum Hourly Emissions, Normal Operations (lb/hr)				81.1			**9.1**			140.4			**22.69**			2.3			**2.3**		**0.1**		**2.1**		**2.1**	
Maximum Annual Emissions, Normal Operations at 8503 hours per year (tpy)					320.6			**35.9**			467.3			**89.8**			8.9			**8.9**		**0.3**		**8.9**		**8.9**
Maximum Annual Emissions, Normal Operations at 8760 hours per year (tpy)					330.3			37.0			481.5			92.5			9.2			9.2		0.4		9.2		9.2
Maximum Annual Emissions, Normal Operations and Startup/Shutdown combined (tpy)								**36.6**						**94.1**						9.2		0.4		9.2		9.2

Notes can be found on the last page of Table 2-P

Table 2-P
Turbine Emissions Calculations

Case[1]	Load	Ambient Temperature Scenario	Filterable $PM_{2.5}$[23]		Condensable PM from control devices	Condensable PM from Gas Turbine	Condensable PM		Condensable PM_{10}		Condensable $PM_{2.5}$		Total PM		Total PM_{10}		Total $PM_{2.5}$		NH_3[24]		
			(lb/hr)	(tpy)	(lb/hr)	(lb/hr)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	ppm	(lb/hr)	(tpy)
100	100%	High	2.1	8.93	0.4	3.4	3.83	16.27	3.83	16.27	3.83	16.27	5.93	25.20	5.93	25.20	5.93	25.20	5.0	5.28	22.44
101	75%	High	2.1	8.93	0.4	3.4	3.78	16.06	3.78	16.06	3.78	16.06	5.88	24.98	5.88	24.98	5.88	24.98	5.0	4.21	17.90
102	50%	High	2.1	8.93	0.4	3.4	3.78	16.08	3.78	16.08	3.78	16.08	5.88	25.01	5.88	25.01	5.88	25.01	5.0	3.19	13.57
103	25%	High	2.1	8.93	0.3	3.4	3.70	15.74	3.70	15.74	3.70	15.74	5.80	24.67	5.80	24.67	5.80	24.67	5.0	2.08	8.84
104	100%	Average	2.1	8.93	0.4	3.4	3.80	16.13	3.80	16.13	3.80	16.13	5.90	25.06	5.90	25.06	5.90	25.06	5.0	5.57	23.69
105	75%	Average	2.1	8.93	0.3	3.4	3.73	15.88	3.73	15.88	3.73	15.88	5.83	24.81	5.83	24.81	5.83	24.81	5.0	4.43	18.82
106	50%	Average	2.1	8.93	0.4	3.4	3.78	16.05	3.78	16.05	3.78	16.05	5.88	24.98	5.88	24.98	5.88	24.98	5.0	3.35	14.26
107	25%	Average	2.1	8.93	0.3	3.4	3.71	15.79	3.71	15.79	3.71	15.79	5.81	24.72	5.81	24.72	5.81	24.72	5.0	2.18	9.27
108	100%	Low	2.1	8.93	0.4	3.4	3.75	15.95	3.75	15.95	3.75	15.95	5.85	24.88	5.85	24.88	5.85	24.88	5.0	5.99	25.47
109	75%	Low	2.1	8.93	0.3	3.4	3.67	15.62	3.67	15.62	3.67	15.62	5.77	24.55	5.77	24.55	5.77	24.55	5.0	4.72	20.08
110	50%	Low	2.1	8.93	0.4	3.4	3.76	15.97	3.76	15.97	3.76	15.97	5.86	24.89	5.86	24.89	5.86	24.89	5.0	3.57	15.18
111	25%	Low	2.1	8.93	0.3	3.4	3.73	15.85	3.73	15.85	3.73	15.85	5.83	24.78	5.83	24.78	5.83	24.78	5.0	2.30	9.79
Maximum Hourly Emissions, Normal Operations (lb/hr)			**2.1**				**3.8**		**3.8**		**3.8**		**5.9**		**5.9**		**5.9**			**6.0**	
Maximum Annual Emissions, Normal Operations at 8503 hours per year (tpy)				**8.9**				**16.1**		**16.1**		**16.1**		**25.1**		**25.1**		**25.1**			**23.7**
Maximum Annual Emissions, Normal Operations at 8760 hours per year (tpy)				9.2				16.6		16.6		16.6		25.8		25.8		25.8			24.4
Maximum Annual Emissions, Normal Operations and Startup/Shutdown combined (tpy)				9.2				16.6		16.6		16.6		25.8		25.8		25.8			24.4

Notes can be found on the last page of Table 2-P

Table 2-P
Turbine Emissions Calculations

Case[1]	Load	Ambient Temperature Scenario	Emission Factor (lb/MMBtu)[25]	1,3-Butadiene (lb/hr)	1,3-Butadiene (tpy)	Acetaldehyde (lb/hr)	Acetaldehyde (tpy)	Acrolein (lb/hr)	Acrolein (tpy)	Benzene (lb/hr)	Benzene (tpy)	Ethylbenzene (lb/hr)	Ethylbenzene (tpy)	Formaldehyde (lb/hr)	Formaldehyde (tpy)	Naphthalene (lb/hr)	Naphthalene (tpy)	PAH[26] (lb/hr)	PAH[26] (tpy)	Propylene Oxide (lb/hr)	Propylene Oxide (tpy)	Toluene (lb/hr)	Toluene (tpy)	Xylenes (lb/hr)	Xylenes (tpy)	Total Organic HAPs[28] (lb/hr)	Total Organic HAPs[28] (tpy)
				4.30E-07	lb/MMBtu	4.00E-05	lb/MMBtu	6.40E-06	lb/MMBtu	9.10E-07	lb/MMBtu	3.20E-05	lb/MMBtu	2.00E-05	lb/MMBtu	1.30E-06	lb/MMBtu	2.20E-06	lb/MMBtu	2.90E-05	lb/MMBtu	1.30E-04	lb/MMBtu	6.40E-05	lb/MMBtu		
100	100%	High		3.36E-04	0.0014	3.13E-02	0.1331	5.01E-03	0.0213	7.12E-04	0.0030	2.50E-02	0.1065	1.57E-02	0.0665	1.02E-03	0.0043	1.72E-03	0.0073	2.27E-02	0.096	1.02E-01	0.43	5.01E-02	0.21	0.3	1.1
101	75%	High		2.69E-04	0.0011	2.50E-02	0.1062	4.00E-03	0.0170	5.68E-04	0.0024	2.00E-02	0.0850	1.25E-02	0.0531	8.12E-04	0.0035	1.37E-03	0.0058	1.81E-02	0.077	8.12E-02	0.35	4.00E-02	0.17	0.2	0.9
102	50%	High		2.04E-04	0.0009	1.90E-02	0.0806	3.03E-03	0.0129	4.31E-04	0.0018	1.52E-02	0.0645	9.48E-03	0.0403	6.16E-04	0.0026	1.04E-03	0.0044	1.37E-02	0.058	6.16E-02	0.26	3.03E-02	0.13	0.2	0.7
103	25%	High		1.33E-04	0.0006	1.24E-02	0.0526	1.98E-03	0.0084	2.82E-04	0.0012	9.90E-03	0.0421	6.19E-03	0.0263	4.02E-04	0.0017	6.81E-04	0.0029	8.98E-03	0.038	4.02E-02	0.17	1.98E-02	0.08	0.1	0.4
104	100%	Average		3.55E-04	0.0015	3.30E-02	0.1405	5.29E-03	0.0225	7.52E-04	0.0032	2.64E-02	0.1124	1.65E-02	0.0702	1.07E-03	0.0046	1.82E-03	0.0077	2.40E-02	0.102	1.07E-01	0.46	5.29E-02	0.22	0.3	1.1
105	75%	Average		2.82E-04	0.0012	2.63E-02	0.1117	4.20E-03	0.0179	5.98E-04	0.0025	2.10E-02	0.0893	1.31E-02	0.0558	8.54E-04	0.0036	1.44E-03	0.0061	1.90E-02	0.081	8.54E-02	0.36	4.20E-02	0.18	0.2	0.9
106	50%	Average		2.14E-04	0.0009	1.99E-02	0.0847	3.19E-03	0.0135	4.53E-04	0.0019	1.59E-02	0.0677	9.96E-03	0.0423	6.47E-04	0.0028	1.10E-03	0.0047	1.44E-02	0.061	6.47E-02	0.28	3.19E-02	0.14	0.2	0.7
107	25%	Average		1.39E-04	0.0006	1.30E-02	0.0551	2.08E-03	0.0088	2.95E-04	0.0013	1.04E-02	0.0441	6.49E-03	0.0276	4.22E-04	0.0018	7.13E-04	0.0030	9.40E-03	0.040	4.22E-02	0.18	2.08E-02	0.09	0.1	0.4
108	100%	Low		3.82E-04	0.0016	3.55E-02	0.1510	5.68E-03	0.0242	8.08E-04	0.0034	2.84E-02	0.1208	1.78E-02	0.0755	1.15E-03	0.0049	1.95E-03	0.0083	2.58E-02	0.109	1.15E-01	0.49	5.68E-02	0.24	0.3	1.2
109	75%	Low		3.01E-04	0.0013	2.80E-02	0.1191	4.48E-03	0.0191	6.38E-04	0.0027	2.24E-02	0.0953	1.40E-02	0.0596	9.11E-04	0.0039	1.54E-03	0.0066	2.03E-02	0.086	9.11E-02	0.39	4.48E-02	0.19	0.2	1.0
110	50%	Low		2.28E-04	0.0010	2.12E-02	0.0901	3.39E-03	0.0144	4.82E-04	0.0020	1.70E-02	0.0721	1.06E-02	0.0451	6.89E-04	0.0029	1.17E-03	0.0050	1.54E-02	0.065	6.89E-02	0.29	3.39E-02	0.14	0.2	0.7
111	25%	Low		1.47E-04	0.0006	1.37E-02	0.0582	2.19E-03	0.0093	3.12E-04	0.0013	1.10E-02	0.0466	6.85E-03	0.0291	4.45E-04	0.0019	7.53E-04	0.0032	9.93E-03	0.042	4.45E-02	0.19	2.19E-02	0.09	0.1	0.5
Maximum Hourly Emissions, Normal Operations (lb/hr)				**0.000**		**0.036**		**0.006**		**0.001**		**0.028**		**0.018**		**0.001**		**0.002**		**0.026**		**0.115**		**0.057**		**0.290**	
Maximum Annual Emissions, Normal Operations at 8503 hours per year (tpy)					**0.002**		**0.140**		**0.022**		**0.003**		**0.112**		**0.070**		**0.005**		**0.008**		**0.102**		**0.457**		**0.225**		**1.15**
Maximum Annual Emissions, Normal Operations at 8760 hours per year (tpy)					0.002		0.145		0.023		0.003		0.116		0.072		0.005		0.008		0.105		0.470		0.232		1.18
Maximum Annual Emissions, Normal Operations and Startup/Shutdown combined (tpy)					0.002		0.145		0.023		0.003		0.116		0.072		0.005		0.008		0.105		0.470		0.232		**1.18**

Notes can be found on the last page of Table 2-P

Notes

[1] Data from turbine and catalyst vendor performance spreadsheets, which are attached
[2] The temperatures shown are the ambient temperatures used by the equipment vendors in predicting equipment performance
[3] °F = degrees Fahrenheit
[4] % = percent
[5] MMBtu/hr = million British thermal units per hour
[6] acfs = actual cubic feet per second
[7] Stack diameter and stack height based on a previous project.
[8] ft/sec = feet per second
[9] dscfs = dry standard cubic feet per second
[10] °K = degrees Kelvin
[11] m = meters
[12] m/sec = meters per second
[13] NO_X = nitrogen oxides
[14] The NO_X, CO, Total PM, NH_3 and VOC emisison rates are based on the turbine and catalyst vendor performance spreadsheets, which are attached
[15] ppm = parts per million by volume
[16] lb/hr = pounds per hour
[17] tpy = tons per year
[18] CO = carbon monoxide
[19] VOC = volatile organic compounds
[20] SO_2 = sulphur dioxide
[21] PM = particulate matter
[22] PM_{10} = particulate matter less than or equal to 10 microns in aerodynamic diameter
[23] $PM_{2.5}$ = particulate matter less than or equal to 2.5 microns in aerodynamic diameter
[24] NH3 = ammonia
[25] lb/MMBtu = pounds per million British thermal units.
[26] PAH = Polycyclic aromatic hydrocarbons
[27] HAPs = hazardous air pollutants

Final Exhaust from SCR and Oxidation Catalyst

GIVEN / CALCULATED DATA CASE		**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**	**116**	**117**	**118**	**119**
Case Description	Conditioning	**EVAP**	**EVAP**	**EVAP**	**EVAP**	**EVAP**	**EVAP**	**EVAP**	**EVAP**	**NONE**	**NONE**	**NONE**	**NONE**	**CHILL**	**CHILL**	**CHILL**	**CHILL**	**CHILL**	**CHILL**	**CHILL**	**CHILL**
TURBINE LOAD	%	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25	100	75	50	25
Site Elevation		3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917	3,917
AMBIENT	°F	105	105	105	105	64	64	64	64	15	15	15	15	105	105	105	105	64	64	64	64
TURBINE EXHAUST FLOW	lb/hr	1,471,270	1,260,113	1,013,277	730,364	1,552,170	1,333,066	1,060,543	759,375	1,664,252	1,438,787	1,127,032	798,053	1,567,005	1,347,222	1,068,923	764,002	1,569,024	1,349,108	1,069,903	764,526
GAS TEMP. FROM TURBINE	°F	794.0	795.9	836.5	888.9	777.1	773.1	823.7	882.8	755.4	742.8	804.9	869.9	774.1	768.5	822.0	882.4	773.7	768.0	822.1	882.8
TURBINE EXHAUST GAS ANAL., % VOL.	Ar	0.86	0.87	0.87	0.88	0.86	0.87	0.87	0.88	0.87	0.88	0.88	0.89	0.87	0.87	0.88	0.88	0.87	0.87	0.88	0.89
	N2	72.24	72.67	72.91	73.50	72.40	72.95	73.33	73.96	72.86	73.55	73.87	74.52	72.57	73.16	73.54	74.16	72.65	73.25	73.63	74.26
	O2	11.54	12.17	12.65	13.43	11.57	12.29	12.72	13.49	11.66	12.51	12.83	13.60	11.61	12.35	12.76	13.53	11.62	12.37	12.78	13.55
	CO2	4.07	3.81	3.60	3.27	4.08	3.79	3.62	3.30	4.10	3.76	3.63	3.33	4.08	3.78	3.62	3.31	4.09	3.79	3.63	3.32
	H2O	11.28	10.48	9.97	8.91	11.08	10.10	9.46	8.36	10.51	9.31	8.78	7.66	10.87	9.83	9.20	8.11	10.77	9.72	9.08	7.99
HUMIDITY	%	8.6	8.6	8.6	8.6	25.0	25.0	25.0	25.0	20.0	20.0	20.0	20.0	8.6	8.6	8.6	8.6	25.0	25.0	25.0	25.0
GIVEN: TURBINE CO	ppmvd @ 15% O2	51	54	75	148	55	51	63	110	65	53	62	100	61	52	60	101	65	53	60	97
CALC.: TURBINE CO, lb/hr	lb/hr	89.4	74.4	78.9	101.8	100.6	74.4	69.1	79.5	128.5	83.1	72.5	76.3	113.0	76.3	67.1	73.2	120.2	77.8	66.5	70.6
GIVEN: TURBINE NOx	ppmvd @ 15% O2	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
CALC.: TURBINE NOx, lb/hr	lb/hr	71.4	57.0	43.2	28.2	75.4	59.9	45.4	29.5	81.1	63.9	48.3	31.2	76.2	60.4	45.8	29.8	76.3	60.5	45.9	29.8
CALC. GAS MOL. WT.		28.10	28.17	28.20	28.29	28.13	28.21	28.26	28.35	28.19	28.29	28.34	28.43	28.15	28.24	28.29	28.38	28.16	28.25	28.30	28.39
SOx from Turbine	lb/hr																				
SO2 from Turbine	lb/hr	0.51	0.40	0.31	0.20	0.53	0.42	0.32	0.21	0.57	0.45	0.34	0.22	0.54	0.43	0.32	0.21	0.54	0.43	0.32	0.21
SO3 from Turbine	lb/hr	0.03	0.03	0.02	0.01	0.04	0.03	0.02	0.01	0.04	0.03	0.02	0.01	0.04	0.03	0.02	0.01	0.04	0.03	0.02	0.01
Particulate	lb/hr	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
VOC -NMNEHC	ppmvd @ 15% O2	2.00	2.00	2.00	4.37	2.00	2.00	2.00	2.88	2.00	2.00	2.00	2.58	2.00	2.00	2.00	2.59	2.00	2.00	2.00	2.48
AMBIENT AIR FLOW(Tempering)	lb/hr	**10,000**	**10,000**	**10,000**	**41,000**	**10,000**	**10,000**	**10,000**	**34,000**	**10,000**	**10,000**	**10,000**	**20,000**	**10,000**	**10,000**	**10,000**	**35,000**	**10,000**	**10,000**	**10,000**	**34,000**
	ACFM	**2,742**	**2,742**	**2,742**	**11,240**	**2,547**	**2,547**	**2,547**	**8,660**	**2,303**	**2,303**	**2,303**	**4,606**	**2,742**	**2,742**	**2,742**	**9,595**	**2,547**	**2,547**	**2,547**	**8,660**
	SCFM	**2,230**	**2,230**	**2,230**	**9,144**	**2,234**	**2,234**	**2,234**	**7,597**	**2,229**	**2,229**	**2,229**	**4,457**	**2,230**	**2,230**	**2,230**	**7,806**	**2,234**	**2,234**	**2,234**	**7,597**
AIR + GAS MIXTURE TEMP.	°F	**790**	**791**	**830**	**850**	**773**	**768**	**817**	**850**	**751**	**738**	**798**	**850**	**770**	**764**	**816**	**850**	**769**	**763**	**815**	**850**
TOTAL AIR + GAS FLOW	lb/hr	1,481,270	1,270,113	1,023,277	771,364	1,562,170	1,343,066	1,070,543	793,375	1,674,252	1,448,787	1,137,032	818,053	1,577,005	1,357,222	1,078,923	799,002	1,579,024	1,359,108	1,079,903	798,526
AIR + GAS COMPOSITION, % VOL.	N2	72.28	72.70	72.96	73.69	72.43	72.98	73.37	74.09	72.89	73.58	73.91	74.59	72.60	73.19	73.57	74.29	72.68	73.28	73.66	74.37
	O2	11.60	12.24	12.72	13.81	11.63	12.35	12.79	13.80	11.71	12.56	12.90	13.77	11.66	12.41	12.83	13.84	11.68	12.43	12.85	13.85
	CO2	4.05	3.78	3.56	3.10	4.05	3.76	3.58	3.16	4.07	3.73	3.60	3.25	4.06	3.76	3.59	3.17	4.06	3.76	3.59	3.18
	H2O	11.22	10.42	9.90	8.55	11.03	10.04	9.39	8.09	10.46	9.26	8.72	7.53	10.82	9.78	9.13	7.84	10.72	9.66	9.02	7.74
	AR	0.86	0.86	0.86	0.84	0.86	0.87	0.87	0.86	0.86	0.87	0.87	0.87	0.86	0.87	0.87	0.85	0.86	0.87	0.87	0.86
AIR + GAS MOL WT		28.11	28.17	28.21	28.31	28.13	28.21	28.27	28.37	28.19	28.29	28.34	28.44	28.15	28.24	28.30	28.40	28.16	28.25	28.31	28.41
CO AT CATALYST FACE -	ppmvd @ 15% O2	51	54	75	149	55	51	63	111	65	53	62	101	61	52	60	101	65	53	60	97
NOx AT CATALYST FACE -	ppmvd @ 15% O2	25.0	25.0	25.0	25.1	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
DESIGN REQUIREMENTS																					
CO CATALYST CO OUT	ppmvd @ 15% O2	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
REQUIRED NOx OUT	ppmvd @ 15% O2	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
NH3 SLIP	ppmvd @ 15% O2	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
VOC	ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
PM10	lb/hr	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
GUARANTEED PERFORMANCE DATA																					
CO OUT, ppmvd @ 15% O2 - Max.	ppmvd @ 15% O2	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
NOx OUT, ppmvd @ 15% O2 - Max.	ppmvd @ 15% O2	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
NH3 SLIP, ppmvd @ 15% O2 - Max.	ppmvd @ 15% O2	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
VOC	ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total PM10*	lb/hr	5.9	5.9	5.9	5.8	5.9	5.8	5.9	5.8	5.9	5.8	5.9	5.8	5.9	5.9	5.8	5.9	5.8	5.9	5.8	5.8
VOC Conversion	%	0.0%	0.0%	0.0%	54.2%	0.0%	0.0%	0.0%	30.7%	0.0%	0.0%	0.0%	22.4%	0.0%	0.0%	0.0%	22.7%	0.0%	0.0%	0.0%	19.4%
CO CATALYST CO CONVERSION, Min.	%	77.6%	78.5%	84.7%	92.3%	79.0%	77.5%	81.6%	89.6%	82.3%	78.5%	81.4%	88.6%	81.1%	77.8%	80.9%	88.6%	82.2%	78.2%	80.7%	88.2%
CO OUT, lb/hr - Max.	lb/hr	**20.0**	**16.0**	**12.1**	**7.9**	**21.1**	**16.8**	**12.7**	**8.3**	**22.7**	**17.9**	**13.5**	**8.7**	**21.3**	**16.9**	**12.8**	**8.3**	**21.4**	**16.9**	**12.8**	**8.3**
SCR CATALYST NOx CONVERSION, Min.	%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%	88.8%
NOx OUT, lb/hr - Max.	lb/hr	**8.0**	**6.4**	**4.8**	**3.2**	**8.4**	**6.7**	**5.1**	**3.3**	**9.1**	**7.2**	**5.4**	**3.5**	**8.5**	**6.8**	**5.1**	**3.3**	**8.5**	**6.8**	**5.1**	**3.3**
DESIGN INLET ALPHA - NH3:NOx		1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
EXPECTED AQ. NH3 (19% SOL.) FLOW	lb/hr	184.9	150.9	130.3	102.2	189.5	151.7	131.2	105.7	197.2	153.9	132.4	110.0	190.6	151.8	131.7	106.3	190.7	151.8	131.8	106.5
NH3 SLIP, ppmv	ppmv	5.9	5.5	5.2	4.5	5.9	5.5	5.2	4.6	5.9	5.4	5.2	4.7	5.9	5.5	5.2	4.6	5.9	5.5	5.2	4.6
NH3 SLIP, lb/hr	lb/hr	5.3	4.2	3.2	2.1	5.6	4.4	3.4	2.2	6.0	4.7	3.6	2.3	5.6	4.5	3.4	2.2	5.6	4.5	3.4	2.2
CO Catalyst Conversion of SO2 to SO3	%	34%	38%	53%	66%	29%	31%	49%	65%	22%	22%	43%	65%	28%	30%	49%	65%	28%	29%	49%	65%
SCR Catalyst Conversion of SO2 to SO3	%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
Total Conversion	%	36%	40%	55%	68%	31%	33%	51%	67%	24%	24%	45%	67%	30%	32%	51%	67%	30%	31%	51%	67%
SO2 from Turbine	Moles	0.01	0.01	0.00	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.00
SO3 from Turbine	Moles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Converted to SO3 by CO Catalyst	Moles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total SO3	Moles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total PM10 taken as Ammonia Sulfate	lb/hr	0.4	0.4	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3	0.4	0.3
PM10 From Turbine	lb/hr	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.5
VOC as CH4	lb/hr	1.99	1.59	1.20	0.78	2.10	1.67	1.26	0.82	2.26	1.78	1.34	0.87	2.12	1.68	1.27	0.83	2.12	1.68	1.28	0.83
EMISSIONS PER YEAR																					
Operating Hours	hr/yr	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
CO OUT	tons/yr	87.6	69.9	53.0	34.5	92.5	73.4	55.7	36.2	99.4	78.4	59.2	38.2	93.4	74.1	56.1	36.5	93.6	74.2	56.2	36.5
NOx OUT	tons/yr	35.0	27.9	21.2	13.8	37.0	29.4	22.3	14.5	39.8	31.3	23.7	15.3	37.4	29.6	22.5	14.6	37.4	29.7	22.5	14.6
NH3 SLIP	tons/yr	23.1	18.4	14.0	9.1	24.4	19.4	14.7	9.6	26.2	20.7	15.6	10.1	24.7	19.6	14.8	9.6	24.7	19.6	14.8	9.6
Total PM10 taken as Ammonia Sulfate*	tons/yr	1.9	1.7	1.7	1.3	1.7	1.5	1.6	1.4	1.5	1.2	1.6	1.4	1.7	1.4	1.6	1.4	1.7	1.4	1.6	1.4
PM10 From Turbine	tons/yr	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1	24.1
Total PM10	tons/yr	26.0	25.7	25.8	25.4	25.8	25.6	25.7	25.5	25.6	25.3	25.6	25.5	25.8	25.5	25.7	25.5	25.8	25.5	25.7	25.5
VOC as CH4	tons/yr	8.70	6.94	5.26	3.43	9.19	7.30	5.53	3.60	9.88	7.79	5.89	3.80	9.28	7.36	5.58	3.62	9.30	7.37	5.59	3.63

