CHASE
POWER DEVELOPMENT, LLC

11011 Richmond, Suite 350
Houston Texas 77042

t. 713-351-6700
f. 713-351-6750

October 28, 2011

Mr. Jeff Robinson
Chief, Air Permits Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Application for a Prevention of Significant Deterioration Air Quality Permit for Greenhouse Gas Emissions
Las Brisas Energy Center, LLC
Corpus Christi, Nueces County, Texas

Dear Mr. Robinson:

Chase Power Development LLC., on behalf of Las Brisas Energy Center, LLC (LBEC) is hereby submitting this application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of a new circulating fluidized bed steam electric generation facility on the Joe Fulton Corridor bordering the west side of the Port of Corpus Christi Bulk Terminal in Corpus Christi, Texas.

The Plant is authorized for emissions of all non-greenhouse gas air contaminants under Texas Commission on Environmental Quality (TCEQ) Permit No. 85013/PSD-TX-1138/HAP-48. General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled *"PSD and Title V Permitting Guidance For Greenhouse Gases", dated November 2010 and March 2011,* was utilized as a guide for preparation of the attached application.

LBEC is committed to working closely with EPA Region 6 to get the application review completed as expeditiously as possible. LBEC will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any questions that your team may have after initially reading our application.

Should you have any questions regarding this application, please contact me either by e-mail at johnupchurch@chase-power.com or by telephone at (713) 351-6701.

Sincerely,

John Upchurch
Managing Partner
Chase Power Development LLC.

Enclosure

cc: Mr. Mike Wilson, P.E., Director, Air Permits Division, TCEQ

Mr. Larry Moon, P.E., Zephyr Environmental Corporation

Prevention of Significant Deterioration Greenhouse Gas Permit Application for a New Circulating Fluidized Bed Steam Electric Generating Facility
Las Brisas Energy Center, LLC
Corpus Christi, Nueces County, Texas

Submitted to:

Environmental Protection Agency
Region VI
Multimedia Planning and Permitting Division
Fountain Place 12th Floor, Suite 1200
1445 Ross Avenue
Dallas, Texas 75202-2733

Submitted by:

Las Brisas Energy Center, LLC
Corpus Christi, Texas 78409

Prepared by:

Zephyr Environmental Corporation
2600 Via Fortuna, Suite 450
Austin, Texas 78746

October, 2011

10-28-2011

Zephyr Environmental Corporation
STATE OF TEXAS
LARRY A. MOON
69515
LICENSED
PROFESSIONAL ENGINEER
F-102

zephyr

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APPENDICES

1.0 INTRODUCTION

Las Brisas Energy Center, LLC (Las Brisas) proposes to construct and operate a new circulating fluidized bed (CFB) steam electric generation facility, known as the Las Brisas Energy Center (LBEC), on the Joe Fulton Corridor bordering the west side of the Port of Corpus Christi Bulk Terminal in Corpus Christi, Texas. The facility, with an approximate nominal capacity of generating 1,200 megawatts electricity (MWe), will provide electricity to the existing regional grid.

More than three years ago, Las Brisas began the Prevention of Significant Deterioration (PSD) air permitting process in its effort to build the LBEC to be fueled by petroleum coke, a fuel that is produced in significant quantity in the nearby Corpus Christi refineries and, generally, in the Gulf Coast region. Las Brisas submitted an air permit application to the Texas Commission on Environmental Quality (TCEQ) on May 19, 2008, which the TCEQ Executive Director (ED) declared administratively complete on May 23, 2008. Thereafter, the ED commenced technical review of the application and, on January 7, 2009, after completing that review, made the preliminary decision to issue the permit. Having preliminarily decided to issue the permit, the ED also issued a draft permit for public notice and comment at that time. On June 11, 2009, following the close of the public comment period, the ED issued his response to public comments along with a revised draft permit.

In addition to affording the public the opportunity to provide comments regarding the permit application and draft permit, the TCEQ permitting process also affords interested parties the opportunity to participate in a trial-like contested case hearing process before the State Office of Administrative Hearings (SOAH). Such a hearing, including a remand proceeding,[1] regarding the LBEC PSD air permit spanned the time from February 2009 to November 2010 and, on December 1, 2010, SOAH issued a revised Proposal For Decision. The TCEQ Commissioners considered the revised PFD on January 26, 2011, and voted to issue the LBEC PSD air permit. Motions for rehearing were overruled by operation of law on April 12, 2011, and, subsequently, Las Brisas received a signed permit dated April 18, 2011. The TCEQ permit does not address greenhouse gas emissions but the LBEC is authorized for emissions of all non-greenhouse gas air contaminants under TCEQ Permit No. 85013/PSD-TX-1138/HAP-48 (copy provided in Appendix A).

According to the U.S. Environmental Protection Agency (EPA), PSD permits issued on or after January 2, 2011 must address greenhouse gas emissions unless the permitted source's greenhouse gas emissions fall below the levels set forth in EPA's Greenhouse Gas Tailoring Rule. *See* 75 Fed. Reg. 31,514, 31,523 (June 3, 2010). Because LBEC's greenhouse gas emissions will not be below those levels, whether Las Brisas must obtain a separate greenhouse gas PSD permit for LBEC pursuant to the Tailoring Rule turns on whether the PSD

[1] The remand proceeding was delayed approximately six weeks due to a witness for a party opposing issuance of the permit being injured in an automobile accident.

permit LBEC applied for almost three years ago and has received from TCEQ was "issued" prior to January 2, 2011.

On April 2, 2010, almost two years after Las Brisas applied to TCEQ for the LBEC air permit, EPA explained that it saw no need to grandfather then-pending permit applications from greenhouse gas requirements because such permit applications "should in most cases be issued prior to January 2, 2011." 75 Fed. Reg. 17,004, 17,021 (Apr. 2, 2010). After finalizing its Tailoring Rule, EPA issued guidance explaining, among other things, PSD applicability under the rule. *See* EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Mar. 2011), available at http://www.epa.gov/nsr/ghgpermitting.html (last visited Apr. 24, 2011) (hereinafter "EPA's Greenhouse Gas Permitting Guidance"). That guidance provides further insight into the basis of EPA's expectation that the majority of PSD permits pending in April 2010 would be issued before January 2011, or within a period of just nine months. Specifically, EPA explains that "the date a permit is issued is not necessarily the same as the date the permit becomes effective or final agency action for purposes of judicial review" but instead is "when a permitting authority issues a PSD permit after public comment on a draft permit or preliminary determination to issue a PSD permit." *Id*. at 3 n.6.

EPA's Greenhouse Gas Permitting Guidance further suggests that a "similar approach" to permit issuance should be used in states like Texas with "analogous administrative procedures." *Id.* Applying a "similar approach" to the LBEC PSD permit, as EPA suggests, Las Brisas maintains that the LBEC PSD permit was "issued" for purposes of EPA's Tailoring Rule on June 11, 2009 when, after making the preliminary decision to issue the permit and receiving public comment, the ED issued his response to public comment and a revised draft permit. Nonetheless, EPA has indicated that Las Brisas must obtain a second PSD permit to authorize the LBEC greenhouse gas emissions because, in its view, the PSD permit Las Brisas received from TCEQ was issued after January 2, 2011.