*Based on 0.25 gr/100 SCF Sulfur in N.G. fuel.

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Energy

Performance By: **Adesoji Dairo**
Project Info:

Engine: **LMS100 PA**
Deck Info: **G0179D - 8ih.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.85PF (35404)**
Fuel: **Gas Fuel #10-1, 19000 Btu/lb,LHV**

Date: **05/14/2010**
Time: **3:53:52 PM**
Version: **3.8.6**

Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**	**116**	**117**	**118**	**119**
Ambient Conditions																				
Dry Bulb, °F	105.0	105.0	105.0	105.0	64.0	64.0	64.0	64.0	15.0	15.0	15.0	15.0	105.0	105.0	105.0	105.0	64.0	64.0	64.0	64.0
Wet Bulb, °F	63.1	63.1	63.1	63.1	46.2	46.2	46.2	46.2	9.9	9.9	9.9	9.9	63.0	63.0	63.0	63.0	46.2	46.2	46.2	46.2
RH, %	8.6	8.6	8.6	8.6	25.0	25.0	25.0	25.0	20.0	20.0	20.0	20.0	8.6	8.6	8.6	8.6	25.0	25.0	25.0	25.0
Altitude, ft	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0	3917.0
Ambient Pressure, psia	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732	12.732
Engine Inlet																				
Comp Inlet Temp, °F	69.3	69.3	69.3	69.3	48.9	48.9	48.9	48.9	15.0	15.0	15.0	15.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
RH, %	72.3	72.3	72.3	72.3	83.4	83.4	83.4	83.4	20.0	20.0	20.0	20.0	64.3	64.3	64.3	64.3	50.0	50.0	50.0	50.0
Conditioning	EVAP	EVAP	EVAP	EVAP	EVAP	EVAP	EVAP	EVAP	NONE	NONE	NONE	NONE	CHILL	CHILL	CHILL	CHILL	CHILL	CHILL	CHILL	CHILL
Tons or kBtu/hr	0	0	0	0	0	0	0	0	0	0	0	0	1875	1672	1533	1270	593	529	485	402
Pressure Losses																				
Inlet Loss, inH20	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Exhaust Loss, inH20	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00
Partload %	**100**	**75**	**50**	**25**	**100**	**75**	**50**	**25**	**100**	**75**	**50**	**25**	**100**	**75**	**50**	**25**	**100**	**75**	**50**	**25**
kW, Gen Terms	**88378**	**66297**	**44212**	**22143**	**95304**	**71493**	**47676**	**23871**	**104820**	**78623**	**52431**	**26246**	**96490**	**72382**	**48265**	**24168**	**96613**	**72475**	**48326**	**24201**
Est. Btu/kW-hr, LHV	**7990**	**8502**	**9670**	**12613**	**7823**	**8287**	**9422**	**12256**	**7646**	**8041**	**9119**	**11768**	**7806**	**8257**	**9389**	**12205**	**7807**	**8257**	**9390**	**12206**
Guar. Btu/kW-hr, LHV	**8195**	**--**	**--**	**--**	**8023**	**--**	**--**	**--**	**7842**	**--**	**--**	**--**	**8006**	**--**	**--**	**--**	**8008**	**--**	**--**	**--**
Fuel Flow																				
MMBtu/hr, LHV	706.1	563.7	427.5	279.3	745.5	592.5	449.2	292.6	801.4	632.2	478.1	308.9	753.2	597.7	453.2	295.0	754.3	598.5	453.8	295.4
lb/hr	37165	29667	22501	14699	39238	31182	23642	15398	42180	33276	25164	16257	39641	31457	23852	15525	39700	31498	23884	15547
NOx Control	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**	**Water**
Water Injection																				
lb/hr	22325	15364	9621	4397	24849	17487	11610	5756	30524	21100	14348	7373	26331	18430	12258	6207	26862	18779	12496	6378
Temperature, °F	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Intercooler	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**	**Wet Cooling**
Humidification	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
IC Heat Extraction, btu/s	26854	20199	13198	7341	24773	18903	12090	6458	22991	17235	9962	4696	24613	18795	11859	6255	24644	18820	11857	6249
KOD Water Extraction, lb/s	1.4	0.8	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Control Parameters																				
HP Speed, RPM	9162	9005	8870	8667	9160	8989	8876	8675	9151	8956	8880	8685	9156	8981	8875	8677	9155	8979	8875	8676
LP Speed, RPM	5311	5041	4917	4774	5306	4991	4846	4695	5352	4918	4717	4555	5308	4982	4832	4679	5309	4983	4832	4679
PT Speed, RPM	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600	3600
PS3 - CDP, psia	465.7	412.0	321.2	219.0	496.5	440.2	337.2	232.1	476.8	440.2	345.6	257.1	465.7	436.6	339.0	227.3	496.5	443.6	339.9	233.5

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Energy

Performance By: **Adesoji Dairo**
Project Info:

Engine: **LMS100 PA**
Deck Info: **G0179D - 8ih.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.85PF (35404)**
Fuel: **Gas Fuel #10-1, 19000 Btu/lb,LHV**

Date: **05/14/2010**
Time: **3:53:52 PM**
Version: **3.8.6**

Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**	**116**	**117**	**118**	**119**
T23 - Intcrl Inlet Temp, °F	353.0	322.9	285.4	241.6	335.3	307.0	264.0	219.2	304.3	274.8	226.1	180.1	332.1	304.1	259.8	214.7	332.4	304.3	259.8	214.7
P23 - Intcrl Inlet Pressure, psia	49.7	44.4	37.7	29.8	52.0	46.8	39.1	30.5	55.1	50.4	41.1	31.7	52.3	47.2	39.3	30.6	52.4	47.2	39.3	30.6
W23 - Intcrl Inlet Flow, lb/s	395.8	357.9	321.2	265.3	415.7	371.4	339.2	280.8	444.8	396.0	367.5	304.8	419.3	374.0	342.9	284.1	419.7	374.4	343.5	284.7
T25 - HPC Inlet Temp, °F	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
T3CRF - CDT, °F	696	670	646	608	698	669	650	614	701	668	655	619	699	670	652	616	699	670	652	616
T48IN, °R	2044	1964	1902	1802	2044	1955	1906	1810	2044	1941	1908	1816	2044	1953	1907	1813	2044	1953	1908	1813
T48IN, °F	1584	1504	1442	1343	1584	1496	1446	1350	1584	1481	1448	1356	1584	1493	1448	1353	1584	1493	1448	1354
Exhaust Parameters																				
Temperature, °F	794.0	795.9	836.5	888.9	777.1	773.1	823.7	882.8	755.4	742.8	804.9	869.9	774.1	768.5	822.0	882.4	773.7	768.0	822.1	882.8
lb/sec	408.7	350.0	281.5	202.9	431.2	370.3	294.6	210.9	462.3	399.7	313.1	221.7	435.3	374.2	296.9	212.2	435.8	374.8	297.2	212.4
lb/hr	1471270	1260113	1013277	730364	1552170	1333066	1060543	759375	1664252	1438787	1127032	798053	1567005	1347222	1068923	764002	1569024	1349108	1069903	764526
Energy, Btu/s- Ref 0 °R	132327	113047	93789	70137	137448	117031	96852	72344	144175	122482	100942	74962	138245	117635	97341	72664	138300	117676	97378	72691
Cp, Btu/lb-R	0.2755	0.2742	0.2748	0.2749	0.2745	0.2727	0.2735	0.2738	0.2728	0.2704	0.2717	0.2722	0.2741	0.2721	0.2730	0.2734	0.2739	0.2719	0.2729	0.2732
Emissions (ESTIMATED, NOT FOR GUARANTEE)																				
NOx ppmvd Ref 15% O2	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
NOx as NO2, lb/hr	71	57	43	28	75	60	45	30	81	64	48	31	76	60	46	30	76	61	46	30
CO ppmvd Ref 15% O2	13	14	18	25	12	14	18	26	14	14	17	26	13	15	17	26	13	15	17	26
CO, lb/hr	22.05	19.70	19.10	17.22	22.60	20.84	19.63	18.70	26.91	22.02	20.45	19.57	24.27	21.31	19.39	18.96	24.86	21.43	19.24	19.01
CO2, lb/hr	93824.04	74932.98	56854.41	37165.82	99059.80	78766.14	59736.89	38931.22	106484.90	84065.00	63584.82	41101.66	100074.60	79461.78	60268.12	39250.69	100223.60	79565.16	60349.70	39305.67
HC ppmvd Ref 15% O2	2	3	3	3	2	2	3	4	3	2	3	3	2	3	3	4	3	3	3	4
HC, lb/hr	2.36	1.92	1.64	1.29	2.46	2.01	1.69	1.41	2.78	2.11	1.77	1.48	2.55	2.04	1.68	1.43	2.59	2.04	1.67	1.44
SOX as SO2, lb/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Max Estimated Emissions (NOT FOR GUARANTEE)																				
NOx ppmvd Ref 15% O2	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**	**25**
NOx as NO2, lb/hr	**71**	**57**	**43**	**28**	**75**	**60**	**45**	**29**	**81**	**64**	**48**	**31**	**76**	**60**	**46**	**30**	**76**	**60**	**46**	**30**
CO ppmvd Ref 15% O2	**51**	**54**	**75**	**148**	**55**	**51**	**63**	**110**	**65**	**53**	**62**	**100**	**61**	**52**	**60**	**101**	**65**	**53**	**60**	**97**
CO, lb/hr	**97.7**	**81.2**	**86.2**	**111.1**	**109.9**	**81.3**	**75.4**	**86.7**	**140.4**	**90.9**	**79.2**	**83.2**	**123.5**	**83.4**	**73.2**	**79.8**	**131.3**	**85.1**	**72.6**	**77.0**
HC ppmvd Ref 15% O2	**10**	**10**	**10**	**22**	**10**	**10**	**10**	**14**	**10**	**10**	**10**	**13**	**10**	**10**	**10**	**13**	**10**	**10**	**10**	**12**
HC, lb/hr	**10.8**	**8.6**	**6.5**	**9.3**	**11.4**	**9.0**	**6.8**	**6.4**	**12.2**	**9.7**	**7.3**	**6.1**	**11.5**	**9.1**	**6.9**	**5.8**	**11.5**	**9.1**	**6.9**	**5.6**
VOC ppmvd Ref 15% O2	**2.0**	**2.0**	**2.0**	**4.4**	**2.0**	**2.0**	**2.0**	**2.9**	**2.0**	**2.0**	**2.0**	**2.6**	**2.0**	**2.0**	**2.0**	**2.6**	**2.0**	**2.0**	**2.0**	**2.5**
VOC, lb/hr	**1.99**	**1.58**	**1.20**	**1.71**	**2.10**	**1.67**	**1.26**	**1.19**	**2.26**	**1.78**	**1.35**	**1.12**	**2.12**	**1.68**	**1.27**	**1.07**	**2.12**	**1.69**	**1.28**	**1.03**
PM10, lb/hr (Total)	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**	**5.5**
Exh Wght % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)																				
AR	1.2245	1.2292	1.2320	1.2385	1.2262	1.2323	1.2365	1.2434	1.2312	1.2388	1.2423	1.2493	1.2281	1.2346	1.2387	1.2456	1.2289	1.2355	1.2397	1.2466
N2	72.0209	72.2826	72.4323	72.7960	72.1200	72.4620	72.6976	73.0836	72.4140	72.8395	73.0389	73.4332	72.2285	72.5927	72.8279	73.2115	72.2789	72.6498	72.8864	73.2698
O2	13.1436	13.8307	14.3491	15.1962	13.1672	13.9392	14.4001	15.2307	13.2342	14.1481	14.4922	15.3050	13.1943	13.9941	14.4324	15.2548	13.2079	14.0125	14.4469	15.2675
CO2	6.3771	5.9465	5.6109	5.0887	6.3820	5.9086	5.6327	5.1267	6.3984	5.8428	5.6418	5.1502	6.3864	5.8982	5.6382	5.1375	6.3876	5.8976	5.6407	5.1412
H20	7.2289	6.7060	6.3706	5.6755	7.0996	6.4531	6.0282	5.3103	6.7170	5.9261	5.5798	4.8569	6.9577	6.2756	5.8579	5.1452	6.8915	6.1998	5.7813	5.0696
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0015	0.0016	0.0019	0.0024	0.0015	0.0016	0.0019	0.0025	0.0016	0.0015	0.0018	0.0025	0.0015	0.0016	0.0018	0.0025	0.0016	0.0016	0.0018	0.0025
HC	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
NOX	0.0033	0.0031	0.0029	0.0027	0.0033	0.0031	0.0029	0.0027	0.0033	0.0031	0.0029	0.0027	0.0033	0.0031	0.0029	0.0027	0.0033	0.0031	0.0029	0.0027

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Energy

Performance By: **Adesoji Dairo**
Project Info:

Engine: **LMS100 PA**
Deck Info: **G0179D - 8ih.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.85PF (35404)**
Fuel: **Gas Fuel #10-1, 19000 Btu/lb,LHV**

Date: **05/14/2010**
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Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**	**116**	**117**	**118**	**119**
Exh Mole % Dry (NOT FOR USE IN ENVIRONMENTAL PERMITS)																				
AR	0.9708	0.9681	0.9660	0.9627	0.9708	0.9678	0.9660	0.9628	0.9708	0.9672	0.9659	0.9628	0.9708	0.9676	0.9660	0.9629	0.9708	0.9676	0.9660	0.9629
N2	81.4248	81.1770	80.9886	80.6936	81.4227	81.1485	80.9892	80.7032	81.4174	81.0963	80.9799	80.7026	81.4198	81.1370	80.9867	80.7041	81.4181	81.1342	80.9856	80.7039
O2	13.0096	13.5987	14.0465	14.7475	13.0147	13.6666	14.0451	14.7246	13.0271	13.7907	14.0672	14.7259	13.0214	13.6938	14.0510	14.7223	13.0255	13.7005	14.0537	14.7228
CO2	4.5894	4.2510	3.9936	3.5906	4.5865	4.2120	3.9944	3.6037	4.5793	4.1408	3.9817	3.6029	4.5826	4.1964	3.9911	3.6050	4.5802	4.1926	3.9896	3.6047
H20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0017	0.0018	0.0021	0.0026	0.0016	0.0018	0.0021	0.0027	0.0018	0.0017	0.0020	0.0027	0.0017	0.0018	0.0020	0.0027	0.0018	0.0018	0.0020	0.0027
HC	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0004	0.0003	0.0003	0.0003	0.0004	0.0003	0.0003	0.0003	0.0004	0.0003	0.0003	0.0003	0.0004
NOX	0.0033	0.0031	0.0029	0.0026	0.0033	0.0031	0.0029	0.0026	0.0033	0.0030	0.0029	0.0026	0.0033	0.0031	0.0029	0.0026	0.0033	0.0031	0.0029	0.0026
Exh Mole % Wet (NOT FOR USE IN ENVIRONMENTAL PERMITS)																				
AR	0.8614	0.8666	0.8697	0.8769	0.8632	0.8700	0.8747	0.8824	0.8687	0.8772	0.8811	0.8890	0.8652	0.8725	0.8771	0.8848	0.8662	0.8736	0.8782	0.8859
N2	72.2434	72.6668	72.9122	73.5028	72.3988	72.9505	73.3311	73.9591	72.8607	73.5502	73.8731	74.5175	72.5691	73.1575	73.5375	74.1631	72.6483	73.2478	73.6305	74.2561
O2	11.5427	12.1730	12.6458	13.4333	11.5723	12.2860	12.7170	13.4941	11.6579	12.5074	12.8327	13.5973	11.6059	12.3470	12.7586	13.5291	11.6225	12.3688	12.7773	13.5465
CO2	4.0719	3.8054	3.5953	3.2707	4.0782	3.7865	3.6167	3.3025	4.0980	3.7555	3.6323	3.3268	4.0844	3.7837	3.6240	3.3128	4.0868	3.7850	3.6272	3.3167
H20	11.2759	10.4836	9.9722	8.9113	11.0828	10.1024	9.4557	8.3566	10.5097	9.3051	8.7760	7.6641	10.8705	9.8347	9.1980	8.1050	10.7713	9.7202	9.0820	7.9895
SO2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0015	0.0016	0.0019	0.0024	0.0015	0.0016	0.0019	0.0025	0.0016	0.0015	0.0018	0.0025	0.0016	0.0016	0.0018	0.0025	0.0016	0.0016	0.0018	0.0025
HC	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
NOX	0.0030	0.0028	0.0026	0.0024	0.0030	0.0028	0.0026	0.0024	0.0030	0.0027	0.0026	0.0024	0.0030	0.0028	0.0026	0.0024	0.0030	0.0028	0.0026	0.0024

Aero Energy Fuel Number	**10-1 (GEDEF)**	
	Volume %	**Weight %**
Hydrogen	0.0000	0.0000
Methane	84.5000	71.8447
Ethane	5.5800	8.8924
Ethylene	0.0000	0.0000
Propane	2.0500	4.7909
Propylene	0.0000	0.0000
Butane	0.7800	2.4027
Butylene	0.0000	0.0000
Butadiene	0.0000	0.0000
Pentane	0.1800	0.6883
Cyclopentane	0.0000	0.0000
Hexane	0.1700	0.7764
Heptane	0.0000	0.0000
Carbon Monoxide	0.0000	0.0000
Carbon Dioxide	0.6700	1.5628
Nitrogen	5.9300	8.8044
Water Vapor	0.0000	0.0000
Oxygen	0.1400	0.2374
Hydrogen Sulfide	0.0000	0.0000
Ammonia	0.0000	0.0000

Estimated Average Engine Performance NOT FOR GUARANTEE, REFER TO PROJECT F&ID FOR DESIGN
Predicted Intercooler Performance not to be utilized for Balance of Plant design. Please contact GE.

GE Energy

Performance By: **Adesoji Dairo**
Project Info:

Engine: **LMS100 PA**
Deck Info: **G0179D - 8ih.scp**
Generator: **BDAX 82-445ER 60Hz, 13.8kV, 0.85PF (35404)**
Fuel: **Gas Fuel #10-1, 19000 Btu/lb,LHV**

Date: **05/14/2010**
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Case #	**100**	**101**	**102**	**103**	**104**	**105**	**106**	**107**	**108**	**109**	**110**	**111**	**112**	**113**	**114**	**115**	**116**	**117**	**118**	**119**
Btu/lb, LHV	19000																			
Btu/scf, LHV	946.0																			
Btu/scf, HHV	1047.0																			
Btu/lb, HHV	20996																			
Fuel Temp, °F	77.0																			
NOx Scalar	0.998																			
Specific Gravity	0.65																			
Wobbe	50.657																			
Engine Exhaust																				
Exhaust Avg. Mol. Wt., Wet Basis	28.1	28.2	28.2	28.3	28.1	28.2	28.3	28.3	28.2	28.3	28.3	28.4	28.1	28.2	28.3	28.4	28.2	28.2	28.3	28.4
Exhaust Flow, ACFM	891186	762748	632324	472766	926767	791096	653931	488206	974079	830356	682940	506768	932594	795714	657557	490567	933131	796154	657918	490827
Exhaust Flow, SCFM	315944	270000	216829	155811	333058	285226	226473	161637	356291	306928	240027	169404	335473	287544	227701	162225	335774	287817	227805	162261
Exhaust Flow, Btu/lb	324	323	333	346	319	316	329	343	312	306	322	338	318	314	328	342	317	314	328	342
Exhaust Flow, Calories/s	33346499	28487740	23634848	17674518	34636786	29491826	24406698	18230599	36332210	30865533	25437329	18890418	34837779	29643953	24530038	18311352	34851671	29654291	24539226	18318177
Inlet Flow Wet, pps	396.0	358.1	321.4	265.5	415.9	371.6	339.4	280.9	445.1	396.2	367.7	304.9	419.5	374.1	343.1	284.2	419.9	374.5	343.7	284.8
Inlet Flow Dry, pps	390.9	353.5	317.3	262.1	413.0	369.0	337.0	279.0	444.9	396.0	367.5	304.8	417.6	372.4	341.5	282.9	418.4	373.2	342.4	283.8
Shaft HP	120346	90554	60797	31113	129711	97561	65460	33436	142576	107182	71864	36629	131313	98755	66255	33834	131480	98881	66339	33877
Generator Information																				
Capacity kW	132652	132652	132652	132652	157559	160488	160488	160488	167999	182059	182059	182059	182059	132652	132652	132652	169788	160488	160488	160488
Efficiency	0.9848	0.9818	0.9752	0.9544	0.9825	0.9827	0.9767	0.9574	0.9836	0.9837	0.9784	0.9609	0.9827	0.9829	0.9769	0.9579	0.9827	0.9829	0.9769	0.9580
Inlet Temp, °F	105.0	105.0	105.0	105.0	64.0	64.0	64.0	64.0	15.0	15.0	15.0	15.0	105.0	105.0	105.0	105.0	64.0	64.0	64.0	64.0
Gear Box Loss	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8th Stage Bleed																				
Flow, pps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pressure, psia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Temperature, °R	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CDP Bleed																				
Flow, pps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pressure, psia	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Est. Gas Pressure at Baseplate, psig	**729.4**	**602.8**	**473.4**	**330.5**	**768.6**	**634.0**	**495.3**	**343.7**	**823.3**	**677.9**	**525.2**	**360.7**	**775.9**	**639.7**	**499.2**	**345.9**	**776.9**	**640.5**	**499.7**	**346.2**
WAR36 - Combustor Water to Air Ratio	0.0317	0.0283	0.0262	0.0215	0.0307	0.0263	0.0230	0.0180	0.0274	0.0218	0.0189	0.0137	0.0294	0.0247	0.0214	0.0164	0.0288	0.0240	0.0206	0.0156
WA36 - Combustor Air Flow	276.47	238.17	192.29	139.97	292.05	252.61	201.93	146.01	314.35	274.10	215.52	154.08	295.26	255.75	203.86	147.13	295.84	256.30	204.21	147.34
WF36 - Combustor Fuel Flow	37164.75	29666.84	22501.30	14699.27	39237.95	31182.30	23641.83	15398.47	42180.39	33275.57	25163.76	16256.79	39640.67	31457.02	23851.63	15524.96	39699.91	31497.79	23883.72	15546.71
CardPack	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**	**8ih**
Intercooler CardPack																				
NSI	**304**	**0**	**0**	**0**	**304**	**0**	**0**	**0**	**304**	**0**	**0**	**0**	**304**	**0**	**0**	**0**	**304**	**0**	**0**	**0**
NSI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1733**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
NSI	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

[a]Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

[b]These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and off shore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.

[c]The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Uncontrolled SOCMI Fugitive Emission Factors

Equipment/Service	SOCMI Average[1]	SOCMI Without C_2[2]	SOCMI With C_2[2]	SOCMI Non-Leaker[3]
Valves				
Gas/Vapor	0.0132	0.0089	0.0258	0.00029
Light Liquid	0.0089	0.0035	0.0459	0.00036
Heavy Liquid	0.0005	0.0007	0.0005	0.0005
Pumps				
Light Liquid	0.0439	0.0386	0.144	0.0041
Heavy Liquid	0.019	0.0161	0.0046	0.0046
Flanges/Connectors				
Gas/Vapor	0.0039	0.0029	0.0053	0.00018
Light Liquid	0.0005	0.0005	0.0052	0.00018
Heavy Liquid	0.00007	0.00007	0.00007	0.00018
Compressors	0.5027	0.5027	0.5027	0.1971
Relief Valve (Gas/Vapor)	0.2293	0.2293	0.2293	0.0986
Open-ended Lines[4]	0.0038	0.004	0.0075	0.0033
Sampling Connections[5]	0.033	0.033	0.033	0.033

Notes: All factors are in units of (lb/hr)/component.

1. Factors are taken from EPA Document, EPA-453/R-95-017, November 1995, Page 2-12
2. Factors are TCEQ derived.
3. Control credit is included in the factor; no additional control credit can be applied to these factors. AVO walk-through inspection required.
4. The 28 series quarterly LDAR programs require open-ended lines to be equipped with an appropriate sized cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
5. Use the SOCMI Sampling factor for Non-Leakier. Emission factor is in terms of (lbs/hr)/Sample Taken.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6$ scf$]$ = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

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AB 2588 COMBUSTION EMISSION FACTORS

Emission factors for combustion of natural gas and diesel fuel were developed for use in AB 2588 emission inventory reports in 1990 and updated in 1991, 1992 and 1995. These factors have been updated again based on new data available from the USEPA (1) (10).

These emission factors are to be used where source testing or fuel analysis are not required by the AB 2588 Criteria and Guidelines Regulations, Appendix D. The factors are divided into external combustion sources (boilers, heaters, flares) and internal combustion sources (engines, turbines). Natural gas combustion factors are further divided into a number of sub-categories, based on equipment size and type.

If better source specific data such as manufacturer's data, source tests, or fuel analysis is available, it should be used rather than these emission factors.

Natural Gas Combustion Factors

Natural gas combustion factors were developed for listed substances identified by the California Air Resources Board (CARB) as significant components of natural gas combustion emissions (2) and for some federal HAPs.

In the past, the VCAPCD has included emission factors for natural gas fired internal combustion equipment in this document. In 2000, the USEPA published air toxics emission factors for natural gas fired turbines and engines. For natural gas fired internal combustion equipment, the emission factors from the USEPA publication AP-42 (1) should be used.

For natural gas fired turbines, emission factors from Table 3.1-3 of AP-42, dated April 2000 should be used. For natural gas fired internal combustion engines, emission factors from Tables 3.2-1, 3.2-2, and 3.2-3 of AP-42, dated August 2000, as applicable, should be used.

Natural Gas Fired External Combustion Equipment

	<10 MMBTUh	10-100 MMBTUh	>100 MMBTUh	flare
Pollutant	Emissions (lb/MMcf)			
benzene	0.0080	0.0058	0.0017	0.159
formaldehyde	0.0170	0.0123	0.0036	1.169
PAH's (including naphthalene)	0.0004	0.0004	0.0004	0.014
naphthalene	0.0003	0.0003	0.0003	0.011
acetaldehyde	0.0043	0.0031	0.0009	0.043
acrolein	0.0027	0.0027	0.0008	0.010
propylene	0.7310	0.5300	0.01553	2.440
toluene	0.0366	0.0265	0.0078	0.058
xylenes	0.0272	0.0197	0.0058	0.029
ethyl benzene	0.0095	0.0069	0.0020	1.444
hexane	0.0063	0.0046	0.0013	0.029

External combustion equipment includes boilers, heaters, and steam generators.

Derivation of Factors

The emission factors for boilers, heaters, and steam generators were based on the results of source tests performed mostly on units rated at between 10 and 100 million BTU per hour. The following test data was used: benzene (3) (6) (16) (19); formaldehyde (3) (6) (19); PAH, naphthalene, toluene, xylenes, ethyl benzene (16) (19); acetaldehyde, acrolein, and propylene (19); and hexane (20).

The test results listed above were used directly to determine the emission factors for boilers, heaters, and steam generators with heat input ratings of 10-100 MMBTU/hr. For units <10 MMBTU/hr and >100 MMBTU/hr, were calculated by scaling the factors for 10-100 MMBTU/hr equipment by the ratios of their TOC emission factors (7).

For flares, the factors were developed by applying the CARB species profiles (8) to the USEPA TOC emission factor for flares (1). The internal combustion species profile was used as CARB stated that they had very little confidence in the external combustion profile, and they use only the internal combustion profile (9). Information on acrolein was not contained in the species profile used. It was therefore assumed that the ratio of acrolein to formaldehyde is the same for flares as for turbines. The PAH emission factor is from EPA (10)

Diesel Combustion Factors

Diesel (#1, #2 fuel oil) combustion factors were developed for listed substances identified by the CARB as significant components of diesel fuel combustion emissions (2) and for federal HAPs for which data was available.

Diesel Combustion Factors

	external combustion	internal combustion
Pollutant	Emissions (lb/1000 gal)	
benzene	0.0044	0.1863
formaldehyde	0.3506	1.7261
PAH's (including naphthalene)	0.0498	0.0559
naphthalene	0.0053	0.0197
acetaldehyde	0.3506	0.7833
acrolein	0.3506	0.0339
1,3-butadiene	0.0148	0.2174
chlorobenzene	0.0002	0.0002
dioxins	ND	ND
furans	ND	ND
propylene	0.0100	0.4670
hexane	0.0035	0.0269
toluene	0.0044	0.1054
xylenes	0.0016	0.0424
ethyl benzene	0.0002	0.0109
hydrogen chloride	0.1863	0.1863
arsenic	0.0016	0.0016
beryllium	ND	ND
cadmium	0.0015	0.0015
total chromium	0.0006	0.0006
hexavalent chromium	0.0001	0.0001
copper	0.0041	0.0041
lead	0.0083	0.0083
manganese	0.0031	0.0031
mercury	0.0020	0.0020
nickel	0.0039	0.0039
selenium	0.0022	0.0022
zinc	0.0224	0.0224

ND - not detected

Derivation of Factors

For external combustion equipment, formaldehyde, PAH, and naphthalene emission factors for were developed using source test data (17). Based on information from CARB it was assumed that acetaldehyde and acrolein emissions would be the same as formaldehyde (14). Emission factors for toluene, xylenes, propylene, ethyl benzene, and hexane were based on USEPA emission factors for total organic compounds and CARB species profile (8) for substances identified by CARB as significant.

For internal combustion engines, emission factors for formaldehyde, PAH's, naphthalene, and metals were based on source testing (4), (5), (6), (18). Benzene, acetaldehyde, acrolein, toluene and xylenes emission factors were based on sources (4), (5), and (18). Propylene factors were based on source tests (4) and (5). 1,3-butadiene was based on (4). Ethyl benzene and hexane emission factors were based on (18).

For all oil combustion equipment, emission factors for chlorobenzene, hydrogen chloride, and metals were based on stack testing and fuel analyses (4), (5), (6), (12), (13), (18). It was assumed that 99.9% of the chlorine contained in the fuel was converted to hydrogen chloride (15), with the remainder converted to chlorobenzene. 5% of the chromium in the fuel samples was assumed to be emitted as hexavalent chromium (15).

Dioxins (PCDD's), furans (PCDF's), and beryllium were identified as potentially significant components of diesel combustion exhaust (2). However, the only test results for diesel combustion found (11) reported "not detected" for dioxins and furans. Beryllium has not been detected in any of the diesel fuel analyses reviewed (4), (5), (6), (12), (13), (18). For emission inventory reporting purposes, facilities should report these compounds on for PRO using an emission estimation code of "99" and writing "ND" for the emissions.

References

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(2) Gary Agid, California Air Resources Board, Letter to Air Pollution Control District, September 12, 1989

(3) CARNOT, Emission Inventory Testing at Southern California Edison Company Long Beach Auxiliary Boiler, May 1990

(4) CARNOT, Emissions of Air Toxic Species: Test Conducted Under AB 2588 for the Western States Petroleum Association, May 1990

(5) South Coast Environmental, Compliance Report: Hydraulic Dredge "Ollie Riedel", Report Number T1238C, March 8, 1991

(6) ENSR Consulting and Engineering, Western States Petroleum Association, Pooled Source Report: Oil and Gas Production Combustion Sources, Fresno and Ventura Counties, California, Document Number 7230-007-700, January 1991

(7) Ventura County Air Pollution Control District, Emission Factors and Calculation Procedures, July 1985

(8) State of California Air Resources Board, Identification of Volatile Organic Compound Species Profiles, August 1991, as updated November 29, 2000, profiles 504 and 719

(9) Paul Allen, California Air Resources Board, Telephone conversation, February 1, 1990

(10) United States Environmental Protection Agency, Locating and Estimating Air Emissions From Sources of Polycyclic Organic Matter, EPA-454/R-98-014, July 1998

(11) United States Environmental Protection Agency, Toxic Air Pollutant Emission Factors-A Compilation for Selected Air Toxic Compounds and Sources, EPA-450/2-88-006a, October 1988

(12) BTC Environmental, Inc., Ventura Port District Dredge: Air Toxics Emissions Retesting, January 29, 1991

(13) Shell Western E & P, Emission Inventory Report for Ventura Avenue Field, June 11, 1990

(14) Muriel Strand, California Air Resources Board, Telephone conversation, February 6, 1990

(15) State of California Air Resources Board, Technical Guidance Document to the Criteria and Guidelines Regulation for AB 2588, August 1989

(16) Shell Western E&P, Emission Measurements for Speciated PAH's and BTXE Compounds on a Gas fired Turbine and Steam Generator, June 24-27, 1991

(17) Marine Corps Base Camp Pendleton, California: Draft Final Air Toxics Emissions Inventory Report, May 1, 1991

(18) Entropy Environmentalists, Inc., Pooled Source Testing of a Rig Diesel-Fired Internal Combustion Engine, conducted for Western States Petroleum Association, July 29-31, 1992

(19) Radian Corporation, Source Test Report for the Texaco Heater Treater, the Mobil Steam Generator, and the SWEPI Gas Turbine in the San Joaquin Valley Unified Air Pollution Control District, September 1992

(20) AIRx Testing, Emissions Testing OLS Energu Natural Gas Fired Turbine, and Two Auxiliary Boilers, Job Number 22030, April 21, 1994

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 33 GAS BURNING EQUIPMENT - NITROGEN DIOXIDE

20.2.33.1 ISSUING AGENCY: Environmental Improvement Board.
[11/30/95; 20.2.33.1 NMAC - Rn, 20 NMAC 2.33.100 10/31/02]

20.2.33.2 SCOPE: All geographic areas within the jurisdiction of the Environmental Improvement Board.
[11/30/95; 20.2.33.2 NMAC - Rn, 20 NMAC 2.33.101 10/31/02]

20.2.33.3 STATUTORY AUTHORITY: Environmental Improvement Act, NMSA 1978, section 74-1-8(A)(4) and (7), and Air Quality Control Act, NMSA 1978, sections 74-2-1 et seq., including specifically, section 74-2-5(A), (B) and (C).
[11/30/95; 20.2.33.3 NMAC - Rn, 20 NMAC 2.33.102 10/31/02]

20.2.33.4 DURATION: Permanent.
[11/30/95; 20.2.33.4 NMAC - Rn, 20 NMAC 2.33.103 10/31/02]

20.2.33.5 EFFECTIVE DATE: November 30, 1995.
[11/30/95; 20.2.33.5 NMAC - Rn, 20 NMAC 2.33.104 10/31/02]
[The latest effective date of any section in this Part is 10/31/02.]

20.2.33.6 OBJECTIVE: The objective of this Part is to establish nitrogen dioxide emission standards for gas burning equipment.
[11/30/95; 20.2.33.6 NMAC - Rn, 20 NMAC 2.33.105 10/31/02]

20.2.33.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC (Definitions), as used in this Part:

A. **"Existing gas burning equipment"** means gas burning equipment, the construction or modification of which is commenced prior to February 17, 1972.

B **"New gas burning equipment"** means gas burning equipment, the construction or modification of which is commenced after February 17, 1972.

C. **"Part"** means an air quality control regulation under Title 20, Chapter 2 of the New Mexico Administrative Code, unless otherwise noted; as adopted or amended by the Board.
[11/30/95; 20.2.33.7 NMAC - Rn, 20 NMAC 2.33.107 10/31/02]

20.2.33.8 AMENDMENT AND SUPERSESSION OF PRIOR REGULATIONS: This Part amends and supersedes Air Quality Control Regulation ("AQCR") 604 -- Gas Burning Equipment -- Nitrogen Dioxide last filed on February 17, 1972.

A. All references to AQCR 604 in any other rule shall be construed as a reference to this Part.

B. The amendment and supersession of AQCR 604 shall not affect any administrative or judicial enforcement action pending on the effective date of such amendment nor the validity of any permit issued pursuant to AQCR 604.
[11/30/95; 20.2.33.8 NMAC - Rn, 20 NMAC 2.33.106 10/31/02]

20.2.33.9 to 20.2.33.107 [RESERVED]

20.2.33.108 REQUIREMENTS:

A. The owner or operator of new gas burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit shall not permit, cause, suffer or allow nitrogen dioxide emissions to the atmosphere in excess of 0.2 pounds per million British Thermal Units of heat input.