Furthermore, on December 13, 2010, EPA issued a SIP Call, requesting the submission of revised State Implementation Plans (SIPs) from thirteen states, including Texas, as part of its new effort to regulate greenhouse gases. *See* 75 Fed. Reg. 77,698, 77,705 (Dec. 13, 2010). Texas was told that it had to submit a revised PSD SIP by December 1, 2011, or else EPA would issue its own PSD Federal Implementation Plan (FIP) at that time. *Id*. at 77,716; *see also* Clean Air Act § 110(c)(1)(A), 42 U.S.C. 7410(c)(1)(A) (describing EPA's power to issue a FIP). Just over two weeks later, though, EPA, without prior notice, made an abrupt change in course, "correcting" its 1992 approval of Texas's PSD SIP and issuing an interim final rule instantly imposing a FIP on Texas. *See* 75 Fed. Reg. 82,430 (Dec. 30, 2010) (interim rule); *see also* 75 Fed. Reg. 82,365 (Dec. 30, 2010) (proposed rule).

Under the interim rule, EPA purportedly assumed the role of granting PSD permits for greenhouse gas-emitting sources in Texas, including sources issued non-greenhouse gas PSD permits by TCEQ on or after January 2, 2011. 75 Fed. Reg. 82,365, 82,365. In taking this action, EPA did not provide notice and comment opportunity to the public, pointing to the "good cause" exception in the Administrative Procedure Act as a justification.[2] *Id.* at 82,434 (citing APA § 553(b)(3)(B)). EPA also said that it would seek notice and comment on a final rule to replace the interim one later in the year. *Id.* And on May 3, 2011, after the signed LBEC TCEQ PSD permit was received by Las Brisas, EPA issued the final rule in apparent accordance with the APA strictures—*i.e.*, without invoking an emergency "good cause" exception and after a period of notice and comment. *See* 76 Fed. Reg. 25,178, 25,179 (May 3, 2011).

At present, Las Brisas' parent, Chase Power Development, LLC, is challenging both the interim and final rules in the United States Court of Appeals for the District of Columbia Circuit and that litigation will continue during the pendency of this permit application. Despite having a signed PSD permit, Las Brisas remains practically unable to build Las Brisas. Due to EPA's December 30, 2010 issuance of the interim rule partially disapproving Texas's PSD SIP and imposing a FIP on Texas. If Petitioner's permit is considered issued after January 2, 2011, as EPA maintains, the permit was issued under the fully approved Texas PSD SIP and, as a result, unquestionably constituted full authority for Petitioner to build Las Brisas. In other words, if not for the interim rule, Texas would not have been divested of its authority to issue PSD permits, and Las Brisas would have clear authority to build LBEC without EPA issuing a supplemental greenhouse gas (GHG) PSD permit.

With today's application and without waiving any arguments as to EPA's lack of authority to require a supplemental GHG PSD permit, LBEC is applying to the EPAPSD approval of GHG emissions. Included in this application are a project scope description, GHG emissions calculations, GHG netting analysis, and a GHG Best Available Control Technology (BACT) analysis.

[2] EPA claims that the use of the "good cause" exception was justified because "[u]nless and until EPA promulgates this [interim final] rule, Texas sources will not have available a permitting authority to process their PSD permit applications and as a result, may face delays in construction and modification." 75 Fed. Reg. at 82,434. However, EPA's presumption is incorrect because, if not for EPA's own action partially disapproving the Texas PSD SIP, that SIP would have continued to serve as a valid and effective mechanism for TCEQ to continue processing PSD permit applications for sources in Texas until at least the December 1, 2011 deadline for submitting a revised SIP. *See United States v. Cinergy Corp.*, 623 F.3d 455, 458 (7th Cir. 2010) (Posner, J.).

FORM PI-1
GENERAL APPLICATION

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Las Brisas Energy Center, LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name (☑ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): John Upchurch		
Title: Managing Partner		
Mailing Address: 11011 Richmond Avenue, Suite 350		
City: Houston	State: TX	ZIP Code: 77042
Telephone No.: 713-351-6701	Fax No.: 713-351-6751	E-mail Address: johnupchurch@chase-power.com
C. Technical Contact Name (☑ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): John Upchurch		
Title: Managing Partner		
Company Name: Las Brisas Energy Center, LLC		
Mailing Address: 11011 Richmond Avenue, Suite 350		
City: Houston	State: TX	ZIP Code: 77042
Telephone No.: 713-351-6701	Fax No.:	E-mail Address: johnupchurch@chase-power.c
D. Site Name: Las Brisas Energy Center, LLC		
E. Area Name/Type of Facility: Las Brisas Energy Center, LLC		☑ Permanent ☐ Portable
F. Principal Company Product or Business: Electric Power Generation		
Principal Standard Industrial Classification Code (SIC): 4939		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: November 2012		
Projected Start of Operation Date: January 2017		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: On the Joe Fulton Corridor bordering the west side of the Port of Corpus Christi Bulk Terminal		
6509 Joe Fulton Corridor		
City/Town: Corpus Christi	County: Nueces	ZIP Code: 78402
Latitude (nearest second): 27° 49' 18"	Longitude (nearest second): 97° 28' 38"	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I. **Applicant Information (continued)**		
I. Account Identification Number (leave blank if new site or facility): NE-A012-L		
J. Core Data Form.		
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).		☐ YES ☑ NO
K. Customer Reference Number (CN): CN603358771		
L. Regulated Entity Number (RN): RN105520779		
II. **General Information**		
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.		☐ YES ☑ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.		☐ YES ☑ NO
C. Number of New Jobs: 70-85		
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:		
Senator: Senator Juan "Chuy" Hinojosa	District No.: 20	
Representative: Representative Connie Scott	District No.: 34	
III. **Type of Permit Action Requested**		
A. Mark the appropriate box indicating what type of action is requested. Initial ☑ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐		
B. Permit Number (if existing): 85013, PSD-TX-1138, HAP-48		
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☑ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☑ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________________		
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).		☐ YES ☑ NO

III. Type of Permit Action Requested (continued)			
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.			☐ YES ☑ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.			☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?			☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.			
List:			
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.			☑ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)			
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).			☑ YES ☐ NO ☐ To be determined
Associated Permit No (s.):			
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☑ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐			

III.	**Type of Permit Action Requested (continued)**	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application: submitted or under APD review ☐	
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☑ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☑ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☑ NO
D.	Is this a state permit amendment application? If Yes, complete IV.D.1. – IV.D.3.	☐ YES ☑ NO
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
E.	List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*):	
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NO_x):		
Particulate Matter (PM):		
PM $_{10}$ microns or less (PM_{10}):		
PM $_{2.5}$ microns or less ($PM_{2.5}$):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above:		