B. The owner or operator of existing gas burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit shall not permit, cause, suffer or allow nitrogen dioxide emissions to the atmosphere in excess of 0.3 pounds per million British Thermal Units of heat input.
[11/30/95; 20.2.33.108 NMAC - Rn, 20 NMAC 2.33.108 10/31/02]

HISTORY OF 20.2.33 NMAC:
Pre-NMAC History: The material in this part was derived from that previously filed with the Commission of Public Records-State Records Center and Archives.
AQCR 604, Gas Burning Equipment - Nitrogen Dioxide, 02/17/72.

History of Repealed Material: [RESERVED]

Other History:
AQCR 604, Gas Burning Equipment - Nitrogen Dioxide, 02/17/72, was **renumbered** into first version of the New Mexico Administrative Code as 20 NMAC 2.33, Gas Burning Equipment - Nitrogen Dioxide, filed 10/30/95.
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ELECTRONIC CODE OF FEDERAL REGULATIONS

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Title 40 → Chapter I → Subchapter C → Part 98 → Subpart C → §98.33

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart C—General Stationary Fuel Combustion Sources

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§98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

(a) *CO_2 emissions from fuel combustion.* Calculate CO_2 mass emissions by using one of the four calculation methodologies in paragraphs (a)(1) through (a)(4) of this section, subject to the applicable conditions, requirements, and restrictions set forth in paragraph (b) of this section. Alternatively, for units that meet the conditions of paragraph (a)(5) of this section, you may use CO_2 mass emissions calculation methods from part 75 of this chapter, as described in paragraph (a)(5) of this section. For units that combust both biomass and fossil fuels, you must calculate and report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section, except as otherwise provided in paragraphs (a)(5)(iv) and (e) of this section and in §98.36(d).

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C-1, C-1a, or C-1b of this section (as applicable).

(i) Use Equation C-1 except when natural gas billing records are used to quantify fuel usage and gas consumption is expressed in units of therms or million Btu. In that case, use Equation C-1a or C-1b, as applicable.

$$CO_2 = 1 x 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

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where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C-1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) If natural gas consumption is obtained from billing records and fuel usage is expressed in therms, use Equation C-1a.

$$CO_2 = 1 x 10^{-3} [0.1 * Gas * EF] \qquad \text{(Eq. C-1a)}$$

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where:

CO_2 = Annual CO_2 mass emissions from natural gas combustion (metric tons).

Gas = Annual natural gas usage, from billing records (therms).

EF = Fuel-specific default CO_2 emission factor for natural gas, from Table C-1 of this subpart (kg CO_2/mmBtu).

0.1 = Conversion factor from therms to mmBtu

1×10^{-3} = Conversion factor from kilograms to metric tons.

(iii) If natural gas consumption is obtained from billing records and fuel usage is expressed in mmBtu, use Equation C-1b.

$$CO_2 = 1 x 10^{-3} * Gas * EF \qquad \text{(Eq. C-1b)}$$

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where:

CO_2 = Annual CO_2 mass emissions from natural gas combustion (metric tons).

Gas = Annual natural gas usage, from billing records (mmBtu).

EF = Fuel-specific default CO_2 emission factor for natural gas, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) *Tier 2 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C-2a of this section applies to any type of fuel listed in Table C-1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C-2c of this section.

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

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Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in §98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum required sampling frequency for determining the annual average HHV (*e.g.,* monthly, quarterly, semi-annually, or by lot) is specified in §98.34. The method for computing the annual average HHV is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV shall be calculated using Equation C-2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n} (HHV)_i * (Fuel)_i}{\sum_{i=1}^{n} (Fuel)_i} \qquad \text{(Eq. C-2b)}$$

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Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

$(HHV)_I$ = Measured high heat value of the fuel, for month "i" (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per mass or volume).

$(Fuel)_I$ = Mass or volume of the fuel combusted during month "i," from company records (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

n = Number of months in the year that the fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the HHV sampling frequency, the annual average HHV shall either be computed according to paragraph (a)(2)(ii)(A) of this section or as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under §98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C-2c of this section. Equation C-2c of this section may also be used for any other solid fuel listed in Table C-1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1 \times 10^{-3}\, Steam * B * EF \qquad \text{(Eq. C-2c)}$$

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Where:

CO_2 = Annual CO_2 mass emissions from MSW or solid fuel combustion (metric tons).

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C-3 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.91 \qquad \text{(Eq. C-3)}$$

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Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in §98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C-4 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * CC * 0.001 \qquad \text{(Eq. C-4)}$$

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Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C-5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

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Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid or gaseous fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content. You must measure the density using one of the following appropriate methods. You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293-8020, *http://www.ansi.org*), the American Gas Association (AGA), 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824-7000, *http://www.aga.org*), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005-4070, (202) 682-8000, *http://www.api.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356-0060, *http://www.api.org*). The method(s) used shall be documented in the GHG Monitoring Plan required under §98.3(g)(5).

(v) The following default density values may be used for fuel oil, in lieu of using the methods in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) *Tier 4 Calculation Methodology.* Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C-6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18 \times 10^{-7} * C_{CO2} * Q \quad \text{(Eq. C-6)}$$

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Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).

C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18×10^{-7} = Conversion factor (metric tons/scf/% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content using a method described in §75.11(b)(2) of this chapter or use an appropriate default moisture percentage. For coal, wood, and natural gas combustion, you may use the default moisture values specified in §75.11(b)(1) of this chapter. Alternatively, for any type of fuel, you may determine an appropriate site-specific default moisture value (or values), using measurements made with EPA Method 4—Determination Of Moisture Content In Stack Gases, in appendix A-3 to part 60 of this chapter. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. If this option is selected, the site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. For each site-specific default moisture percentage, at least nine Method 4 runs are required, except where the option to use moisture data from a RATA is selected, and the applicable regulation allows a single moisture determination to represent two or more RATA runs. In that case, you may base the site-specific moisture percentage on the number of moisture runs allowed by the RATA regulation. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value shall be updated whenever the owner or operator believes the current value is non-representative, due to changes in unit or process operation, but in any event no less frequently than annually. Use the updated moisture value in the subsequent CO_2 emissions calculations. For each unit operating hour, a moisture correction must be applied to Equation C-6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \quad \text{(Eq. C-7)}$$

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where:

CO_2^* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C-6 of this section, uncorrected (metric tons/hr).

$\%H_2O$ = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations, in accordance with Equation F-14a or F-14b (as applicable) in appendix F to part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products (*i.e.,* no process CO_2 emissions or CO_2 emissions from sorbent are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F-14a and F-14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter, as applicable. If Equation F-14b is used, the hourly moisture percentage in the stack gas shall be determined in accordance with paragraph (a)(4)(iii) of this section.

(v) Each hourly CO_2 mass emission rate from Equation C-6 or C-7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(viii) If a portion of the flue gases generated by a unit subject to Tier 4 (*e.g.,* a slip stream) is continuously diverted from the main flue gas exhaust system for the purpose of heat recovery or some other similar process, and then exhausts through a stack that is not equipped with the continuous emission monitors to measure CO_2 mass emissions, CO_2 emissions shall be determined as follows:

(A) At least once a year, use EPA Methods 2 and 3A, and (if necessary) Method 4 in appendices A-2 and A-3 to part 60 of this chapter to perform emissions testing at a set point that best represents normal, stable process operating conditions. A minimum of three one-hour Method 3A tests are required, to determine the CO_2 concentration. A Method 2 test shall be performed during each Method 3A run, to determine the stack gas volumetric flow rate. If moisture correction is necessary, a Method 4 run shall also be performed during each Method 3A run. Important parametric information related to the stack gas flow rate (*e.g.,* damper positions, fan settings, *etc.*) shall also be recorded during the test.

(B) Calculate a CO_2 mass emission rate (in metric tons/hr) from the stack test data, using a version of Equation C-6 in paragraph (a)(4)(ii) of this section, modified as follows. In the Equation C-6 nomenclature, replace the words "Hourly average" in the definitions of "C_{CO2}" and "Q" with the words "3-run average". Substitute the arithmetic average values of CO_2 concentration and stack gas flow rate from the emission testing into modified Equation C-6. If CO_2 is measured on a dry basis, a moisture correction of the calculated CO_2 mass emission rate is required. Use Equation C-7 in paragraph (a)(4)(ii) of this section to make this correction; replace the word "Hourly" with the words "3-run average" in the equation nomenclature.

(C) The results of each annual stack test shall be used in the GHG emissions calculations for the year of the test.

(D) If, for the majority of the operating hours during the year, the diverted stream is withdrawn at a steady rate at or near the tested set point (as evidenced by fan and damper settings and/or other parameters), you may use the calculated CO_2 mass emission rate from paragraph (a)(4) (viii)(B) of this section to estimate the CO_2 mass emissions for all operating hours in which flue gas is diverted from the main exhaust system. Otherwise, you must account for the variation in the flow rate of the diverted stream, as described in paragraph (c)(4)(viii)(E) of this section.

(E) If the flow rate of the diverted stream varies significantly throughout the year, except as provided below, repeat the stack test and emission rate calculation procedures described in paragraphs (c)(4)(viii)(A) and (c)(4)(viii)(B) of this section at a minimum of two more set points across the range of typical operating conditions to develop a correlation between CO_2 mass emission rate and the parametric data. If additional testing is not feasible, use the following approach to develop the necessary correlation. Assume that the average CO_2 concentration obtained in the annual stack test is the same at all operating set points. Then, beginning with the measured flow rate from the stack test and the associated parametric data, perform an engineering analysis to estimate the stack gas flow rate at two or more additional set points. Calculate the CO_2 mass emission rate at each set point.

(F) Calculate the annual CO_2 mass emissions for the diverted stream as follows. For a steady-state process, multiply the number of hours in which flue gas was diverted from the main exhaust system by the CO_2 mass emission rate from the stack test. Otherwise, using the best available information and engineering judgment, apply the most representative CO_2 mass emission rate from the correlation in paragraph (c)(4)(viii)(E) of this section to determine the CO_2 mass emissions for each hour in which flue gas was diverted, and sum the results. To simplify the calculations, you may count partial operating hours as full hours.

(G) Finally, add the CO_2 mass emissions from paragraph(c)(4)(viii)(F) of this section to the annual CO_2 mass emissions measured by the CEMS at the main stack. Report this sum as the total annual CO_2 mass emissions for the unit.

(H) The exact method and procedures used to estimate the CO_2 mass emissions for the diverted portion of the flue gas exhaust stream shall be documented in the Monitoring Plan required under §98.3(g)(5).

(5) *Alternative methods for certain units subject to Part 75 of this chapter.* Certain units that are not subject to subpart D of this part and that report data to EPA according to part 75 of this chapter may qualify to use the alternative methods in this paragraph (a)(5), in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to appendix D to part 75 of this chapter, but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to part 75 of this chapter, together with Equation G-4 in appendix G to part 75 of this chapter to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F-12 and F-13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to §75.19 of this chapter but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM-11 in §75.19(c)(4)(iii) of this chapter.

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to subpart D of this part, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to part 75 of this chapter, but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F-11 or F-2 (as applicable) in appendix F to part 75 of this chapter to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F-14a or F-14b in appendix F to part 75 of this chapter (as applicable), before applying Equation F-11 or F-2.

(B) Use Equations F-12 and F-13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iv) For units that qualify to use the alternative CO_2 emissions calculation methods in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, if both biomass and fossil fuel are combusted during the year, separate calculation and reporting of the biogenic CO_2 mass emissions (as described in paragraph (e) of this section) is optional, only for the 2010 reporting year, as provided in §98.3(c)(12).

(b) *Use of the four tiers.* Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C-1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C-1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in §98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used. This restriction does not apply to paragraphs (b)(1)(ii), (b)(1)(v), (b)(1)(vi), and (b)(1)(vii) of this section.

(v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms or mmBtu.

(vi) May be used for MSW combustion in a small, batch incinerator that burns no more than 1,000 tons per year of MSW.

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the unit's annual heat input is derived from those fuels, combined. Notwithstanding this requirement, if a unit combusts both MSW and tires and the reporter elects not to separately calculate and report biogenic CO_2 emissions from the combustion of tires, Tier 1 may be used for the MSW combustion, provided that no more than 10 percent of the unit's annual heat input is derived from MSW.

(viii) May be used for the combustion of a fuel listed in Table C-1 if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to §98.36(c)(3), in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr), provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides less than 10 percent of the annual heat input to the unit, or if §98.36(c)(3) applies, to the group of units served by a common supply pipe.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C-1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of natural gas and/or distillate fuel oil.

(iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C-1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C-1 of this subpart (except MSW), unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii), (b)(1)(v), (b)(1)(viii), and (b)(2)(ii) of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C-1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to §98.36(c)(3), in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr), provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3) applies, to the group of units served by a common supply pipe.

(iv) Shall be used when specified in another applicable subpart of this part, regardless of unit size.

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel. Tier 4 may also be used for any group of stationary fuel combustion units, process units, or manufacturing units that share a common stack or duct.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 600 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW as the primary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 600 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(iv) May apply to common stack or duct configurations where:

(A) The combined effluent gas streams from two or more stationary fuel combustion units are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if all of the conditions in paragraph (b)(4)(iv)(A)(1) of this section or if the conditions in paragraph (b)(4)(iv)(A)(2) of this section are met.

(*1*) At least one of the units meets the requirements of paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(C) of this section, and the CEMS installed at the common stack (or duct) meet the requirements of paragraphs (b)(4)(ii)(D) through (b)(4)(ii)(F) of this section.

(*2*) At least one of the units and the monitors installed at the common stack or duct meet the requirements of paragraph (b)(4)(iii) of this section.

(B) The combined effluent gas streams from a process or manufacturing unit and a stationary fuel combustion unit are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if the combustion unit and the monitors installed at the common stack or duct meet the applicability criteria specified in paragraph (b)(4)(iv)(A)(*1*), or (b)(4)(iv)(A)(*2*) of this section.

(C) The combined effluent gas streams from two or more manufacturing or process units are vented through a common stack or duct. In this case, if any of the units is required by an applicable subpart of this part to use Tier 4, the CO_2 mass emissions may be monitored at each individual unit, or the combined CO_2 mass emissions may be monitored at the common stack or duct. However, if it is not feasible to monitor the individual units, the combined CO_2 mass emissions shall be monitored at the common stack or duct.

(5) The Tier 4 Calculation Methodology shall be used:

(i) Starting on January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) No later than January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010. However, if the required CEMS are certified some time in 2010, you need not wait until January 1, 2011 to begin using Tier 4. Rather, you may switch from Tier 2 or Tier 3 to Tier 4 as soon as CEMS certification testing is successfully completed. If this reporting option is chosen, you must document the change in CO_2 calculation methodology in the Monitoring Plan required under §98.3(g)(5) and in the GHG emissions report under §98.3(c). Data recorded by the CEMS during a certification test period in 2010 may be used for reporting under this part, provided that the following two conditions are met:

(A) The certification tests are passed in sequence, with no test failures.

(B) No unscheduled maintenance or repair of the CEMS is performed during the certification test period.

(iii) No later than 180 days following the date on which a change is made that triggers Tier 4 applicability under paragraph (b)(4)(ii) or (b)(4)(iii) of this section (*e.g.,* a change in the primary fuel, manner of unit operation, or installed continuous monitoring equipment).

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) *Calculation of CH_4 and N_2O emissions from stationary combustion sources.* You must calculate annual CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C-2 of this subpart.

(1) Use Equation C-8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2, except when natural gas usage in units of therms or mmBtu is obtained from gas billing records. In that case, use Equation C-8a in paragraph (c)(1)(i) of this section or Equation C-8b in paragraph (c)(1)(ii) of this section (as applicable). For Equation C-8, use the same values for fuel consumption that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \ or \ N_2O = 1 \ x 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

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Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C-1 of this subpart; alternatively, for Tier 3, if actual HHV data are available for the reporting year, you may average these data using the procedures specified in paragraph (a)(2)(ii) of this section, and use the average value in Equation C-8 (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) Use Equation C-8a to calculate CH_4 and N_2O emissions when natural gas usage is obtained from gas billing records in units of therms.

$$CH_4 \ or \ N_2O = 1 \ x \ 10^{-3} * Fuel * 0.1 * EF \qquad \text{(Eq. C-8a)}$$

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where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (therms).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

0.1 = Conversion factor from therms to mmBtu

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) Use Equation C-8b to calculate CH_4 and N_2O emissions when natural gas usage is obtained from gas billing records in units of mmBtu.

CH_4 or $N_2O = 1 \times 10^{-3} * Fuel * EF$ (Eq. C-8b)

where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (mmBtu).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) Use Equation C-9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C-2a of this section to estimate CO_2 emissions. Use the same values for fuel consumption and HHV that you use for the Tier 2 calculation.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * HHV * EF * Fuel \quad \text{(Eq. C-9a)}$$

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Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted during the reporting year.

HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C-9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C-2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio "B" that you use for Equation C-2c.

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3}\ Steam * B * EF \quad \text{(Eq. C-9b)}$$

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Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a solid fuel (metric tons).

Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C-10 of this section for: units subject to subpart D of this part; units that qualify for and elect to use the alternative CO_2 mass emissions calculation methodologies described in paragraph (a)(5) of this section; and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \quad \text{(Eq. C-10)}$$

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Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

$(HI)_A$ = Cumulative annual heat input from combustion of the fuel (mmBtu).

EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C-2 of this section (kg CH_4 or N_2O per mmBtu).

0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, substitute the cumulative annual heat input from combustion of the fuel into Equation C-10 of this section to calculate the annual CH_4 or N_2O emissions. For units in the Acid Rain Program and units that report heat input data to EPA year-round according to part 75 of this chapter, obtain the cumulative annual heat input directly from the electronic data reports required under §75.64 of this chapter. For Tier 4 units, use the best available information, as described in paragraph (c)(4)(ii)(C) of this section, to estimate the cumulative annual heat input $(HI)_A$.

(ii) If more than one type of fuel listed in Table C-2 of this subpart is combusted during the reporting year, use Equation C-10 of this section separately for each type of fuel, except as provided in paragraph (c)(4)(ii)(B) of this section. Determine the appropriate values of $(HI)_A$ as follows:

(A) For units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter, obtain $(HI)_A$ for each type of fuel from the electronic data reports required under §75.64 of this chapter, except as otherwise provided in paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(D) of this section.

(B) For a unit that uses CEMS to monitor hourly heat input according to part 75 of this chapter, the value of $(HI)_A$ obtained from the electronic data reports under §75.64 of this chapter may be attributed exclusively to the fuel with the highest F-factor, when the reporting option in 3.3.6.5 of appendix F to part 75 of this chapter is selected and implemented.

(C) For Tier 4 units, use the best available information (*e.g.,* fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the value of $(HI)_A$ for each type of fuel. Instrumentation used to make these estimates is not subject to the calibration requirements of §98.3(i) or to the QA requirements of §98.34.

(D) Units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter may use the best available information described in paragraph (c)(4)(ii)(C) of this section, to estimate $(HI)_A$ for each fuel type, whenever fuel-specific heat input values cannot be directly obtained from the electronic data reports under §75.64 of this chapter.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C-8, C-8a, C-8b, C-9a, C-9b, or C-10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(6) Calculate the annual CH_4 and N_2O mass emissions from the combustion of blended fuels as follows:

(i) If the mass or volume of each component fuel in the blend is measured before the fuels are mixed and combusted, calculate and report CH_4 and N_2O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass or volume of each component fuel in the blend is not measured before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel "i" that is listed in Table C-2:

(A) Multiply $(\% \text{ Fuel})_i$, the estimated mass or volume percentage (decimal fraction) of component fuel "i", by the total annual mass or volume of the blended fuel combusted during the reporting year, to obtain an estimate of the annual consumption of component "i";

(B) Multiply the result from paragraph (c)(6)(ii)(A) of this section by the HHV of the fuel (default value or, if available, the measured annual average value), to obtain an estimate of the annual heat input from component "i";

(C) Calculate the annual CH_4 and N_2O emissions from component "i", using Equation C-8, C-8a, C-8b, C-9a, or C-10 of this section, as applicable;

(D) Sum the annual CH_4 emissions across all component fuels to obtain the annual CH_4 emissions for the blend. Similarly sum the annual N_2O emissions across all component fuels to obtain the annual N_2O emissions for the blend. Report these annual emissions totals.

(d) *Calculation of CO_2 from sorbent.* (1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection to remove acid gases, if the chemical reaction between the acid gas and the sorbent produces CO_2 emissions, use Equation C-11 of this section to calculate the CO_2 emissions from the sorbent, except when those CO_2 emissions are monitored by CEMS. When a sorbent other than $CaCO_3$ is used, determine site-specific values of R and MW_S.

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S}\right) \qquad \text{(Eq. C-11)}$$

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Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = The number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2).

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons.

(2) The total annual CO_2 mass emissions reported for the unit shall include the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Use the applicable procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels (*i.e.,* either co-fired or blended fuels). Separate reporting of biogenic CO_2 emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in Table C-1 of this section and for municipal solid waste. In addition, when a biomass fuel that is not listed in Table C-1 is combusted in a unit that has a maximum rated heat input greater than 250 mmBtu/hr, if the biomass fuel accounts for 10% or more of the annual heat input to the unit, and if the unit does not use CEMS to quantify its annual CO_2 mass emissions, then, pursuant to §98.33(b)(3)(iii), Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO_2 emissions from combustion of the fuel. Notwithstanding these requirements, in accordance with §98.3(c)(12), separate reporting of biogenic CO_2 emissions is optional for the 2010 reporting year for units subject to subpart D of this part and for units that use the CO_2 mass emissions calculation methodologies in part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic CO_2 emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used. Separate reporting of biogenic CO_2 emissions from the combustion of tires is also optional, but may be reported by following the provisions of paragraph (e)(3) of this section.

(1) You may use Equation C-1 of this subpart to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C-1 of this subpart (except MSW and tires), in a unit of any size, including units equipped with a CO_2 CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under §98.3(g):

(i) Company records.

(ii) The procedures in paragraph (e)(4) of this section.

(iii) The best available information for premixed fuels that contain biomass and fossil fuels (*e.g.,* liquid fuel mixtures containing biodiesel).

(2) You may use the procedures of this paragraph if the following three conditions are met: First, a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions (either according to part 75 of this chapter, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section); second, neither MSW nor tires is combusted in the unit during the reporting year; and third, the CO_2 emissions consist solely of combustion products (*i.e.,* no process or sorbent emissions included).

(i) For each operating hour, use Equation C-12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

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Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf).

$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C-13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C-13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * HHV}{10^6} \qquad \text{(Eq. C-13)}$$

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Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in §98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or a site-specific value determined under section 3.3.6 of appendix F to part 75 (scf CO_2/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in §98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C-14 of this section:

$$\%\ Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

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(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C-14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under §75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to part 75 of this chapter. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) You must use the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section to determine the annual biogenic CO_2 emissions from the combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a CO_2 CEMS, and units for which optional separate reporting of biogenic CO_2 emissions from the combustion of tires is selected.

(i) Use an applicable CO_2 emissions calculation method in this section to quantify the total annual CO_2 mass emissions from the unit.

(ii) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions in the flue gas on a quarterly basis using the method specified in §98.34(d) (for units that combust MSW as the primary fuel or as the only fuel with a biogenic component) or in §98.34(e) (for other units, including units that combust tires).

(iii) Determine the annual biogenic CO_2 mass emissions from the unit by multiplying the total annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from §98.34(d) or §98.34(e), as applicable.

(iv) If the combustion of MSW and/or tires provides no more than 10 percent of the annual heat input to a unit, or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW, you may estimate the annual biogenic CO_2 emissions as follows, in lieu of following the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section:

(A) Calculate the total annual CO_2 emissions from combustion of MSW and/or tires in the unit, using the Tier 1 calculation methodology in paragraph (a)(1) of this section.

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO_2 emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.20.

(4) If Equation C-1 or Equation C-2a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C-15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by §98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \qquad \text{(Eq. C-15)}$$

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Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (Btu/lb).

$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

(5) For units subject to subpart D of this part and for units that use the methods in part 75 of this chapter to quantify CO_2 mass emissions in accordance with paragraph (a)(5) of this section, you may calculate biogenic CO_2 emissions from the combustion of biomass fuels listed in Table C-1 of this subpart using Equation C-15a. This equation may not be used to calculate biogenic CO_2 emissions from the combustion of tires or MSW; the methods described in paragraph (e)(3) of this section must be used for those fuels. Whenever $(HI)_A$, the annual heat input from combustion of biomass fuel in Equation C-15a, cannot be determined solely from the information in the electronic emissions reports under §75.64 of this chapter (*e.g.,* in cases where a unit uses CEMS in combination with multiple F-factors, a worst-case F-factor, or a prorated F-factor to report heat input rather than reporting heat input based on fuel type), use the best available information (as described in §§98.33(c)(4)(ii)(C) and (c)(4)(ii)(D)) to determine $(HI)_A$.

$$CO_2 = 0.001 * (HI)_A * EF \quad \text{(Eq. C-15a)}$$

where:

CO_2 = Annual CO_2 mass emissions from the combustion of a particular type of biomass fuel listed in Table C-1 (metric tons)

$(HI)_A$ = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under §75.64 of this chapter. Where this is not feasible use best available information, as described in §§98.33(c)(4)(ii)(C) and (c)(4)(ii)(D) (mmBtu)

EF = CO_2 emission factor for the biomass fuel, from Table C-1 (kg CO_2/mmBtu)

0.001 = Conversion factor from kg to metric tons

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79140, Dec. 17, 2010; 78 FR 71950, Nov. 29, 2013]

Need assistance?

Table C-1 to Subpart C of Part 98—Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO_2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	61.71
Propane[1]	0.091	62.87
Propylene[2]	0.091	67.77
Ethane[1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene[2]	0.058	65.96
Isobutane[1]	0.099	64.94
Isobutylene[1]	0.103	68.86
Butane[1]	0.103	64.77
Butylene[1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste	9.95[3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
Other fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas[4]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu

Wood and Wood Residuals (dry basis)[5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1]The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2]Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3]Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4]Reporters subject to subpart X of this part that are complying with §98.243(d) or subpart Y of this part may only use the default HHV and the default CO_2 emission factor for fuel gas combustion under the conditions prescribed in §98.243(d)(2)(i) and (d)(2)(ii) and §98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.

[5]Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C-1.

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Table C-2 to Subpart C of Part 98—Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C-1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C-1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C-1, except wood and wood residuals)	3.2×10^{-02}	4.2×10^{-03}
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels—Gaseous (All fuel types in Table C-1)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C-1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the “Energy Industry” or “Manufacturing Industries and Construction”. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC “Energy Industry” category may employ a value of 1g of CH_4/mmBtu.

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ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR data is current as of September 10, 2015

Title 40: Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
Subpart A—General Provision

TABLE A-1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Chemical-Specific GWPs			
Carbon dioxide	124-38-9	CO_2	1
Methane	74-82-8	CH_4	[a]25
Nitrous oxide	10024-97-2	N_2O	[a]298
Fully Fluorinated GHGs			
Sulfur hexafluoride	2551-62-4	SF_6	[a]22,800
Trifluoromethyl sulphur pentafluoride	373-80-8	SF_5CF_3	17,700
Nitrogen trifluoride	7783-54-2	NF_3	17,200
PFC-14 (Perfluoromethane)	75-73-0	CF_4	[a]7,390
PFC-116 (Perfluoroethane)	76-16-4	C_2F_6	[a]12,200
PFC-218 (Perfluoropropane)	76-19-7	C_3F_8	[a]8,830
Perfluorocyclopropane	931-91-9	$C\text{-}C_3F_6$	17,340
PFC-3-1-10 (Perfluorobutane)	355-25-9	C_4F_{10}	[a]8,860
PFC-318 (Perfluorocyclobutane)	115-25-3	$C\text{-}C_4F_8$	[a]10,300
PFC-4-1-12 (Perfluoropentane)	678-26-2	C_5F_{12}	[a]9,160
PFC-5-1-14 (Perfluorohexane, FC-72)	355-42-0	C_6F_{14}	[a]9,300
PFC-6-1-12	335-57-9	C_7F_{16}; $CF_3(CF_2)_5CF_3$	[b]7,820
PFC-7-1-18	307-34-6	C_8F_{18}; $CF_3(CF_2)_6CF_3$	[b]7,620
PFC-9-1-18	306-94-5	$C_{10}F_{18}$	7,500
PFPMIE (HT-70)	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	10,300
Perfluorodecalin (cis)	60433-11-6	$Z\text{-}C_{10}F_{18}$	[b]7,236
Perfluorodecalin (trans)	60433-12-7	$E\text{-}C_{10}F_{18}$	[b]6,288
Saturated Hydrofluorocarbons (HFCs) With Two or Fewer Carbon-Hydrogen Bonds			
HFC-23	75-46-7	CHF_3	[a]14,800
HFC-32	75-10-5	CH_2F_2	[a]675
HFC-125	354-33-6	C_2HF_5	[a]3,500
HFC-134	359-35-3	$C_2H_2F_4$	[a]1,100
HFC-134a	811-97-2	CH_2FCF_3	[a]1,430
HFC-227ca	2252-84-8	$CF_3CF_2CHF_2$	[b]2640
HFC-227ea	431-89-0	C_3HF_7	[a]3,220
HFC-236cb	677-56-5	$CH_2FCF_2CF_3$	1,340
HFC-236ea	431-63-0	CHF_2CHFCF_3	1,370
HFC-236fa	690-39-1	$C_3H_2F_6$	[a]9,810
HFC-329p	375-17-7	$CHF_2CF_2CF_2CF_3$	[b]2360
HFC-43-10mee	138495-42-8	$CF_3CFHCFHCF_2CF_3$	[a]1,640
Saturated Hydrofluorocarbons (HFCs) With Three or More Carbon-Hydrogen Bonds			
HFC-41	593-53-3	CH_3F	[a]92
HFC-143	430-66-0	$C_2H_3F_3$	[a]353
HFC-143a	420-46-2	$C_2H_3F_3$	[a]4,470
HFC-152	624-72-6	CH_2FCH_2F	53
HFC-152a	75-37-6	CH_3CHF_2	[a]124
HFC-161	353-36-6	CH_3CH_2F	12

HFC-245ca	679-86-7	$C_3H_3F_5$	[a]693
HFC-245cb	1814-88-6	$CF_3CF_2CH_3$	[b]4620
HFC-245ea	24270-66-4	$CHF_2CHFCHF_2$	[b]235
HFC-245eb	431-31-2	$CH_2FCHFCF_3$	[b]290
HFC-245fa	460-73-1	$CHF_2CH_2CF_3$	1,030
HFC-263fb	421-07-8	$CH_3CH_2CF_3$	[b]76
HFC-272ca	420-45-1	$CH_3CF_2CH_3$	[b]144
HFC-365mfc	406-58-6	$CH_3CF_2CH_2CF_3$	794
Saturated Hydrofluoroethers (HFEs) and Hydrochlorofluoroethers (HCFEs) With One Carbon-Hydrogen Bond			
HFE-125	3822-68-2	CHF_2OCF_3	14,900
HFE-227ea	2356-62-9	$CF_3CHFOCF_3$	1,540
HFE-329mcc2	134769-21-4	$CF_3CF_2OCF_2CHF_2$	919
HFE-329me3	428454-68-6	$CF_3CFHCF_2OCF_3$	[b]4,550
1,1,1,2,2,3,3-Heptafluoro-3-(1,2,2,2-tetrafluoroethoxy)-propane	3330-15-2	$CF_3CF_2CF_2OCHFCF_3$	[b]6,490
Saturated HFEs and HCFEs With Two Carbon-Hydrogen Bonds			
HFE-134 (HG-00)	1691-17-4	CHF_2OCHF_2	6,320
HFE-236ca	32778-11-3	$CHF_2OCF_2CHF_2$	[b]4,240
HFE-236ca12 (HG-10)	78522-47-1	$CHF_2OCF_2OCHF_2$	2,800
HFE-236ea2 (Desflurane)	57041-67-5	$CHF_2OCHFCF_3$	989
HFE-236fa	20193-67-3	$CF_3CH_2OCF_3$	487
HFE-338mcf2	156053-88-2	$CF_3CF_2OCH_2CF_3$	552
HFE-338mmz1	26103-08-2	$CHF_2OCH(CF_3)_2$	380
HFE-338pcc13 (HG-01)	188690-78-0	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE-43-10pccc (H-Galden 1040x, HG-11)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HCFE-235ca2 (Enflurane)	13838-16-9	CHF_2OCF_2CHFCl	[b]583
HCFE-235da2 (Isoflurane)	26675-46-7	$CHF_2OCHClCF_3$	350
HG-02	205367-61-9	$HF_2C\text{-}(OCF_2CF_2)_2\text{-}OCF_2H$	[b]3,825
HG-03	173350-37-3	$HF_2C\text{-}(OCF_2CF_2)_3\text{-}OCF_2H$	[b]3,670
HG-20	249932-25-0	$HF_2C\text{-}(OCF_2)_2\text{-}OCF_2H$	[b]5,300
HG-21	249932-26-1	$HF_2C\text{-}OCF_2CF_2OCF_2OCF_2O\text{-}CF_2H$	[b]3,890
HG-30	188690-77-9	$HF_2C\text{-}(OCF_2)_3\text{-}OCF_2H$	[b]7,330
1,1,3,3,4,4,6,6,7,7,9,9,10,10,12,12,13,13,15,15-eicosafluoro-2,5,8,11,14-Pentaoxapentadecane	173350-38-4	$HCF_2O(CF_2CF_2O)_4CF_2H$	[b]3,630
1,1,2-Trifluoro-2-(trifluoromethoxy)-ethane	84011-06-3	$CHF_2CHFOCF_3$	[b]1,240
Trifluoro(fluoromethoxy)methane	2261-01-0	CH_2FOCF_3	[b]751
Saturated HFEs and HCFEs With Three or More Carbon-Hydrogen Bonds			
HFE-143a	421-14-7	CH_3OCF_3	756
HFE-245cb2	22410-44-2	$CH_3OCF_2CF_3$	708
HFE-245fa1	84011-15-4	$CHF_2CH_2OCF_3$	286
HFE-245fa2	1885-48-9	$CHF_2OCH_2CF_3$	659
HFE-254cb2	425-88-7	$CH_3OCF_2CHF_2$	359
HFE-263fb2	460-43-5	$CF_3CH_2OCH_3$	11
HFE-263m1; R-E-143a	690-22-2	$CF_3OCH_2CH_3$	[b]29
HFE-347mcc3 (HFE-7000)	375-03-1	$CH_3OCF_2CF_2CF_3$	575
HFE-347mcf2	171182-95-9	$CF_3CF_2OCH_2CHF_2$	374
HFE-347mmy1	22052-84-2	$CH_3OCF(CF_3)_2$	343
HFE-347mmz1 (Sevoflurane)	28523-86-6	$(CF_3)_2CHOCH_2F$	[c]216
HFE-347pcf2	406-78-0	$CHF_2CF_2OCH_2CF_3$	580
HFE-356mec3	382-34-3	$CH_3OCF_2CHFCF_3$	101
HFE-356mff2	333-36-8	$CF_3CH_2OCH_2CF_3$	[b]17
HFE-356mmz1	13171-18-1	$(CF_3)_2CHOCH_3$	27
HFE-356pcc3	160620-20-2	$CH_3OCF_2CF_2CHF_2$	110
HFE-356pcf2	50807-77-7	$CHF_2CH_2OCF_2CHF_2$	265
HFE-356pcf3	35042-99-0	$CHF_2OCH_2CF_2CHF_2$	502
HFE-365mcf2	22052-81-9	$CF_3CF_2OCH_2CH_3$	[b]58
HFE-365mcf3	378-16-5	$CF_3CF_2CH_2OCH_3$	11
HFE-374pc2	512-51-6	$CH_3CH_2OCF_2CHF_2$	557
HFE-449s1 (HFE-7100) Chemical blend	163702-07-6	$C_4F_9OCH_3$	297
	163702-08-7	$(CF_3)_2CFCF_2OCH_3$	
HFE-569sf2 (HFE-7200) Chemical blend	163702-05-4	$C_4F_9OC_2H_5$	59
	163702-06-5	$(CF_3)_2CFCF_2OC_2H_5$	
HG'-01	73287-23-7	$CH_3OCF_2CF_2OCH_3$	[b]222
HG'-02	485399-46-0	$CH_3O(CF_2CF_2O)_2CH_3$	[b]236

HG'-03	485399-48-2	$CH_3O(CF_2CF_2O)_3CH_3$	[b]221
Difluoro(methoxy)methane	359-15-9	CH_3OCHF_2	[b]144
2-Chloro-1,1,2-trifluoro-1-methoxyethane	425-87-6	CH_3OCF_2CHFCl	[b]122
1-Ethoxy-1,1,2,2,3,3,3-heptafluoropropane	22052-86-4	$CF_3CF_2CF_2OCH_2CH_3$	[b]61
2-Ethoxy-3,3,4,4,5-pentafluorotetrahydro-2,5-bis[1,2,2,2-tetrafluoro-1-(trifluoromethyl)ethyl]-furan	920979-28-8	$C_{12}H_5F_{19}O_2$	[b]56
1-Ethoxy-1,1,2,3,3,3-hexafluoropropane	380-34-7	$CF_3CHFCF_2OCH_2CH_3$	[b]23
Fluoro(methoxy)methane	460-22-0	CH_3OCH_2F	[b]13
1,1,2,2-Tetrafluoro-3-methoxy-propane; Methyl 2,2,3,3-tetrafluoropropyl ether	60598-17-6	$CHF_2CF_2CH_2OCH_3$	[b]0.5
1,1,2,2-Tetrafluoro-1-(fluoromethoxy)ethane	37031-31-5	$CH_2FOCF_2CF_2H$	[b]871
Difluoro(fluoromethoxy)methane	461-63-2	CH_2FOCHF_2	[b]617
Fluoro(fluoromethoxy)methane	462-51-1	CH_2FOCH_2F	[b]130
Fluorinated Formates			
Trifluoromethyl formate	85358-65-2	$HCOOCF_3$	[b]588
Perfluoroethyl formate	313064-40-3	$HCOOCF_2CF_3$	[b]580
1,2,2,2-Tetrafluoroethyl formate	481631-19-0	$HCOOCHFCF_3$	[b]470
Perfluorobutyl formate	197218-56-7	$HCOOCF_2CF_2CF_2CF_3$	[b]392
Perfluoropropyl formate	271257-42-2	$HCOOCF_2CF_2CF_3$	[b]376
1,1,1,3,3,3-Hexafluoropropan-2-yl formate	856766-70-6	$HCOOCH(CF_3)_2$	[b]333
2,2,2-Trifluoroethyl formate	32042-38-9	$HCOOCH_2CF_3$	[b]33
3,3,3-Trifluoropropyl formate	1344118-09-7	$HCOOCH_2CH_2CF_3$	[b]17
Fluorinated Acetates			
Methyl 2,2,2-trifluoroacetate	431-47-0	CF_3COOCH_3	[b]52
1,1-Difluoroethyl 2,2,2-trifluoroacetate	1344118-13-3	$CF_3COOCF_2CH_3$	[b]31
Difluoromethyl 2,2,2-trifluoroacetate	2024-86-4	$CF_3COOCHF_2$	[b]27
2,2,2-Trifluoroethyl 2,2,2-trifluoroacetate	407-38-5	$CF_3COOCH_2CF_3$	[b]7
Methyl 2,2-difluoroacetate	433-53-4	HCF_2COOCH_3	[b]3
Perfluoroethyl acetate	343269-97-6	$CH_3COOCF_2CF_3$	[b]2.1
Trifluoromethyl acetate	74123-20-9	CH_3COOCF_3	[b]2.0
Perfluoropropyl acetate	1344118-10-0	$CH_3COOCF_2CF_2CF_3$	[b]1.8
Perfluorobutyl acetate	209597-28-4	$CH_3COOCF_2CF_2CF_2CF_3$	[b]1.6
Ethyl 2,2,2-trifluoroacetate	383-63-1	$CF_3COOCH_2CH_3$	[b]1.3
Carbonofluoridates			
Methyl carbonofluoridate	1538-06-3	$FCOOCH_3$	[b]95
1,1-Difluoroethyl carbonofluoridate	1344118-11-1	$FCOOCF_2CH_3$	[b]27
Fluorinated Alcohols Other Than Fluorotelomer Alcohols			
Bis(trifluoromethyl)-methanol	920-66-1	$(CF_3)_2CHOH$	195
(Octafluorotetramethy-lene) hydroxymethyl group	NA	$X-(CF_2)_4CH(OH)-X$	73
2,2,3,3,3-Pentafluoropropanol	422-05-9	$CF_3CF_2CH_2OH$	42
2,2,3,3,4,4,4-Heptafluorobutan-1-ol	375-01-9	C_3F_7CH2OH	[b]25
2,2,2-Trifluoroethanol	75-89-8	CF_3CH_2OH	[b]20
2,2,3,4,4,4-Hexafluoro-1-butanol	382-31-0	$CF_3CHFCF_2CH_2OH$	[b]17
2,2,3,3-Tetrafluoro-1-propanol	76-37-9	$CHF_2CF_2CH_2OH$	[b]13
2,2-Difluoroethanol	359-13-7	CHF_2CH2OH	[b]3
2-Fluoroethanol	371-62-0	CH_2FCH_2OH	[b]1.1
4,4,4-Trifluorobutan-1-ol	461-18-7	$CF_3(CH_2)_2CH_2OH$	[b]0.05
Unsaturated Perfluorocarbons (PFCs)			
PFC-1114; TFE	116-14-3	$CF_2{=}CF_2$; C_2F_4	[b]0.004
PFC-1216; Dyneon HFP	116-15-4	C_3F_6; $CF_3CF{=}CF_2$	[b]0.05
PFC C-1418	559-40-0	c-C_5F_8	[b]1.97
Perfluorobut-2-ene	360-89-4	$CF_3CF{=}CFCF_3$	[b]1.82
Perfluorobut-1-ene	357-26-6	$CF_3CF_2CF{=}CF_2$	[b]0.10
Perfluorobuta-1,3-diene	685-63-2	$CF_2{=}CFCF{=}CF_2$	[b]0.003
Unsaturated Hydrofluorocarbons (HFCs) and Hydrochlorofluorocarbons (HCFCs)			
HFC-1132a; VF2	75-38-7	$C_2H_2F_2$, $CF_2{=}CH_2$	[b]0.04
HFC-1141; VF	75-02-5	C_2H_3F, $CH_2{=}CHF$	[b]0.02
(E)-HFC-1225ye	5595-10-8	$CF_3CF{=}CHF(E)$	[b]0.06
(Z)-HFC-1225ye	5528-43-8	$CF_3CF{=}CHF(Z)$	[b]0.22