V. **Public Notice Information (complete if applicable)**			
A. Public Notice Contact Name: N/A			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
Telephone No.:	Fax No.:	E-mail Address:	
B. Name of the Public Place:			
Physical Address (No P.O. Boxes):			
City:	County:	ZIP Code:	
Telephone No.:	Fax No.:	E-mail Address:	
The public place has granted authorization to place the application for public viewing and copying.			☐ YES ☐ NO
The public place has internet access available for the public.			☐ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
Telephone No.:	Fax No.:	E-mail Address:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s) (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
Telephone No.:	Fax No.:	E-mail Address:	

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the chief executives of the city and county, State, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.		
Chief Executive:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
Name of the State or Federal Land Manager (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:
Name of the Indian Governing Body (☐ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
Telephone No.:	Fax No.:	E-mail Address:

D. Bilingual Notice	
Is a bilingual program **required** by the Texas Education Code in the School District?	☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program?	
VI. Small Business Classification (Required)	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☑ YES ☐ NO
B. Is the site a major stationary source for federal air quality permitting?	☑ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☑ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☑ NO

VII.	**Technical Information**			
A.	The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)			
1.	Current Area Map ☑			
2.	Plot Plan ☑			
3.	Existing Authorizations ☐			
4.	Process Flow Diagram ☑			
5.	Process Description ☑			
6.	Maximum Emissions Data and Calculations ☑			
7.	Air Permit Application Tables ☐			
a.	Table 1(a) (Form 10153) entitled, Emission Point Summary ☑			
b.	Table 2 (Form 10155) entitled, Material Balance ☑			
c.	Other equipment, process or control device tables ☑			
B.	Are any schools located within 3,000 feet of this facility?			☐ YES ☑ NO
C.	Maximum Operating Schedule:			
Hours: 24	Day(s): 7	Week(s): 52	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☐ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☐ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☑ NO
F.	Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☑ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☐ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☐ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☐ YES ☐ NO

VIII.	**State Regulatory Requirements (continued)** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*	
D.	**Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?**	☐ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?	☑ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	☐ YES ☑ NO
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES ☑ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☑ NO
E.	Does prevention of significant deterioration permitting requirements apply to this application?	☑ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☑ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☑ NO
X.	**Professional Engineer (P.E.) Seal**	
	Is the estimated capital cost of the project greater than $2 million dollars?	☑ YES ☐ NO
	If *Yes*, submit the application under the seal of a Texas licensed P.E.	

XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ N/A
Company name on check:	Paid online?: ☐ YES ☐ NO
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☐ N/A

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

XII. Delinquent Fees And Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: JOHN UPCHURCH
Signature: _______ *Original Signature Required*
Date: 10 · 28 · 2011

2.0 PROJECT SCOPE

2.1 PLANT DESIGN CONSIDERATIONS

The proposed facility will consist of four 300-MWe (nominal output) CFB boilers that are designed to use petroleum coke as fuel. The steam produced from the boilers will be routed to two single turbine generator sets. The power generated will be sold to regional load serving entities for resale via the local electricity transmission and distribution grid.

Petroleum coke, the exclusive fuel permitted for use by the LBEC, is a carbonaceous solid derived from oil refinery coker units or other cracking processes. The use of petroleum coke is fundamental to the Las Brisas' business plan. Specifically, the location for the project has been selected because of its proximity to petroleum coke producers in the region. These producers are also potential significant power customers, and the ability for LBEC to off-take petroleum coke in exchange for power purchases is fundamental to the project. Locating Las Brisas close to the source of petroleum coke provides for lower costs associated with transportation of the petroleum coke. Also, because present users of the petroleum coke are more remote from the producing refineries, there will necessarily be a reduction of the GHG emissions associated with present transportation of the fuel to current users. A process flow diagram is included as Figure IX-C-1.

Las Brisas proposes to use circulating fluidized bed (CFB) technology for the power boilers. The pulverized coal-fired (PC) boiler is the technology predominantly used at existing U.S. electric utility solid fuel-firing power plants. Fluidized bed combustion is a newer technology that can be considered as an alternative to building a new PC-fired electric generating unit EGU, depending on project specific requirements. The term "fluidized" refers to the state of the bed materials (fuel and inert material) as gas passes through the bed. In a typical fluidized bend combustion (FBC) EGU, combustion occurs when fuel and a sorbent, such as limestone, are suspended through the action of primary combustion air distributed below the combustor floor. The gas cushion between the solids allows the particles to move freely, giving the bed a liquid-like characteristic (i.e., fluidized). FBC can occur in either atmospheric or pressurized boilers. Two fluidized bed designs can be used for atmospheric and pressurized FBC boilers: a bubbling fluidized bed or a CFB.

The primary reason for selection of CFB technology for the Las Brisas project is that it has the ability to more efficiently burn 100% petroleum coke. Even though the combustion temperature of a CFB boiler is lower than a PC boiler, the circulation of hot particles provides efficient heat transfer to the furnace walls and allows longer residence time for carbon combustion and limestone reaction. Thus, a CFB can more efficiently burn any type and rank of solid fossil fuel, and performs better than PC technology with low volatility fuels, such as petroleum coke (lower volatility presents flame stability issues in PC boilers).

CFB boilers, like PC boilers, can be used with either subcritical or supercritical steam cycles. LBEC selected a subcritical design for its CFB units because it is a more mature design that has demonstrated a known reliability and operational cost history. When Las Brisas submitted its State and PSD air permit application in May 2008, no supercritical CFB units were in operation and, even now, only one is operating worldwide a 460 MWe unit at a power plant owned by the Polish utility company Południowy Koncern Energetyczny SA (PKE) in Lagisza, Poland. This plant, which burns a different fuel, bituminous coal, began operation in June 2009. Considering that only one supercritical CFB unit is in operation and only a small amount of operational data to document the reliability and operational costs of the KKE unit is available, supercritical steam technology is not a consideration for Las Brisas in the selection of boiler technology.

Additionally, it is not clear whether the supercritical steam CFB technology could reduce NOx and SO_2 emissions at required BACT levels without the addition of an SCR, which has been determined to not be technically feasible for the LBEC in the proceedings before the TCEQ. The PKE plant was permitted at the following emission limits: 200 mg/m^{3}n @ 6% O_2, dry for both NOx and SO_2.[3] This equates to 0.17 lb/MMBtu for both NOx and SO_2, utilizing the Fd Factor for Bituminous Coal of 9,780 dscf/MMBtu[4]. The PKE NOx emission limit of 0.17 lb/MMBtu is approximately 2.4 times higher than the annual average NOx limit for LBEC of 0.07 lb/MMBtu. The PKE SO_2 emission limit of 0.17 lb/MMBtu is approximately 2 times higher than the annual average SO_2 limit for LBEC of 0.086 lb/MMBtu

Pressurized Fluidized-Bed Combustion (PFBC) is another technology that has been employed in recent years. These systems typically operate at elevated pressures of 1 to 1.5 MPa (145 to 218 psia) and produce a high pressure gas stream that can drive a turbine. Similar to the atmospheric pressure CFB, as that proposed for LBEC, the fuel and sorbent (for SO_2 reduction) are introduced into the boiler together. However the combustor and cyclones are enclosed in a pressure vessel and the crushed fuel and sorbent, as well as the ash, must be fed across a pressure boundary. Combustion temperatures of the PFBC boiler are similar to that of the atmospheric (1,500 to 1,650 ^oF).

Demonstration projects ranging in size from 60 MW to 130 MW were constructed and operated in the 1990's in areas of Europe and the United States. Japanese equipment manufacturers and electric utility companies have constructed and are currently operating other PFBC facilities three areas of the country. The largest of these units is the 360MW unit in Kitakyushu, Japan operated by the Kyushu Electric Power Company. Chugoku Electric Power Company operates a 250 MW unit and Hokaido Electric Power Company operates a smaller 85 MW unit.

All of these facilities have been designed to utilize coal as the fuel source. Petroleum coke has been fired in a PFBC boiler in a test facility in Sweden. However, the PFBC technology has not been proven with petroleum coke as a fuel source for a utility scale boiler. In addition to the

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[3] *Lagisza 460 MWe Supercritical CFB Design, Start-up and Initial Operation Experience*, Foster Wheeler, Oct. 2009

[4] 40 CFR 60, Appendix A, Reference Method 19, Table 19-2.

unproven boiler technology, the gas turbine provided for the Kitakyushu facility, at 75 MW, is the largest ever built as a prototype. Given the fact that petroleum coke has not been proven in a utility scale PFBC boiler and the prototypical nature of the gas turbines, the PFBC technology is not a commercially viable alternative for LBEC.

Another potential technology for power generation using petroleum coke is an integrated gasification combined cycle (IGCC) power plant. This technology integrates a fuel conversion plant (the gasification process) with a traditional combustion turbine – steam turbine combined cycle power plant. The gasification process combines a feedstock, in this case petroleum coke, with steam in a low oxygen atmosphere at a high temperature and pressure to produce a "syngas", which is then combusted in the gas turbines to generate electricity. Heat from the gasifiers and the combustion turbine exhaust is used to create steam that is then passed through a steam turbine to generate additional electricity.

Although these two technologies have existed for many years, the integration of the two technologies, in an effort to achieve a higher efficiency, adds to the complexity of the power generation process. The syngas requires cooling and scrubbing prior to introducing it into the combustion turbine to protect the turbine and separate some of the polluting constituents. The combustion turbine also requires modification to burn the low Btu syngas (about ¼ that of natural gas) and the syngas must be mixed with nitrogen to lower the flame temperature and resultant NOx production which further reduces the Btu value of the fuel. The gasification process as well as the high temperatures, high pressures, and additional equipment result in shortened maintenance intervals of the equipment and thus the availability of the facility is reduced.

IGCC facilities have been constructed and are currently operating. Historically the availability of these generating stations has been very low in the first year of operation (ranging from less than 10% to 40%). The availability of these facilities have increased over time as the operational experiences has been extended; however there are few that have achieved an availability of 70% or greater and only one has achieved an availability of more than 80%. [**Source:** EPRI, Dr. J. Phillips, "Integrated Gasification Combined Cycles with CO_2 Capture", Stanford University Global Climate Change & Energy Project Research Symposium, June 13-16, 2005.] The Las Brisas Energy Center will have an availability of 92% or greater beginning the first year of operation.

As indicative of industry information, the most advanced IGCC development that is still being pursued is the Duke Energy, Edwardsport facility. The reported cost of this proposed 630 MW IGCC project is now $2.88 billion[5] (excluding financing costs) which is equivalent to a cost of $4,730 per kilowatt (kW) with a scheduled commercial operation date in 2012. Early cost estimates for the project were approximately $1 billion lower (at $1.985 billion) than is currently being experienced. Current costs are from an update provided by Duke Energy during the 3rd

[5] Duke Energy, *Edwardsport IGCC Plant Fact Sheet*
http://www.duke-energy.com/pdfs/IGCC-Fact-sheet-12.10.pdf (last visited 10/27/2011)

Quarter of 2011. Using the current cost information, this IGCC facility will be constructed at a 97% premium on a $/kW basis over the CFB installation planned for the Las Brisas facility.
Cost reports for other IGCC projects include an estimated cost of $2.4 billion[6] ($4,123/kW) for the Kemper IGCC project being developed by Mississippi Power, with a planned in-service date of 2014. This is a 582 MW lignite fueled IGCC in Mississippi. The construction costs for this facility is a 72% premium over the Las Brisas Project. The project has received approximately $300 million in federal funds and has set a cap on the potential project costs of $3.2 billion or roughly $5,500/kW. Similarly, the latest estimates in 2010 for the Tenaska Taylorville IGCC project in Illinois were capped at $3.5 billion[7], or $5,800/kW for this 602 MW installation. In general terms, this data indicates that there is still a significant degree of uncertainty regarding IGCC project costs. There is however, a clear indication that IGCC construction is expected to be at a significant cost premium. In a deregulated market as exists in Texas, a facility with this cost premium and reliability concerns would not be able to compete in the market.
In summary, Las Brisas has chosen to utilize subcritical CFB boiler technology for its power generation equipment for the following reasons:

- CFB boilers provide the ability to more efficiently burn the petroleum coke that is the basis for Las Brisas.
- Even though the combustion temperature of a CFB is low, the fuel residence time is higher than that of a PC, which results in high combustion efficiencies.
- Subcritical technology has been proven to be reliable and cost effective, while little operational data exist to support the use of supercritical technology.

2.2 CFB BOILERS

Las Brisas will include four 300-MWe (nominally rated) CFB boilers that will use petroleum coke as fuel. During startup, natural gas and/or propane will be used prior to firing of the petroleum coke. The first two CFB boilers (Emission Point Number (EPN) CFB-1 and CFB-2) will drive one of the single steam turbine-generator sets. The third and fourth CFB Boilers (EPN CFB-3 and CFB-4) will feed steam to a second single steam turbine-generator.

2.3 AUXILIARY BOILERS

Two nominally rated 180 MMBtu/hr auxiliary boilers (EPNs AUX-BOIL1 and AUX-BOIL2) will be utilized during start-up and shutdown activities to provide auxiliary steam which may be required to stabilize the system. The boilers will be used during the commissioning phase of the project

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[6] Mississippi Power, *Kemper IGCC Brochure*
http://www.mississippipower.com/kemper/IGCC_BROCHURE.pdf (last visited 10/27/2011)

[7] Tenaska News Release, July 13, 2009
http://www.tenaska.com/newsItem.aspx?id=62

(prior to normal operation) as well as during normal operation. Each auxiliary boiler will be limited to 2,500 hours of operation per year.

2.4 PROPANE VAPORIZERS

Two nominally rated 16-MMBtu/hr propane vaporizers (EPNs: PROP-VAP1 and PROP-VAP2) will be utilized as a source of CFB start-up fuel in the event natural gas is not available. The vaporizers may be used during the commissioning phase of the project as well as during normal operation. Each vaporizer will be limited to 2,500 hours of operation per year.