Solstice 1233zd(E)	102687-65-0	$C_3H_2ClF_3$; $CHCl{=}CHCF_3$	[b]1.34
HFC-1234yf; HFO-1234yf	754-12-1	$C_3H_2F_4$; $CF_3CF{=}CH_2$	[b]0.31
HFC-1234ze(E)	1645-83-6	$C_3H_2F_4$; trans-$CF_3CH{=}CHF$	[b]0.97
HFC-1234ze(Z)	29118-25-0	$C_3H_2F_4$; cis-$CF_3CH{=}CHF$; $CF_3CH{=}CHF$	[b]0.29
HFC-1243zf; TFP	677-21-4	$C_3H_3F_3$, $CF_3CH{=}CH_2$	[b]0.12
(Z)-HFC-1336	692-49-9	$CF_3CH{=}CHCF_3$(Z)	[b]1.58
HFC-1345zfc	374-27-6	$C_2F_5CH{=}CH_2$	[b]0.09
Capstone 42-U	19430-93-4	$C_6H_3F_9$, $CF_3(CF_2)_3CH{=}CH_2$	[b]0.16
Capstone 62-U	25291-17-2	$C_8H_3F_{13}$, $CF_3(CF_2)_5CH{=}CH_2$	[b]0.11
Capstone 82-U	21652-58-4	$C_{10}H_3F_{17}$, $CF_3(CF_2)_7CH{=}CH_2$	[b]0.09
Unsaturated Halogenated Ethers			
PMVE; HFE-216	1187-93-5	$CF_3OCF{=}CF_2$	[b]0.17
Fluoroxene	406-90-6	$CF_3CH_2OCH{=}CH_2$	[b]0.05
Fluorinated Aldehydes			
3,3,3-Trifluoro-propanal	460-40-2	CF_3CH_2CHO	[b]0.01
Fluorinated Ketones			
Novec 1230 (perfluoro (2-methyl-3-pentanone))	756-13-8	$CF_3CF_2C(O)CF\ (CF3)_2$	[b]0.1
Fluorotelomer Alcohols			
3,3,4,4,5,5,6,6,7,7,7-Undecafluoroheptan-1-ol	185689-57-0	$CF_3(CF_2)_4CH_2CH_2OH$	[b]0.43
3,3,3-Trifluoropropan-1-ol	2240-88-2	$CF_3CH_2CH_2OH$	[b]0.35
3,3,4,4,5,5,6,6,7,7,8,8,9,9,9-Pentadecafluorononan-1-ol	755-02-2	$CF_3(CF_2)_6CH_2CH_2OH$	[b]0.33
3,3,4,4,5,5,6,6,7,7,8,8,9,9,10,10,11,11,11-Nonadecafluoroundecan-1-ol	87017-97-8	$CF_3(CF_2)_8CH_2CH_2OH$	[b]0.19
Fluorinated GHGs With Carbon-Iodine Bond(s)			
Trifluoroiodomethane	2314-97-8	CF_3I	[b]0.4
Other Fluorinated Compounds			
Dibromodifluoromethane (Halon 1202)	75-61-6	CBR_2F_2	[b]231
2-Bromo-2-chloro-1,1,1-trifluoroethane (Halon-2311/Halothane)	151-67-7	$CHBrClF_3$	[b]41

Fluorinated GHG Group[d]	Global warming potential (100 yr.)
Default GWPs for Compounds for Which Chemical-Specific GWPs Are Not Listed Above	
Fully fluorinated GHGs	10,000
Saturated hydrofluorocarbons (HFCs) with 2 or fewer carbon-hydrogen bonds	3,700
Saturated HFCs with 3 or more carbon-hydrogen bonds	930
Saturated hydrofluoroethers (HFEs) and hydrochlorofluoroethers (HCFEs) with 1 carbon-hydrogen bond	5,700
Saturated HFEs and HCFEs with 2 carbon-hydrogen bonds	2,600
Saturated HFEs and HCFEs with 3 or more carbon-hydrogen bonds	270
Fluorinated formates	350
Fluorinated acetates, carbonofluoridates, and fluorinated alcohols other than fluorotelomer alcohols	30
Unsaturated perfluorocarbons (PFCs), unsaturated HFCs, unsaturated hydrochlorofluorocarbons (HCFCs), unsaturated halogenated ethers, unsaturated halogenated esters, fluorinated aldehydes, and fluorinated ketones	1
Fluorotelomer alcohols	1
Fluorinated GHGs with carbon-iodine bond(s)	1
Other fluorinated GHGs	2,000

[a]The GWP for this compound was updated in the final rule published on November 29, 2013 [78 FR 71904] and effective on January 1, 2014.

[b]This compound was added to Table A-1 in the final rule published on December 11, 2014, and effective on January 1, 2015.

[c]The GWP for this compound was updated in the final rule published on December 11, 2014, and effective on January 1, 2015 .

[d]For electronics manufacturing (as defined in §98.90), the term “fluorinated GHGs” in the definition of each fluorinated GHG group in §98.6 shall include fluorinated heat transfer fluids (as defined in §98.98), whether or not they are also fluorinated GHGs.

[79 FR 73779, Dec. 11, 2014]

Need assistance?

ATLANTIC
ANALYTICAL
LABORATORY

GAS ANALYSIS REPORT

El Paso Electric		AAL Number:	59406-6
100 North Stanton		Received On:	08-Feb-21
El Paso, TX 79901		Report Date:	16-Feb-21
Celena Arreola		PO Number:	171728
Celena.Arreola@epelectric.com			
Sample ID:	Natural Gas - Inter	Sampled On:	29-Jan-21
Sample ID:	Sample Received in AAL Cylinder # 0303	Location:	Rio Grande

Composition (Normalized, % v/v, by ASTM D1945)

Non-Hydrocarbon Gases		**Result**	**D.L.**
Nitrogen:	---	1.76	0.01
Oxygen:	---	–	0.01
Argon:	---	–	0.01
Carbon Dioxide:	---	0.26	0.05
Carbon Monoxide:	---	–	0.05
Hydrogen:	---	–	0.05

Hydrocarbon Gases		**Result**	**D.L.**
Methane:	---	92.83	0.001
Ethylene:	---	nd	0.001
Ethane:	---	4.994	0.001
Propylene:	---	nd	0.001
Propane:	---	0.147	0.001
Isobutane:	---	0.003	0.001
n-Butane:	---	0.003	0.001
Butenes:	---	nd	0.001
Isopentane:	---	nd	0.001
n-Pentane:	---	nd	0.001
Pentenes:	---	nd	0.001
Hexanes +:	---	nd	0.001

	ppm v/v	**D.L.**	**ppm w/w**	**D.L.**	**Grains /100ft^3**	**D.L.**
Total Sulfur (as H_2S)	0.32	0.05	0.64	0.1	0.020	0.003

Total Sulfur determined by ASTM D5504

Elemental Composition (Normalized, % w/w)

Element		Result
Carbon Content (% C, w/w)	---	72.97
Hydrogen Content (% H, w/w)	---	23.64
Oxygen Content (% O, w/w)	---	0.50
Nitrogen Content (% N, w/w)	---	2.89

Heat of Combustion & Physical Properties (by ASTM D3588)

I. @ ASTM Base Conditions; 14.696 psia, 60°F, Dry Gas Format		Result
Net Heat of Combustion	(Lower Heating Value, BTU/ft^3):	928
Gross Heat of Combustion	(Higher Heating Value, BTU/ft^3):	1,030
Gross Heat of Combustion	(Water Saturated Gas Format,BTU/ft^3):	1,012
Net Heat of Combustion	(Lower Heating Value, BTU/lb):	20,642
Gross Heat of Combustion	(Higher Heating Value, BTU/lb):	22,893
Molecular Weight:		17.07
Density (lb/ft^3):		0.0450
Specific Gravity (vs. dry/normal air):		0.5895
Compressibility Factor (z):		0.9978

II. @ ASME Base Conditions; 14.73 psia, 60°F, Dry Gas Format		Result
Net Heat of Combustion	(Lower Heating Value, BTU/ft^3):	930
Gross Heat of Combustion	(Higher Heating Value, BTU/ft^3):	1,032
Gross Heat of Combustion	(Water Saturated Gas Format, BTU/ft^3):	1,014
Net Heat of Combustion	(Lower Heating Value, BTU/lb):	20,642
Gross Heat of Combustion	(Higher Heating Value, BTU/lb):	22,893

NOTES: **D.L.** = Instrumental detection limit for the reported analyte. **nd** = indicates the concentration is less than the accompanying report detection limit. **-** = test not performed. **%** = parts per hundred (percent). **ppm** = parts per million. **ppb** = parts per billion. **w/w** = weight analyte/weight sample format. **v/v** = volume analyte/volume sample format (equivalent to mole fraction for normalized, ideal gas mixtures). Conversions: **0.0001% = 1 ppm = 1,000 ppb**.

Reviewed By,

Ralph Ciotti

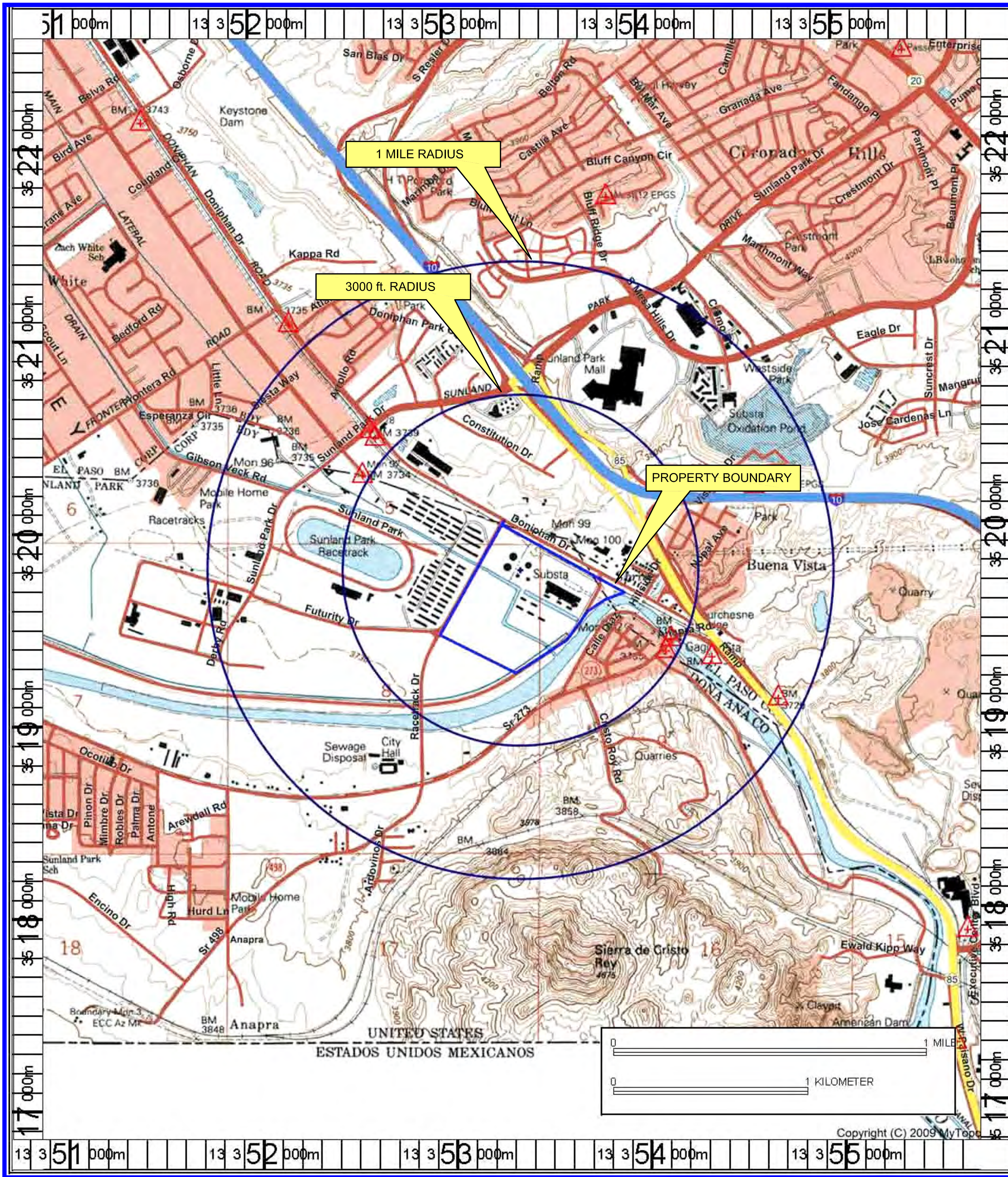
Section 8

Map(s)

A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 0.8km (0.5 miles)	Access and haul roads
Topographic features of the area	Facility property boundaries
The name of the map	The area which will be restricted to public access
A graphical scale	

Refer to attached map.



Map Name: SMELTERTOWN
Map Center: 13 0353319 E 3519680 N
Horizontal Datum: NAD27
Copyright: Copyright (C) 2009 MyTopo

AREA MAP

EL PASO ELECTRIC COMPANY
Rio Grande Generating Station

Air Permit

Dona Ana County, New Mexico

Designed by:	Project No.:	Filename	Date:
Sid Bhardwaj	10169	AREAMAP.DWG	06/01/2010

Section 10

Written Description of the Routine Operations of the Facility

---

<u>A written description of the routine operations of the facility</u>. Include a description of how each piece of equipment will be operated, how controls will be used, and the fate of both the products and waste generated. For modifications and/or revisions, explain how the changes will affect the existing process. In a separate paragraph describe the major process bottlenecks that limit production. The purpose of this description is to provide sufficient information about plant operations for the permit writer to determine appropriate emission sources.

El Paso Electric Company (EPE) owns and operates the Rio Grande Generating Station (Rio Grande) located in the city of Sunland Park in Dona Ana County, New Mexico. EPE currently has an annual production capacity of 340.3 MW that is the result of the Units identified in the following table:

EPN-3, EPN-4, and EPN-1 are three dry bottom wall-fired gas steam boilers with three turbine generator units driven by high pressure, superheated steam producing 245 MW annual average. The only fuel used is pipeline quality natural gas. Unit GT-9 is a simple cycle natural gas fueled turbine and generator that produces an annual average of 95.3 MW. The emissions produced from GT-9 are sent through two different control devices before being sent out the exhaust stack – a selective catalytic reduction (SCR) system to control nitrogen oxide (NOx) emissions and catalytic oxidizer to control carbon monoxide (CO) emissions. Volatile Organic Compounds (VOCs) are also controlled by the catalytic oxidizer when the turbine is operating in low load. Manufacturer operating and maintenance guidance is followed in operation of the turbine and each piece of control equipment. An Induced flue Gas Recirculation System (FGR) is used during EPN-1 (Boiler 8) normal operations to optimize NOx emissions reduction. The only times when Boiler 8 may be operated without full NOx reduction by the FGR system, include the start-up boiler purge cycle and when ambient air temperatures are at or below 48° F.

Section 11

Source Determination

Source submitting under 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC

Sources applying for a construction permit, PSD permit, or operating permit shall evaluate surrounding and/or associated sources (including those sources directly connected to this source for business reasons) and complete this section. Responses to the following questions shall be consistent with the Air Quality Bureau's permitting guidance, Single Source Determination Guidance, which may be found on the Applications Page in the Permitting Section of the Air Quality Bureau website.

Typically, buildings, structures, installations, or facilities that have the same SIC code, that are under common ownership or control, and that are contiguous or adjacent constitute a single stationary source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes. Submission of your analysis of these factors in support of the responses below is optional, unless requested by NMED.

A. Identify the emission sources evaluated in this section (list and describe)**:**
Refer to Table 2-A

B. Apply the 3 criteria for determining a single source:

SIC Code: Surrounding or associated sources belong to the same 2-digit industrial grouping (2-digit SIC code) as this facility, OR surrounding or associated sources that belong to different 2-digit SIC codes are support facilities for this source.

☒ **Yes** ☐ **No**

Common Ownership or Control: Surrounding or associated sources are under common ownership or control as this source.

☒**Yes** ☐ **No**

Contiguous or Adjacent: Surrounding or associated sources are contiguous or adjacent with this source.

☒ **Yes** ☐ **No**

C. Make a determination:

☒ The source, as described in this application, constitutes the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes. If in "A" above you evaluated only the source that is the subject of this application, all "**YES**" boxes should be checked. If in "A" above you evaluated other sources as well, you must check **AT LEAST ONE** of the boxes "**NO**" to conclude that the source, as described in the application, is the entire source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes.

☐ The source, as described in this application, **does not** constitute the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes (A permit may be issued for a portion of a source). The entire source consists of the following facilities or emissions sources (list and describe):

Section 12

Section 12.A

PSD Applicability Determination for All Sources

(Submitting under 20.2.72, 20.2.74 NMAC)

A PSD applicability determination for all sources. For sources applying for a significant permit revision, apply the applicable requirements of 20.2.74.AG and 20.2.74.200 NMAC and to determine whether this facility is a major or minor PSD source, and whether this modification is a major or a minor PSD modification. It may be helpful to refer to the procedures for Determining the Net Emissions Change at a Source as specified by Table A-5 (Page A.45) of the EPA New Source Review Workshop Manual to determine if the revision is subject to PSD review.

A. This facility is:

- ☐ **a minor PSD source before and after this modification (if so, delete C and D below).**
- ☐ **a major PSD source before this modification. This modification will make this a PSD minor source.**
- ☐ **an existing PSD Major Source that has never had a major modification requiring a BACT analysis.**
- ☐ **an existing PSD Major Source that has had a major modification requiring a BACT analysis**
- ☐ **a new PSD Major Source after this modification.**

B. **This facility [is or is not] one of the listed 20.2.74.501 Table I – PSD Source Categories. The "project" emissions** for this modification are **[significant or not significant]. [Discuss why.] The "project" emissions listed below [do or do not] only result from changes described in this permit application, thus no emissions from other [revisions or modifications, past or future] to this facility. Also, specifically discuss whether this project results in "de-bottlenecking", or other associated emissions resulting in higher emissions. The project emissions (before netting) for this project are as follows [see Table 2 in 20.2.74.502 NMAC for a complete list of significance levels]:**

a. **NOx: XX.X TPY**
b. **CO: XX.X TPY**
c. **VOC: XX.X TPY**
d. **SOx: XX.X TPY**
e. **PM: XX.X TPY**
f. **PM10: XX.X TPY**
g. **PM2.5: XX.X TPY**
h. **Fluorides: XX.X TPY**
i. **Lead: XX.X TPY**
j. **Sulfur compounds (listed in Table 2): XX.X TPY**
k. **GHG: XX.X TPY**

C. **Netting [is required, and analysis is attached to this document.] OR [is not required (project is not significant)] OR [Applicant is submitting a PSD Major Modification and chooses not to net.]**

D. **BACT** is **[not required for this modification, as this application is a minor modification.] OR [required, as this application is a major modification. List pollutants subject to BACT review and provide a full top down BACT determination.]**

E. If this is an existing PSD major source, or any facility with emissions greater than 250 TPY (or 100 TPY for 20.2.74.501 Table 1 – PSD Source Categories), determine whether any permit modifications are related, or could be considered a single project with this action, and provide an explanation for your determination whether a PSD modification is triggered.