2.5 DIESEL-FIRED EMERGENCY EQUIPMENT

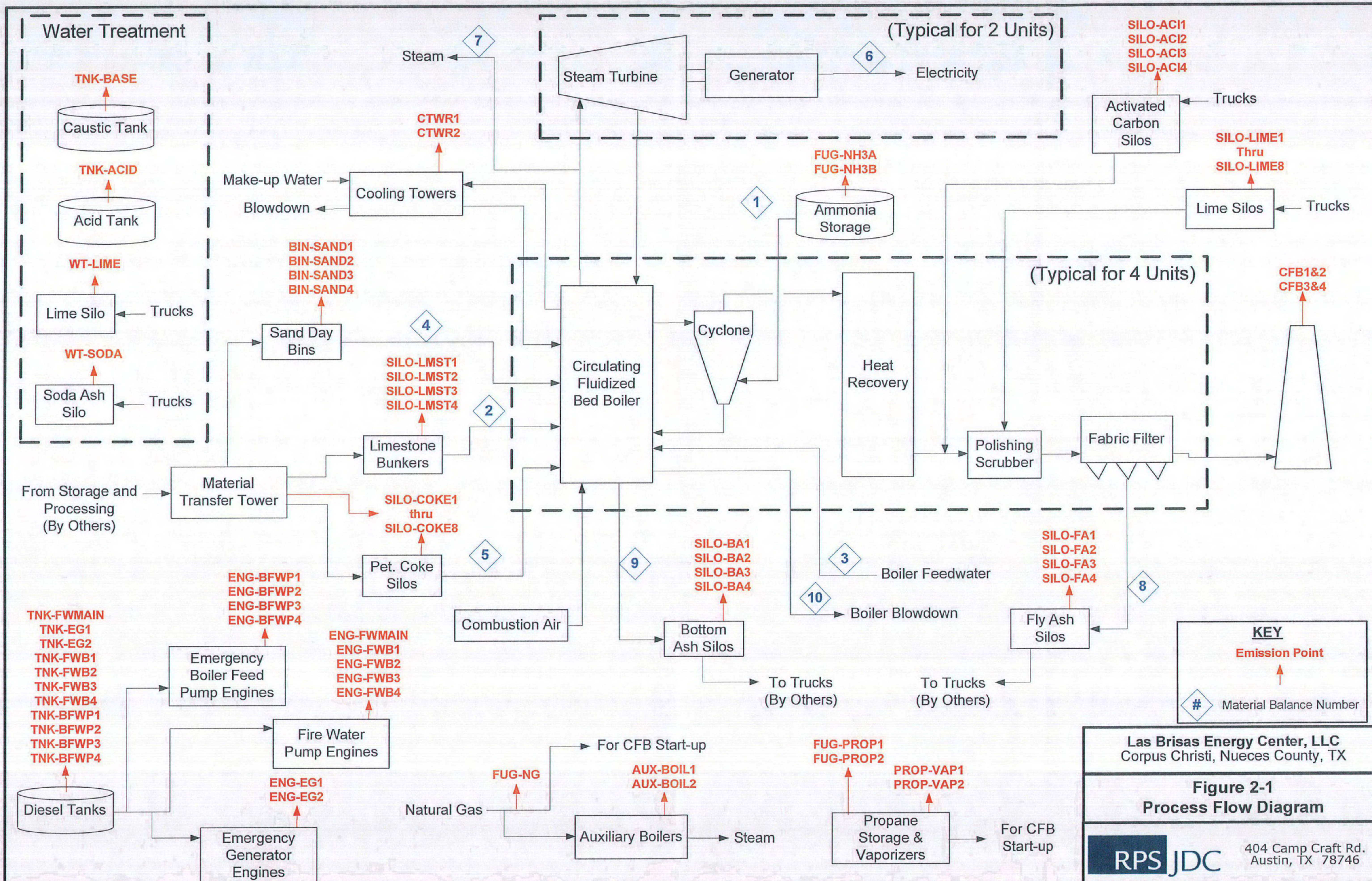
The site will be equipped with two nominally rated 1,600 kW diesel-fired emergency generators (EPNs: ENG-EG1and ENG-EG-2) to provide electricity to the facility in case of power failure. A nominally rated 360-HP diesel-fired pump (EPN: ENG-FWMAIN) will be installed at the site to provide water in the event of a fire. Four nominally rated 100-HP diesel-fired pumps (EPNs: ENG-FWB1, ENG-FWB2, ENG-FWB3, and ENG-FWB4) will be installed at the site to serve as fire water booster pumps at each of the CFB boilers. Four nominally rated 2,000-HP diesel-fired boiler feed water pumps (EPNs: ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4) will be installed at the site to serve as emergency boiler feed water pumps at each of the CFB boilers. Each emergency engine will be limited to 100 hours operation per year for purposes of maintenance checks and readiness testing. Note that the emergency engines were authorized for 500 hours operation per year in TCEQ Permit No. 85013/PSD-TX-1138/HAP-48. However, New Source Performance Standards (NSPS) Subpart IIII –Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, limits the operation of emergency internal combustion engines to 100 hours per year for the purpose of maintenance checks and readiness testing.[8]

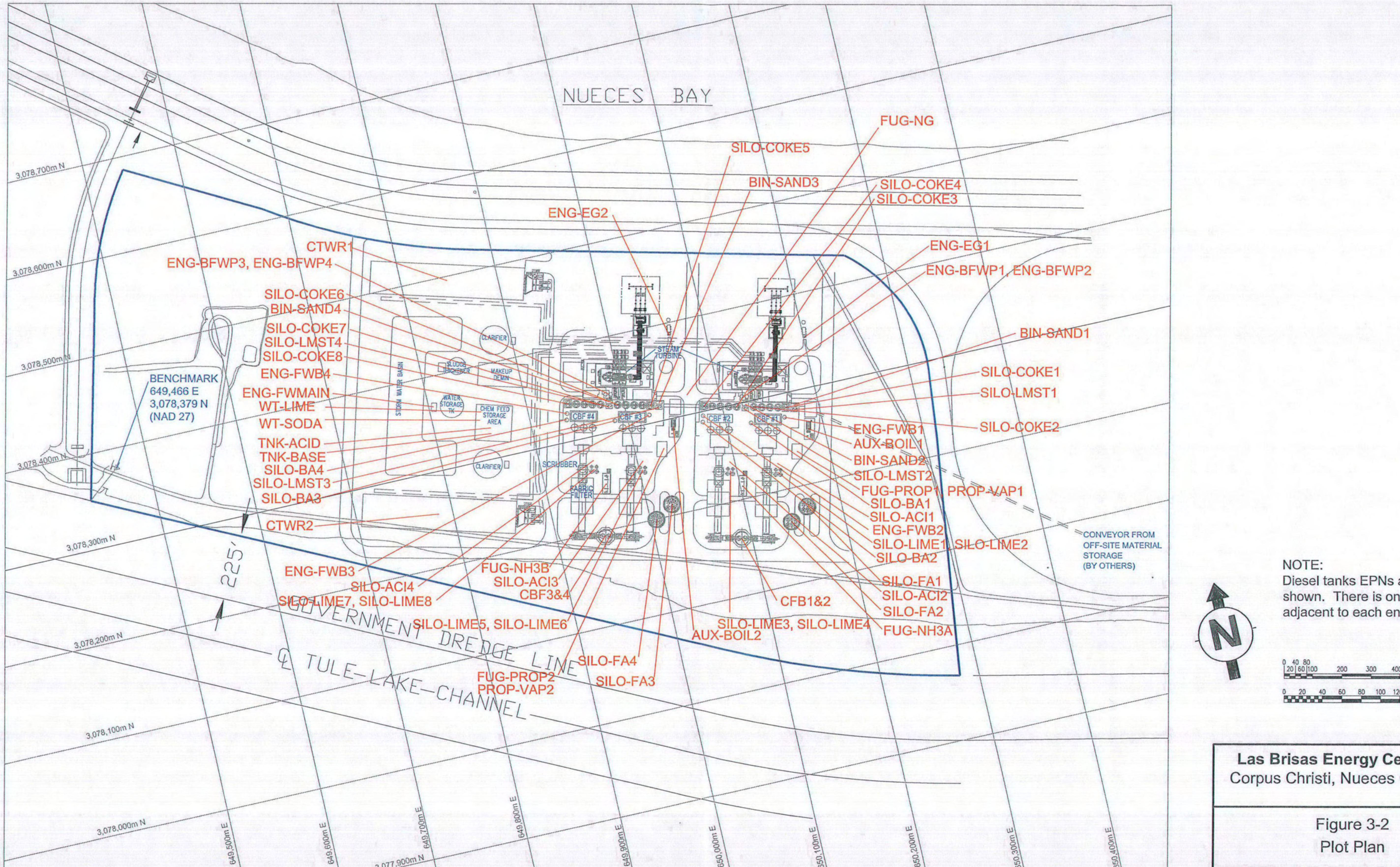
2.6 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breakers associated with the proposed CFB units will be insulated with SF_6. SF_6, a fluorinated compound that has an extremely stable molecular structure, is a colorless, odorless, non-flammable, and non-toxic synthetic gas. The unique chemical properties of SF_6 make it an efficient electrical insulator; it is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the generator circuit breakers associated with the proposed unit will be approximately 570 lb.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel to any leakage in the system and the lockout will prevent any operation of the breaker due to lack of “quenching and cooling” SF_6 gas.

[8] 40 CFR §60.4211(e)


Water Treatment
TNK-BASE
Caustic Tank
TNK-ACID
Acid Tank
WT-LIME
Lime Silo
Trucks
WT-SODA
Soda Ash Silo
Trucks
Steam
7
(Typical for 2 Units)
Steam Turbine
Generator
6
Electricity
SILO-ACI1
SILO-ACI2
SILO-ACI3
SILO-ACI4
Activated Carbon Silos
Trucks
CTWR1
CTWR2
Make-up Water
Cooling Towers
Blowdown
FUG-NH3A
FUG-NH3B
1
Ammonia Storage
SILO-LIME1
Thru
SILO-LIME8
Lime Silos
Trucks
BIN-SAND1
BIN-SAND2
BIN-SAND3
BIN-SAND4
Sand Day Bins
4
(Typical for 4 Units)
CFB1&2
CFB3&4
Circulating Fluidized Bed Boiler
Cyclone
Heat Recovery
SILO-LMST1
SILO-LMST2
SILO-LMST3
SILO-LMST4
2
Limestone Bunkers
Polishing Scrubber
Fabric Filter
From Storage and Processing (By Others)
Material Transfer Tower
SILO-COKE1
thru
SILO-COKE8
5
Pet. Coke Silos
9
SILO-BA1
SILO-BA2
SILO-BA3
SILO-BA4
3
Boiler Feedwater
SILO-FA1
SILO-FA2
SILO-FA3
SILO-FA4
8
10
Boiler Blowdown
Combustion Air
Bottom Ash Silos
Fly Ash Silos
To Trucks (By Others)
To Trucks (By Others)
KEY
Emission Point
#
Material Balance Number
TNK-FWMAIN
TNK-EG1
TNK-EG2
TNK-FWB1
TNK-FWB2
TNK-FWB3
TNK-FWB4
TNK-BFWP1
TNK-BFWP2
TNK-BFWP3
TNK-BFWP4
ENG-BFWP1
ENG-BFWP2
ENG-BFWP3
ENG-BFWP4
Emergency Boiler Feed Pump Engines
ENG-FWMAIN
ENG-FWB1
ENG-FWB2
ENG-FWB3
ENG-FWB4
Fire Water Pump Engines
Diesel Tanks
ENG-EG1
ENG-EG2
Emergency Generator Engines
FUG-NG
Natural Gas
For CFB Start-up
AUX-BOIL1
AUX-BOIL2
Auxiliary Boilers
Steam
FUG-PROP1
FUG-PROP2
PROP-VAP1
PROP-VAP2
Propane Storage & Vaporizers
For CFB Start-up
Las Brisas Energy Center, LLC
Corpus Christi, Nueces County, TX
Figure 2-1
Process Flow Diagram
RPS JDC
404 Camp Craft Rd.
Austin, TX 78746