This is a Title V Permit renewal application being submitted under 20.2.70.300 NMAC, therefore section 12.B does not apply.

Section 13

Determination of State & Federal Air Quality Regulations

This section lists each state and federal air quality regulation that may apply to your facility and/or equipment that are stationary sources of regulated air pollutants.

Not all state and federal air quality regulations are included in this list. Go to the Code of Federal Regulations (CFR) or to the Air Quality Bureau's regulation page to see the full set of air quality regulations.

Required Information for Specific Equipment:
For regulations that apply to specific source types, in the 'Justification' column **provide any information needed to determine if the regulation does or does not apply**. **For example**, to determine if emissions standards at 40 CFR 60, Subpart IIII apply to your three identical stationary engines, we need to know the construction date as defined in that regulation; the manufacturer date; the date of reconstruction or modification, if any; if they are or are not fire pump engines; if they are or are not emergency engines as defined in that regulation; their site ratings; and the cylinder displacement.

Required Information for Regulations that Apply to the Entire Facility:
See instructions in the 'Justification' column for the information that is needed to determine if an 'Entire Facility' type of regulation applies (e.g. 20.2.70 or 20.2.73 NMAC).

Regulatory Citations for Regulations That Do Not, but Could Apply:
If there is a state or federal air quality regulation that does not apply, but you have a piece of equipment in a source category for which a regulation has been promulgated, you must **provide the low level regulatory citation showing why your piece of equipment is not subject to or exempt from the regulation. For example** if you have a stationary internal combustion engine that is not subject to 40 CFR 63, Subpart ZZZZ because it is an existing 2 stroke lean burn stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, your citation would be 40 CFR 63.6590(b)(3)(i). **We don't want a discussion of every non-applicable regulation, but if it is possible a regulation could apply, explain why it does not. For example,** if your facility is a power plant, you do not need to include a citation to show that 40 CFR 60, Subpart OOO does not apply to your non-existent rock crusher.

Regulatory Citations for Emission Standards:
For each unit that is subject to an emission standard in a source specific regulation, such as 40 CFR 60, Subpart OOO or 40 CFR 63, Subpart HH, include the low level regulatory citation of that emission standard. Emission standards can be numerical emission limits, work practice standards, or other requirements such as maintenance. **Here are examples:** a glycol dehydrator is subject to the general standards at 63.764C(1)(i) through (iii); an engine is subject to 63.6601, Tables 2a and 2b; a crusher is subject to 60.672(b), Table 3 and all transfer points are subject to 60.672(e)(1)

Federally Enforceable Conditions:
All federal regulations are federally enforceable. All Air Quality Bureau State regulations are federally enforceable except for the following: affirmative defense portions at 20.2.7.6.B, 20.2.7.110(B)(15), 20.2.7.11 through 20.2.7.113, 20.2.7.115, and 20.2.7.116; 20.2.37; 20.2.42; 20.2.43; 20.2.62; 20.2.63; 20.2.86; 20.2.89; and 20.2.90 NMAC. Federally enforceable means that EPA can enforce the regulation as well as the Air Quality Bureau and federally enforceable regulations can count toward determining a facility's potential to emit (PTE) for the Title V, PSD, and nonattainment permit regulations.

INCLUDE ANY OTHER INFORMATION NEEDED TO COMPLETE AN APPLICABILITY DETERMINATION OR THAT IS RELEVENT TO YOUR FACILITY'S NOTICE OF INTENT OR PERMIT.

EPA Applicability Determination Index for 40 CFR 60, 61, 63, etc: http://cfpub.epa.gov/adi/

Table for STATE REGULATIONS:

STATE REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
20.2.1 NMAC	General Provisions	Yes	Facility	The provisions of this part apply to all the parts of this facility.
20.2.3 NMAC	Ambient Air Quality Standards NMAAQS	Yes	Facility	If subject, this would normally apply to the entire facility. 20.2.3 NMAC is a State Implementation Plan (SIP) approved regulation that limits the maximum allowable concentration of, Sulfur Compounds, Carbon Monoxide and Nitrogen Dioxide. Title V applications, see exemption at 20.2.3.9 NMAC The TSP NM ambient air quality standard was repealed by the EIB effective November 30, 2018.
20.2.7 NMAC	Excess Emissions	Yes	Facility	All Title V major sources are subject to Air Quality Control Regulations, as defined in 20.2.7 NMAC, and are thus subject to the requirements of this regulation. Also listed as applicable in NSR Permit 1554-M1R3.
20.2.23 NMAC	Fugitive Dust Control	No	Facility	This regulation may apply if, this is an application for a notice of intent (NOI) per 20.2.73 NMAC, if the activity or facility is a fugitive dust source listed at 20.2.23.108.A NMAC, **and** if the activity or facility is located in an area subject to a mitigation plan pursuant to 40 CFR 51.930. http://164.64.110.134/parts/title20/20.002.0023.html As of January 2019, the only areas of the State subject to a mitigation plan per 40 CFR 51.930 are in Doña Ana and Luna Counties. Sources exempt from 20.2.23 NMAC are activities and facilities subject to a permit issued pursuant to the NM Air Quality Control Act, the Mining Act, or the Surface Mining Act (20.2.23.108.B NMAC. **20.2.23.108 APPLICABILITY:** **A.** This part shall apply to persons owning or operating the following fugitive dust sources in areas requiring a mitigation plan in accordance with 40 CFR Part 51.930: **(1)** disturbed surface areas or inactive disturbed surface areas, or a combination thereof, encompassing an area equal to or greater than one acre; **(2)** any commercial or industrial bulk material processing, handling, transport or storage operations. **B.** The following fugitive dust sources are exempt from this part: **(1)** agricultural facilities, as defined in this part; **(2)** roadways, as defined in this part; **(3)** operations issued permits pursuant to the state of New Mexico Air Quality Control Act, Mining Act or Surface Mining Act; and **(4)** lands used for state or federal military activities. [20.2.23.108 NMAC - N, 01/01/2019]
20.2.33 NMAC	Gas Burning Equipment - Nitrogen Dioxide	Yes	EPN-1, EPN-3 EPN-4	**This regulation does not apply to internal combustion equipment such as engines. It only applies to external combustion equipment such as heaters or boilers.** **Choose all that apply:** This facility has new gas burning equipment **(external combustion emission sources, such as gas fired boilers and heaters)** having a heat input of greater than 1,000,000 million British Thermal Units per year per unit This facility has existing gas burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit Note: "New gas burning equipment" means gas burning equipment, the construction or modification of which is commenced after February 17, 1972.
20.2.34 NMAC	Oil Burning Equipment: NO_2	No		**This regulation does not apply to internal combustion equipment such as engines. It only applies to external combustion equipment such as heaters or boilers.**

STATE REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
				This facility has oil burning equipment **(external combustion emission sources, such as oil fired boilers and heaters)** having a heat input of greater than 1,000,000 million British Thermal Units per year per unit.
20.2.35 NMAC	Natural Gas Processing Plant – Sulfur	No		This regulation could apply to existing (prior to July 1, 1974) or new (on or after July 1, 1974) natural gas processing plants that use a Sulfur Recovery Unit to reduce sulfur emissions. **See 'Guidance and Clarification Regarding Applicability of 20.2.35 NMAC' located with the Air Quality Bureau's Permit Section website guidance documents.**
20.2.37 and 20.2.36 NMAC	Petroleum Processing Facilities and Petroleum Refineries	N/A	N/A	**These regulations were repealed by the Environmental Improvement Board. If you had equipment subject to 20.2.37 NMAC before the repeal, your combustion emission sources are now subject to 20.2.61 NMAC.**
20.2.38 NMAC	Hydrocarbon Storage Facility	No		This regulation could apply to storage tanks at petroleum production facilities, processing facilities, tanks batteries, or hydrocarbon storage facilities.
20.2.39 NMAC	Sulfur Recovery Plant - Sulfur	No		This regulation could apply to sulfur recovery plants that are not part of petroleum or natural gas processing facilities.
20.2.61.109 NMAC	Smoke & Visible Emissions	Yes	EPN-1, EPN-3, EPN-4, GT-9	The boilers (EPN-1,-3,-4) as well as the natural gas turbine (GT- 9) are subjected to this regulation burning natural gas. Stack emissions shall not exceed 20% opacity.
20.2.70 NMAC	Operating Permits	Yes	Facility	This is a major source for NOx and CO.
20.2.71 NMAC	Operating Permit Fees	Yes	Facility	Yes, this facility is subject to 20.2.70 NMAC and is in turn subject to 20.2.71 NMAC.
20.2.72 NMAC	Construction Permits	Yes	EPN-1, EPN-3, EPN-4, GT-9	This facility is subject to 20.2.72 NMAC and NSR Permit number: NSR Permit 1554-M1R3
20.2.73 NMAC	NOI & Emissions Inventory Requirements	Yes	Facility	This installation is a Title V source. It operates in accordance with TV Permit No: P127-R3. Therefore, this regulation applies to this facility. NOI: 20.2.73.200 NMAC applies (requiring a NOI application) Emissions Inventory Reporting: 20.2.73.300 NMAC applies. All Title V major sources meet the applicability requirements of 20.2.73.300 NMAC.
20.2.74 NMAC	Permits – Prevention of Significant Deterioration (PSD)	No	Facility	This application is being submitted for the renewal of the Title V permit P127-R3. Since emissions are not being modified, the SER have not been exceeded, this facility is not subject to comply with the regulations promulgated under this rule., as of August 7, 1980, is being regulated under section 111 or 112 of the Act.
20.2.75 NMAC	Construction Permit Fees	Yes	EPN-1, EPN-3, EPN-4, GT-9	This facility is subject to 20.2.72 NMAC and is in turn subject to 20.2.75 NMAC. N/A if subject to 20.2.71 NMAC.
20.2.77 NMAC	New Source Performance	Yes	GT-9	This is a stationary source which is subject to the requirements of 40 CFR Part 60, as amended through September 23, 2013. Source GT-9 is a Stationary Gas Turbine subjected to Subpart KKKK of 40 CFR Part 60 as amended through November 20, 2006

STATE REGU-LATIONS CITATION	**Title**	**Applies? Enter Yes or No**	**Unit(s) or Facility**	**JUSTIFICATION:** **(You may delete instructions or statements that do not apply in the justification column to shorten the document.)**
20.2.78 NMAC	Emission Standards for HAPS	No		This facility is not a major source of hazardous air pollutants.
20.2.79 NMAC	Permits – Nonattainment Areas	No	Facility	This application is being submitted for the renewal of the Title V permit P127R3. Since emissions are not being modified, the SER have not been exceeded, this facility is not subject to comply with the regulations promulgated under this rule.
20.2.80 NMAC	Stack Heights	No		Boilers 6, 7, and 8, as well as GT-9 adhere to good engineering practices.
20.2.82 NMAC	MACT Standards for source categories of HAPS	No	EPN-1	This regulation does not apply to the emission units since this installation does not emit hazardous air pollutants in quantities which would make it subject to the requirements of 40 CFR Part 63, as amended through November 30, 2006.
20.2.84 NMAC	Acid Rain Permits	Yes	EPN-3, EPN-4, GT-9	This facility is subject to 40 CFR 72 (Acid Rain Program).

Table for Applicable FEDERAL REGULATIONS (Note: This is not an exhaustive list):

FEDERAL REGU-LATIONS CITATION	**Title**	**Applies? Enter Yes or No**	**Unit(s) or Facility**	**JUSTIFICATION:**
40 CFR 50	NAAQS	Yes	Facility	If subject, this would normally apply to the entire facility. This applies if you are subject to 20.2.70, 20.2.72, 20.2.74, and/or 20.2.79 NMAC.
NSPS 40 CFR 60, Subpart A	General Provisions	Yes	GT-9, EG-1, SE-1	Unit GT-9, EG-1, and SE-1 are subjected to Subpart KKKK – Standard Performance for Stationary Combustion Turbines.
NSPS 40 CFR60.40a, Subpart Da	Subpart Da, Performance Standards for **Electric Utility Steam Generating Units**	No		This facility does not have units classified as Electric Utility Steam Generating Units. Therefore, this regulation does not apply to this site.

FEDERAL REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION:
NSPS 40 CFR60.40b Subpart Db	**Electric Utility Steam Generating Units**	No		This facility does not have units classified as Electric Utility Steam Generating Units. Therefore, this regulation does not apply to this site.
40 CFR 60.40c, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	No		This facility does not have units classified as Electric Utility Steam Generating Units. Therefore, this regulation does not apply to this site.
NSPS 40 CFR 60, Subpart Ka	Standards of Performance for **Storage Vessels for Petroleum Liquids** for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and **Prior** to July 23, 1984	No		This facility does not have storage tanks with a capacity greater than 151,416 liters (40,000 gallons) used to store petroleum liquids for which construction is commenced after May 18, 1978. Therefore, this regulation does not apply to this site.
NSPS 40 CFR 60, Subpart Kb	Standards of Performance for **Volatile Organic Liquid Storage Vessels** (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced **After** July 23, 1984	No		This facility does not have has storage vessels with a capacity greater than or equal to 75 cubic meters (m 3) used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Therefore, this regulation does not apply to this site.
NSPS 40 CFR 60.330 Subpart GG	**Stationary Gas Turbines**	No		Exempt from this subpart since Subpart KKKK is applicable. Refer to Subpart KKKK for additional information. This turbine was constructed and installed after February 18, 2005, thus it is exempt under this subpart.5
NSPS 40 CFR 60, Subpart KKK	Leaks of VOC from **Onshore Gas Plants**	No		This facility is not an Onshore Gas Plant. Therefore, this regulation does not apply to this facility.
NSPS 40 CFR Part 60 Subpart LLL	Standards of Performance for **Onshore Natural Gas Processing**:	No		The facility is not an onshore gas plant. Therefore, this regulation does not apply to this site.

FEDERAL REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION:
	SO_2 Emissions			
NSPS 40 CFR Part 60 Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which construction, modification or reconstruction commenced after August 23, 2011 and before September 18, 2015	No		This facility does not process, transmits and/or distributes crude oil and/or natural gas. Therefore, this regulation does not apply to this site.
NSPS 40 CFR Part 60 Subpart OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015	No		This facility does not process, transmit, and/or distribute crude oil and/or natural gas. Therefore, this regulation does not apply to this site.
NSPS 40 CFR 60 Subpart IIII	Standards of performance for Stationary Compression Ignition Internal Combustion Engines	Yes	EG-1, SE-1	This regulation applies to the emergency generator and emergency fire water pump within the facility.
NSPS 40 CFR Part 60 Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines			This facility does not operate any regulated spark ignition internal combustion engines. Therefore, this regulation does not apply to this installation.
NSPS 40 CFR 60 Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	No		GHG standards included in this subpart apply to any steam generating unit, IGCC, or stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014. This facility includes no such units.
NSPS 40 CFR 60 Subpart UUUU	Emissions Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units	No		
NSPS 40 CFR 60, Subparts WWW, XXX, Cc,	Standards of performance for Municipal Solid Waste (MSW)	No		This facility is not a MSW or landfill.

FEDERAL REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION:
and Cf	Landfills			
NESHAP 40 CFR 61 Subpart A	General Provisions	No	Units Subject to 40 CFR 61	This facility does not generate hazardous air pollutants (HAP) in quantities exceeding NESHAP emission thresholds. Therefore, this regulation does not apply to this site.
NESHAP 40 CFR 61 Subpart E	National Emission Standards for **Mercury**	No		The provisions of this subpart do not apply to this facility since it does not process mercury ore to recover mercury, nor uses mercury chlor-alkali cells to produce chlorine gas and/or alkali metal hydroxide. In addition, it does not operate any activity related to incineration and/or dry wastewater treatment for plant sludge.
NESHAP 40 CFR 61 Subpart V	National Emission Standards for **Equipment Leaks** (Fugitive Emission Sources)	No		The provisions of this subpart do not apply to this facility since it does not operate any of the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart. VHAP service means a piece of equipment that either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight of VHAP. VHAP means a substance regulated under this subpart for which a standard for equipment leaks of the substance has been promulgated. Benzene is a VHAP (See 40 CFR 61 Subpart J). Thus, based on the above, this regulation does not apply to this site.
MACT 40 CFR 63, Subpart A	General Provisions	Yes	EG-1, SE-1	This regulation applies to the emergency generator and emergency fire water pump within the facility.
MACT 40 CFR 63.760 Subpart HH	**Oil and Natural Gas Production Facilities**	No		This facility is not subject to the requirements of 40 CFR 63 Subpart HH because it is not an Oil and Natural Gas Production Facility.
MACT 40 CFR 63 Subpart HHH		No		This facility is not subject to the requirements of this subpart since this site is not classified as a natural gas transmission and storage facility that transports or stores natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in §63.1271
MACT 40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Industrial, Commercial, and Institutional Boilers & Process Heaters	No		Not a major source of HAPs.
MACT 40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants Coal & Oil Fire Electric Utility Steam Generating Unit	No		This facility does not include Coal nor Oil fired units.
MACT 40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for	Yes	EG-1, SE-1	This facility has a standby emergency generator and emergency fire water pump that comply with 40 CFR 63 by complying with NSPS 40 CFR 60 Subpart IIII.

FEDERAL REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION:
	Stationary Reciprocating Internal Combustion Engines (**RICE MACT**)			
40 CFR 64	**Compliance Assurance Monitoring**	No		Emission units EPN-3 (Boiler 6), EPN-4 (Boiler 7), EPN-1 (Boiler 8) and GT-9 are monitored with continuous emission monitors for NOx and CO. Part 64.2(b)(vi) specifies that emission limitations or standards for which a Part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1, are exempt from Compliance Assurance Monitoring (CAM) requirements.
40 CFR 68	**Chemical Accident Prevention**	No		This facility uses chlorine in 150-lb cylinders for its cooling towers, but does not have more than the threshold quantity of chlorine in each process (cooling tower), as determined under §68.115. Emission unit (GT-9) uses 19% aqueous ammonia as part of the SCR system for NOx control. Although ammonia is stored in a 20,000-gallon tank it is less than the 20% threshold.
Title IV – Acid Rain 40 CFR 72	**Acid Rain**	Yes	EPN-1, EPN-3, EPN-4, GT-9	This regulation applies to all the mentioned units.
Title IV – Acid Rain 40 CFR 73	**Sulfur Dioxide** Allowance Emissions	Yes	EPN-1, EPN-3, EPN-4, GT-9	This regulation applies to all the mentioned units.
Title IV-Acid Rain 40 CFR 75	**Continuous Emissions Monitoring**	Yes	EPN-1, EPN-3, EPN-4, GT-9	This regulation applies to all the mentioned emission units since they are covered under Acid Rain Program regulations and because they meet the requirements under 40 CFR 75.2.
Title IV – Acid Rain 40 CFR 76	**Acid Rain** Nitrogen Oxides **Emission Reduction Program**	No	N/A	This facility does not have any coal-fired utility units, therefore, this regulation does not apply to this installation.
Title VI – 40 CFR 82	Protection of **Stratospheric Ozone**	No	N/A	This facility does not “service”, “maintain” or “repair” class I or class II appliances nor “disposes” of the appliances. Also, this installation does not operate any disposal activity as defined below. Disposal definition in 82.152: Disposal means the process leading to and including: (1) The discharge, deposit, dumping or placing of any discarded appliance into or on any land or water; (2) The disassembly of any appliance for discharge, deposit, dumping or placing of its discarded component parts into or on any land or water; or (3) The disassembly of any appliance for reuse of its component parts. “Major maintenance, service, or repair means” any maintenance, service, or repair that involves the removal of any or all of the following appliance components: compressor, condenser, evaporator, or auxiliary heat exchange coil; or any maintenance, service, or repair that involves uncovering an opening of more than four (4) square inches of “flow

FEDERAL REGU-LATIONS CITATION	Title	Applies? Enter Yes or No	Unit(s) or Facility	JUSTIFICATION:
				area" for more than 15 minutes. Therefore, this regulation does not apply.
Title IV – Acid Rain 40 CFR 77	Excess Emission	Yes	EPN-1, EPN-3, EPN-4, GT-9	This regulation applies to all the emission units that are covered by the Acid Rain Program regulation.
CAA Section 112(r)	Accidental Release Prevention / Risk Management Plan Rule	No		This facility uses chlorine in 150-lb cylinders as a biocide for its cooling towers, but does not have more than the threshold quantity of chlorine in each process (cooling tower), as determined under §68.115. Emission unit (GT-9) uses 19% aqueous ammonia as part of the SCR system for NOx control. Although ammonia is stored in a 20,000-gallon tank that exceeds the threshold quantity of 20,000 lb, 40 CFR 68 only applies when the aqueous ammonia concentration is 20% or more. Thus, the Chemical Accident Prevention provisions do not apply to this site.

Section 14

Operational Plan to Mitigate Emissions

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

☒ **Title V Sources** (20.2.70 NMAC)**:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Emissions During Startups, Shutdowns, and Emergencies** defining the measures to be taken to mitigate source emissions during startups, shutdowns, and emergencies as required by 20.2.70.300.D.5(f) and (g) NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☐ **NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Source Emissions During Malfunction, Startup, or Shutdown** defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown as required by 20.2.72.203.A.5 NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☒ **Title V** (20.2.70 NMAC)**, NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has established and implemented a Plan to Minimize Emissions During Routine or Predictable Startup, Shutdown, and Scheduled Maintenance through work practice standards and good air pollution control practices as required by 20.2.7.14.A and B NMAC. This plan shall be kept on site or at the nearest field office to be made available to the Department upon request. This plan should not be submitted with this application.

Rio Grande Generating Facility consists of several emissions sources. El Paso Electric Company (EPEC) has standard operating procedures (SOPs) which establish operational procedures for the equipment and which serve to mitigate emissions during startups, shutdowns, maintenance, and emergency events. These SOPs establish good work practices and good air pollution control practices, and fulfill the requirements of both 20.2.70.300.D.5 (f) and (g) NMAC, and 20.2.7.14.A and B NMAC. The SOPs are distributed appropriately throughout the facility, and are not comprised of a single document. EPEC notes that the permitted emissions limits apply during periods of startup, shutdown, and maintenance; excess emissions are not expected to occur during these events.

Rio Grande Station
Plan to Minimize Emissions during Routine or Predictable Startup, Shutdown & Scheduled Maintenance

This plan will be used to minimize emissions during routine or predictable startup, shutdown, and scheduled maintenance (SSM) through work practice standards and good air pollution control practices as defined below. Air emission limits, as defined in air permits issued by New Mexico Environment Department (NMED), will apply during SSM periods. These procedures shall apply to units 6, 7, 8 and GT-9.

1. Unit operators shall be knowledgeable of and vigilant of short term permit limits.

2. Regular inspections of CEMS data will be performed by operators during SSM periods.

3. Use of available air pollution control equipment and proper air/fuel mixtures will be put into effect to ensure that exceedances are minimized using good work practices.

4. A Continuous Emissions Monitoring System (CEMS) will be used to monitor and record emissions on a continuous basis. Periodic certification of the CEMS will be conducted by use of a Relative Accuracy Test Audit (RATA).

5. In the event that unit operators suspect an exceedance of any of the emissions as defined by the air permits, an event will be logged in their log sheets following corrective measures taken to correct the suspected exceedance. A description of corrective measures will be entered into the operator's log book.

6. In the event that unit operators suspect an exceedance of any of the emissions as defined by the air permits, unit operators will inform plant management as well as personnel and management of the Environment Department. Communication to all parties will be both verbal and via email. The report by the plant operators should include date and time of suspected incident, the pollutant, and the affected unit.

7. In the event that a suspected emission exceedance notification is received by the Environment Department, an engineer/scientist will investigate the incident and report the finding back to plant personnel and management. In the event that the suspected exceedance is an actual exceedance, the engineer/scientist will contact plant personnel, investigate the cause of the exceedance and together with plant personnel determine how future exceedances could be prevented.

8. Personnel from the Environment Department will report verified exceedance to NMED as required by the applicable permit.

Definitions:

"Air pollutant" means an air pollution agent or combination of such agents, including any physical, chemical, biological, radioactive (including source material, special nuclear material, and byproduct material) substance or matter which is emitted into or otherwise enters the ambient air. Such term includes any precursors to the formation of any air pollutant, to the extent the administrator has identified such precursor or precursors for the particular purpose for which the term "air pollutant" is used. This excludes water vapor, nitrogen (N2), carbon dioxide (CO2), oxygen (O2), methane and ethane.

"Air pollution control equipment" means any device, equipment, process or combination thereof, the operation of which would limit, capture, reduce, confine, or otherwise control regulated air pollutants or convert for the purposes of control any regulated air pollutant to another form, another chemical or another physical state. This includes, but is not limited to, sulfur recovery units, acid plants, baghouses, precipitators, scrubbers, cyclones, water sprays, enclosures, catalytic converters, and steam or water injection.

Section 15

Alternative Operating Scenarios

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

Alternative Operating Scenarios: Provide all information required by the department to define alternative operating scenarios. This includes process, material and product changes; facility emissions information; air pollution control equipment requirements; any applicable requirements; monitoring, recordkeeping, and reporting requirements; and compliance certification requirements. Please ensure applicable Tables in this application are clearly marked to show alternative operating scenario.

Construction Scenarios: When a permit is modified authorizing new construction to an existing facility, NMED includes a condition to clearly address which permit condition(s) (from the previous permit and the new permit) govern during the interval between the date of issuance of the modification permit and the completion of construction of the modification(s). There are many possible variables that need to be addressed such as: Is simultaneous operation of the old and new units permitted and, if so for example, for how long and under what restraints? In general, these types of requirements will be addressed in Section A100 of the permit, but additional requirements may be added elsewhere. Look in A100 of our NSR and/or TV permit template for sample language dealing with these requirements. Find these permit templates at: https://www.env.nm.gov/aqb/permit/aqb_pol.html. Compliance with standards must be maintained during construction, which should not usually be a problem unless simultaneous operation of old and new equipment is requested.

In this section, under the bolded title "Construction Scenarios", specify any information necessary to write these conditions, such as: conservative-realistic estimated time for completion of construction of the various units, whether simultaneous operation of old and new units is being requested (and, if so, modeled), whether the old units will be removed or decommissioned, any PSD ramifications, any temporary limits requested during phased construction, whether any increase in emissions is being requested as SSM emissions or will instead be handled as a separate Construction Scenario (with corresponding emission limits and conditions, etc.

EPE does not have any alternative operating scenarios for this installation. All emission sources included in this Title V Operation Permit will operate with the use of natural gas only.

Section 16

Air Dispersion Modeling

1) Minor Source Construction (20.2.72 NMAC) and Prevention of Significant Deterioration (PSD) (20.2.74 NMAC) ambient impact analysis (modeling): Provide an ambient impact analysis as required at 20.2.72.203.A(4) and/or 20.2.74.303 NMAC and as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines found on the Planning Section's modeling website. If air dispersion modeling has been waived for one or more pollutants, attach the AQB Modeling Section modeling waiver approval documentation.
2) SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions during routine or predictable startup, shutdown, or maintenance (SSM) using realistic worst case scenarios following guidance from the Air Quality Bureau's dispersion modeling section. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.
3) Title V (20.2.70 NMAC) ambient impact analysis: Title V applications must specify the construction permit and/or Title V Permit number(s) for which air quality dispersion modeling was last approved. Facilities that have only a Title V permit, such as landfills and air curtain incinerators, are subject to the same modeling required for preconstruction permits required by 20.2.72 and 20.2.74 NMAC.

What is the purpose of this application?	Enter an X for each purpose that applies
New PSD major source or PSD major modification (20.2.74 NMAC). See #1 above.	
New Minor Source or significant permit revision under 20.2.72 NMAC (20.2.72.219.D NMAC). See #1 above. **Note:** Neither modeling nor a modeling waiver is required for VOC emissions.	
Reporting existing pollutants that were not previously reported.	
Reporting existing pollutants where the ambient impact is being addressed for the first time.	
Title V application (new, renewal, significant, or minor modification. 20.2.70 NMAC). See #3 above.	X
Relocation (20.2.72.202.B.4 or 72.202.D.3.c NMAC)	
Minor Source Technical Permit Revision 20.2.72.219.B.1.d.vi NMAC for like-kind unit replacements.	
Other: i.e. SSM modeling. See #2 above.	
This application does not require modeling since this is a No Permit Required (NPR) application.	
This application does not require modeling since this is a Notice of Intent (NOI) application (20.2.73 NMAC).	
This application does not require modeling according to 20.2.70.7.E(11), 20.2.72.203.A(4), 20.2.74.303, 20.2.79.109.D NMAC and in accordance with the Air Quality Bureau's Modeling Guidelines.	

Check each box that applies:

☐ See attached, approved modeling **waiver for all** pollutants from the facility.
☐ See attached, approved modeling **waiver for some** pollutants from the facility.
☐ Attached in Universal Application Form 4 (UA4) is a **modeling report for all** pollutants from the facility.
☐ Attached in UA4 is a **modeling report for some** pollutants from the facility.
☐ No modeling is required.

Section 17

Compliance Test History

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

To show compliance with existing NSR permits conditions, you must submit a compliance test history. The table below provides an example.

The following table (Table 17-1) shows the compliance test history for the facility.

Table 17-1 Compliance Test History Table

Unit No.	Test Description	Test Date
GT-9	Initial CEMS Certification & NOx, CO Initial Compliance Test	May 2013
EPN -3	PM Stack Test as required by NSR Permit 1554-M1	June 2013
EPN-4	PM Stack Test as required by NSR Permit 1554-M1	June 2013
GT-9	PM Stack Test as required by NSR Permit 1554-M1	June 2013
EPN-3	RATA Test as required by Title V Permit P127-R3	9/20/2013
EPN-4	RATA Test as required by Title V Permit P127-R3	9/20/2013
EPN-1	RATA Test as required by Title V Permit P127-R3	9/19/2013
GT-9	RATA Test as required by Title V Permit P127-R3	9/23/2013
EPN-3	RATA Test as required by Title V Permit P127-R3	8/24/2014
EPN-4	RATA Test as required by Title V Permit P127-R3	8/25/2014
EPN-1	RATA Test as required by Title V Permit P127-R3	8/26/2014
GT-9	RATA Test as required by Title V Permit P127-R3	8/27/2014
EPN-3	RATA Test as required by Title V Permit P127-R3	9/9/2015
EPN-4	RATA Test as required by Title V Permit P127-R3	9/10/2015
EPN-1	RATA Test as required by Title V Permit P127-R3	9/10/2015
GT-9	RATA Test as required by Title V Permit P127-R3	9/11/2015
EPN-3	RATA Test as required by Title V Permit P127-R3	9/16/2016
EPN-4	RATA Test as required by Title V Permit P127-R3	9/17/2016
EPN-1	RATA Test as required by Title V Permit P127-R3	9/17/2016
GT-9	RATA Test as required by Title V Permit P127-R3	10/11/2016
EPN-3	RATA Test as required by Title V Permit P127-R3	9/15/2017
EPN-4	RATA Test as required by Title V Permit P127-R3	9/16/2017
EPN-1	RATA Test as required by Title V Permit P127-R3	9/16/2017
GT-9	RATA Test as required by Title V Permit P127-R3	9/21/2017
EPN-3	RATA Test as required by Title V Permit P127-R3	10/30/2018
EPN-4	RATA Test as required by Title V Permit P127-R3	9/18/2018
EPN-1	RATA Test as required by Title V Permit P127-R3	9/18/2018
GT-9	RATA Test as required by Title V Permit P127-R3	9/17/2018
EPN-4	RATA Test as required by Title V Permit P127-R3	9/18/2019
EPN-1	RATA Test as required by Title V Permit P127-R3	9/18/2019
GT-9	RATA Test as required by Title V Permit P127-R3	9/19/2019
EPN-4	RATA Test as required by Title V Permit P127-R3	8/27/2020
EPN-1	RATA Test as required by Title V Permit P127-R3	8/27/2020
GT-9	RATA Test as required by Title V Permit P127-R3	8/28/2020

Section 19

Requirements for Title V Program

Do not print this section unless this is a Title V application.

Who Must Use this Attachment:

* Any major source as defined in 20.2.70 NMAC.
* Any source, including an area source, subject to a standard or other requirement promulgated under Section 111 - Standards of Performance for New Stationary Sources, or Section 112 Hazardous Air Pollutants, of the 1990 federal Clean Air Act ("federal Act"). Non-major sources subject to Sections 111 or 112 of the federal Act are exempt from the obligation to obtain an 20.2.70 NMAC operating permit until such time that the EPA Administrator completes rulemakings that require such sources to obtain operating permits. In addition, sources that would be required to obtain an operating permit solely because they are subject to regulations or requirements under Section 112(r) of the federal Act are exempt from the requirement to obtain an Operating Permit.
* Any Acid Rain source as defined under title IV of the federal Act. The Acid Rain program has additional forms. See http://www.env.nm.gov/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are encouraged to submit both applications simultaneously.
* Any source in a source category designated by the EPA Administrator ("Administrator"), in whole or in part, by regulation, after notice and comment.

This is a Title V renewal, thus this section applies to this permit effort.

19.1 - 40 CFR 64, Compliance Assurance Monitoring (CAM) (20.2.70.300.D.10.e NMAC)

Any source subject to 40CFR, Part 64 (Compliance Assurance Monitoring) must submit all the information required by section 64.7 with the operating permit application. The applicant must prepare a separate section of the application package for this purpose; if the information is already listed elsewhere in the application package, make reference to that location. Facilities not subject to Part 64 are invited to submit periodic monitoring protocols with the application to help the AQB to comply with 20.2.70 NMAC. Sources subject to 40 CFR Part 64, must submit a statement indicating your source's compliance status with any enhanced monitoring and compliance certification requirements of the federal Act.

This facility is not subject to comply with 40 CFR 64 Compliance Assurance Monitoring (CAM)

19.2 - Compliance Status (20.2.70.300.D.10.a & 10.b NMAC)

Describe the facility's compliance status with each applicable requirement at the time this permit application is submitted. This statement should include descriptions of or references to all methods used for determining compliance. This statement should include descriptions of monitoring, recordkeeping and reporting requirements and test methods used to determine compliance with all applicable requirements. Refer to Section 2, Tables 2-N and 2-O of the Application Form as necessary. (20.2.70.300.D.11 NMAC) For facilities with existing Title V permits, refer to most recent Compliance Certification for existing requirements. Address new requirements such as CAM, here, including steps being taken to achieve compliance.

El Paso Electric Company (EPE) believes that the Rio Grande Generating Station is in compliance with each applicable requirement identified in Section 13. In the event that EPE should discover new information affecting the compliance status of the facility, EPE will make appropriate notifications and/or take corrective actions.

19.3 - Continued Compliance (20.2.70.300.D.10.c NMAC)

Provide a statement that your facility will continue to be in compliance with requirements for which it is in compliance at the time of permit application. This statement must also include a commitment to comply with other applicable requirements as they come into effect during the permit term. This compliance must occur in a timely manner or be consistent with such schedule expressly required by the applicable requirement.

The facility will continue to be in compliance with requirements for which it is in compliance at the time of this permit application and will comply with other applicable requirements as they come into effect during the permit term.

19.4 - Schedule for Submission of Compliance (20.2.70.300.D.10.d NMAC)

You must provide a proposed schedule for submission to the department of compliance certifications during the permit term. This certification must be submitted annually unless the applicable requirement or the department specifies a more frequent period. A sample form for these certifications will be attached to the permit.

Compliance certification will be submitted annually, as required by Title V Permit.

19.5 - Stratospheric Ozone and Climate Protection

In addition to completing the four (4) questions below, you must submit a statement indicating your source's compliance status with requirements of Title VI, Section 608 (National Recycling and Emissions Reduction Program) and Section 609 (Servicing of Motor Vehicle Air Conditioners).

---

1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ☒ **Yes** ☐ **No**

2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ☐ **Yes** ☒ **No**

   (If the answer is yes, describe the type of equipment and how many units are at the facility.)

3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ☐ **Yes** ☒**No**

4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40 CFR Part 82, Subpart A through G.)

No 40 CFR 82 requirements apply to this facility.

19.6 - Compliance Plan and Schedule

Applications for sources, which are not in compliance with all applicable requirements at the time the permit application is submitted to the department, must include a proposed compliance plan as part of the permit application package. This plan shall include the information requested below:

A. Description of Compliance Status: (20.2.70.300.D.11.a NMAC)
A narrative description of your facility's compliance status with respect to all applicable requirements (as defined in 20.2.70 NMAC) at the time this permit application is submitted to the department.

B. Compliance plan: (20.2.70.300.D.11.B NMAC)
A narrative description of the means by which your facility will achieve compliance with applicable requirements with which it is not in compliance at the time you submit your permit application package.

C. Compliance schedule: (20.2.70.300D.11.c NMAC)
A schedule of remedial measures that you plan to take, including an enforceable sequence of actions with milestones, which will lead to compliance with all applicable requirements for your source. This schedule of compliance must be at least as stringent as that contained in any consent decree or administrative order to which your source is subject. The obligations of any consent decree or administrative order are not in any way diminished by the schedule of compliance.

D. Schedule of Certified Progress Reports: (20.2.70.300.D.11.d NMAC)
A proposed schedule for submission to the department of certified progress reports must also be included in the compliance schedule. The proposed schedule must call for these reports to be submitted at least every six (6) months.

E. Acid Rain Sources: (20.2.70.300.D.11.e NMAC)
If your source is an acid rain source as defined by EPA, the following applies to you. For the portion of your acid rain source subject to the acid rain provisions of title IV of the federal Act, the compliance plan must also include any additional requirements under the acid rain provisions of title IV of the federal Act. Some requirements of title IV regarding the schedule and methods the source will use to achieve compliance with the acid rain emissions limitations may supersede the requirements of title V and 20.2.70 NMAC. You will need to consult with the Air Quality Bureau permitting staff concerning how to properly meet this requirement.

NOTE: The Acid Rain program has additional forms. See http://www.env.nm.gov/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are **encouraged** to submit both applications **simultaneously**.

No compliance plan required since El Paso Electric Company (EPE) believes that the Rio Grande Generating Station is in compliance with each applicable requirement, as identified in Section 13.

19.7 - 112(r) Risk Management Plan (RMP)

Any major sources subject to section 112(r) of the Clean Air Act must list all substances that cause the source to be subject to section 112(r) in the application. The permittee must state when the RMP was submitted to and approved by EPA.

Not applicable to this facility

19.8 - Distance to Other States, Bernalillo, Indian Tribes and Pueblos

Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B NMAC)?

(If the answer is yes, state which apply and provide the distances.)

Yes, El Paso, Texas (Facility is adjacent to state line); Mexico Border (approximately1-2 miles). No Indian Tribes nor Pueblos within the required radius.

19.9 - Responsible Official

Provide the Responsible Official as defined in 20.2.70.7.AD NMAC: Steven T. Buraczyk

Section 20

Other Relevant Information

<u>Other relevant information</u>. Use this attachment to clarify any part in the application that you think needs explaining. Reference the section, table, column, and/or field. Include any additional text, tables, calculations or clarifying information.

Additionally, the applicant may propose specific permit language for AQB consideration. In the case of a revision to an existing permit, the applicant should provide the old language and the new language in track changes format to highlight the proposed changes. If proposing language for a new facility or language for a new unit, submit the proposed operating condition(s), along with the associated monitoring, recordkeeping, and reporting conditions. In either case, please limit the proposed language to the affected portion of the permit.

Due to an agency error in both the permit expiration date as well as the renewal application due date on the cover page of the most recent Title V permit renewal issued by NMED AQB this application is being submitted within 1 year of the current permit's expiration date as per agency instructions. The renewal must be completed before the current permit expires to avoid the loss of the permit shield. No other relevant information is being submitted as part of this application.

Section 22: Certification

Company Name: El Paso Electric

I, Steve Buraczyk, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 9th day of June, 2021, upon my oath or affirmation, before a notary of the State of

Texas.

*Signature

Date 6/9/21

Steve Buraczyk
Printed Name

Sr Vice President
Title

Scribed and sworn before me on this 9 day of June, 2021.

My authorization as a notary of the State of Texas expires on the

9 day of December, 2021.

Notary's Signature

6-9-2021
Date

Valerie J Pugh
Notary's Printed Name

NOTARY PUBLIC STATE OF TEXAS
VALERIE J. PUGH
My Notary ID # 10712464
Expires December 9, 2024

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.