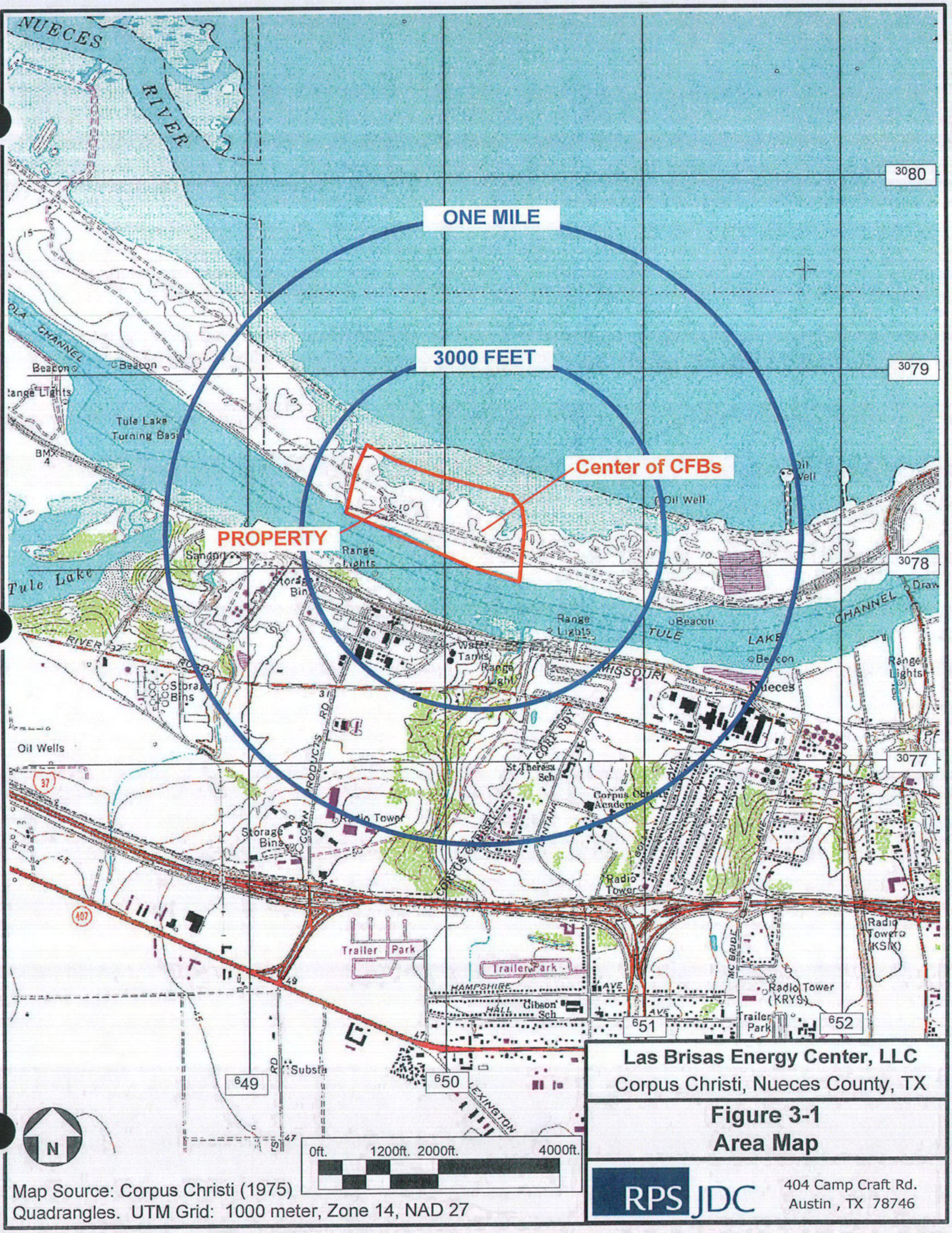


NOTE:
Diesel tanks EPNs are not shown. There is one tank adjacent to each engine.

Las Brisas Energy Center, LLC
Corpus Christi, Nueces County, TX

Figure 3-2
Plot Plan

RPS JDC
404 Camp Craft Rd
Austin, TX 78746



Las Brisas Energy Center, LLC
Corpus Christi, Nueces County, TX

Figure 3-1
Area Map

Las Brisas Exhibit 7
00015

3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM CFB BOILERS

CO_2 emissions from the combustion of petroleum coke in the CFB boilers are calculated using the emission factors (kg/MMBtu) for petroleum coke from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[9] CH_4 and N_2O emission calculations are calculated using the emission factors (kg/MMBtu) for petroleum coke from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[10] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[11]

CO_2 emissions are generated from the use of the sorbent (crushed limestone) in the SO_2 removal system in the CFB boilers in the following manner:

- CO_2 is released from the reaction of $CaCO_3$ with SO_2 by the following reaction: $CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$
- The remaining $CaCO_3$ in the limestone is decomposed due to the heat in the boiler by the following reaction: $CaCO_3 \rightarrow CaO + CO_2$
- The $MgCO_3$ in the limestone is decomposed due to the heat in the boiler by the following reaction: $MgCO_3 \rightarrow MgO + CO_2$.
- Organic carbon compounds in the limestone are oxidized to produced H_2O and CO_2.

CO_2 emissions from the use of $CaCO_3$ in the CFB boilers are calculated using equation G-5 of the Acid Rain Rules. Equation G-5 is used rather than equation G-6 because equation G-5 is based on the total amount of $CaCO_3$ used and equation G-6 is based only on the amount of $CaCO_3$ stoichiometrically required based on the amount of SO_2 removed. An excess of limestone will be added to the CFB boilers to promote the reaction and high removal of SO_2 in the CFB bed. Using equation G-5 accounts to both the CO_2 released from the reaction of $CaCO_3$ with SO_2 and the CO_2 released from the excess $CaCO_3$ in the limestone decomposing in the boilers. Equation G-5 provides as follows:[12]

$SE_{CO2} = W_{CaCO3} \times Fu \times MW_{CO2}/MW_{CaCO3}$ (Eq. G-5)

Where:

SE_{CO2} = CO_2 emitted from sorbent, tons/yr.

W_{CaCO3} = $CaCO_3$ used, tons/yr

Fu = 1.0, the calcium to sulfur stoichiometric ratio.

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[9] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

[10] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

[11] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

[12] 40 C.F.R. 75, Appendix G – *Determination of CO_2 Emissions*

MW $_{CO2}$ = Molecular weight of carbon dioxide, 44.0 lb/lb-mole.

MW $_{CaCO3}$ = Molecular weight of $CaCO_3$, 100.0 lb/lb-mole.

CO_2 emissions from the decomposition of the $MgCO_3$ in the limestone are based on the stoichiometric ratio of one mole of CO_2 generated for each mole of $MgCO_3$ added to the boiler. This is consistent with the GHG reporting calculation method for Cement Production in 40 CFR 98, Subpart H, except that it is based on the amount of $MgCO_3$ input rather than the amount of MgO produced.

CO_2 emissions from the oxidation of organic carbon compounds in the limestone are based on the default factor of 0.2 wt% organic carbon content contained in 40 CFR 98, Subpart H, §98.83(d)(3).

Calculations of GHG emissions from the CFB boilers are presented on Table 3-2.

3.2 GHG EMISSIONS FROM AUXILIARY BOILERS

CO_2 emissions from the natural-gas-fired auxiliary boilers are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[13] CH_4 and N_2O emissions from the auxiliary boilers are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[14] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[15]

Calculations of GHG emissions from the auxiliary boilers are presented on Table 3-3.

3.3 GHG EMISSIONS FROM PROPANE VAPORIZERS

CO_2 emissions from the propane-fired propane vaporizers are calculated using the emission factors (kg/MMBtu) for propane from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[16] CH_4 and N_2O emission from the propane vaporizers are calculated using the emission factors (kg/MMBtu) for propane from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[17] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[18]

Calculations of GHG emissions from the propane vaporizers are presented on Table 3-4.

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[13] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

[14] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

[15] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

[16] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

[17] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

[18] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

3.4 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES

GHG emissions from natural gas piping components are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[19] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[20]

Calculations of GHG emissions from the natural gas piping components are presented on Table 3-5.

3.5 GHG EMISSIONS FROM DIESEL FIRED EMERGENCY ENGINES

CO_2 emission calculations from the diesel-fired emergency generators, fire pump engines and the emergency boiler feed water pump engines are calculated using the emission factors (kg/MMBtu) for Distillate Fuel Oil No. 2 from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[21] CH_4 and N_2O emission calculations from the diesel-fired engines are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[22] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[23]

Calculations of GHG emissions from the emergency engines are presented on Table 3-6.

3.6 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator circuit breakers associated with the proposed unit are calculated using a predicted SF_6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[24]

Calculations of GHG emissions from electric equipment insulated with SF_6 are presented on Table 3-7.

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[19] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production*, 40 C.F.R. Pt. 98, Subpt. W, Tbl. W-1A.

[20] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

[21] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

[22] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2

[23] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

[24] *Id.*

Table 3-1
Plantwide GHG PTE Emission Summary
Las Brisas Energy Center LLC
Corpus Christi, Nueces County, Texas

Status	Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
New	CFB Boiler 1	CFB-1	3,221,718	3,255,305
New	CFB Boiler 2	CFB-2	3,221,718	3,255,305
New	CFB Boiler 3	CFB-3	3,221,718	3,255,305
New	CFB Boiler 4	CFB-4	3,221,718	3,255,305
New	Auxilliary Boiler 1	AUX-BOIL1	26,312	26,337
New	Auxilliary Boiler 2	AUX-BOIL2	26,312	26,337
New	Propane Vaporizer 1	PRO-VAP1	2,711	2,721
New	Propane Vaporizer 2	PRO-VAP2	2,711	2,721
New	Emergency Generator 1	ENG-EG1-1	145	145
New	Emergency Generator 2	ENG-EG1-2	145	145
New	Fire Water Pump	ENG-FWMAIN	23	23
New	Fire Water Booster Pump	ENG-FWB1	6	6
New	Fire Water Booster Pump	ENG-FWB2	6	6
New	Fire Water Booster Pump	ENG-FWB3	6	6
New	Fire Water Booster Pump	ENG-FWB4	6	6
New	Boiler Feed Water Pump	ENG-BFWP1	125	126
New	Boiler Feed Water Pump	ENG-BFWP2	125	126
New	Boiler Feed Water Pump	ENG-BFWP3	125	126
New	Boiler Feed Water Pump	ENG-BFWP4	125	126
New	Natural Gas Piping Fugitives	FUG-NG	3	61
New	Insulated Electrical Equipment	FUG-SF6	0.0014	34
		TOTAL	12,945,757	13,080,273

Table 3-2

GHG Emission Calculations - CFB Boilers

Las Brisas Energy Center LLC

GHG Potential To Emit Emissions From Coke Fired CFB Boilers

GHG Emissions from fuel firing

EPN	Fuel Use[1] (MMBtu/hr coke)	Annual Operation (hr/yr)	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
CFB-1 through CFB-4 (each unit)	3,080	8760	26,980,800	CO_2	102.04	3,034,765	1	3,034,765.1
				CH_4	1.1E-02	327.15	21	6,870.2
				N_2O	1.6E-03	47.59	310	14,751.5
					Totals	**3,035,139.8**		**3,056,386.8**

Note

1. *Annual fuel usage from State/PSD air permit application*
2. *Factors from Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

GHG Emissions from Limestone Calcination

Calculations are for each unit

EPN	Maximum Heat Input (MMBtu/yr)	Limestone Used[4] TPY	$CaCO_3$ Used[4] (tpy)	$MgCO_3$ Used[4] (tpy)	CO_2 From $CaCO_3$ [5] (tpy)	CO_2 From $MgCO_3$ [6] (tpy)[4]	CO_2 From Organic Carbon in Limestone[7] (tpy)	Total CO_2 (tpy)	Global Warming Potential[3]	CO_2e (tpy)	Emission Factor From Limestone Calcination kg CO_2e/MMBtu
CFB-1 through CFB-4 (each unit)	26,980,800	424,041	388,888	14,333	186,578	9,231	3,110	198,918	1	198,918	6.69

Note

4. *Calculation of Limestone, $CaCO_3$, $MgCO_3$ Usage*

Fuel Sulfur =	6.7	wt% (annual average)
Fuel HHV =	13,800	Btu/lb
Fuel Sulfur Input =	4.86	lb S/MMBtu
Potential SO_2 output =	9.71	lb SO_2/MMBtu
Ca/S Ratio =	1.90	(an excess of limestone is added to promote the reaction and high removal of SO_2 in the CFB bed)
$CaCO_3$ Usage =	28.8	lb $CaCO_3$/MMBtu
Avg. $CaCO_3$ wt% in Limestone =	91.7%	(From TCEQ PSD Application)
Avg. $MgCO_3$ wt% in Limestone =	3.4%	(From TCEQ PSD Application)
Limestone Usage =	31.43	lb limestone/MMBtu
$MgCO_3$ Usage =	1.06	lb $MgCO_3$/MMBtu

Table 3-2

GHG Emission Calculations - CFB Boilers

Las Brisas Energy Center LLC

5. *$SE_{CO2} = W_{CaCO3} * Fu * MW_{CO2}/MW_{CaCO3}$ + (40 CFR Part 75 Appendix G, Equation G-5)*

where,

SE_{CO2} = CO_2 emitted from sorbent, ton/yr

W_{CaCO3} = $CaCO_3$ used, ton/yr

Fu = 1.0, the calcium to sulfur stoichiometric ratio

MW_{CO2} = molecular weight of CO_2 = 44

MW_{CaCO3} = molecular weight of $CaCO_3$ = 100

6. *CO_2 liberated from $MgCO_3$*

$MgCO_3$ => $MgO + CO_2$

CO_2 ton/yr =

$MgCO_3$ ton	2000 lb	lbmole $MgCO_3$	1 lbmole CO_2	44 lb CO_2	ton
yr	ton	68.32 lb $MgCO_3$	1 lbmole $MgCO_3$	lbmole CO_2	2000 lb

7. CO_2 Emissions from Organic Carbon Content of Limestone

Organic Carbon Content of Limestone = 0.2 wt% default value from 40 CFR 98, Subpart H, Equation H-5

CO_2 ton/yr =

Limestone ton	2000 lb	0.002 lb C	lbmole C	1 lbmole CO_2	44 lb CO_2	ton
yr	ton	lb limestone	12 lb C	1 lbmole C	lbmole CO_2	2000 lb

TOTAL GHG Emissions

EPN	Pollutant	GHG Mass Emissions (tpy)	CO_2e (tpy)
CFB-1 through CFB-4 (each unit)	CO_2	3,221,343	3,233,683.2
	CH_4	327	6,870.2
	N_2O	48	14,751.5
	Totals	**3,221,717.7**	**3,255,304.8**

MSS Emissions Comparison

Operation Mode	Fuel Type	Fuel Use [8] MMBtu/hr	Emission factor [9] CO - lb/MMBtu	Emission factor [9] CH_4 - lb/MMBtu	Emission factor [9] N_2O - lb/MMBtu	Emissions CO -lb/hr	Emissions CH_4 - lb/hr	Emissions N_2O - lb/hr
Normal Operation	coke	3080.0	224.96	0.0243	0.0035	**692,869**	**75**	**11**
Start-up	coke	770.0	224.96	0.0243	0.0035	173,217	19	3
	natural gas	426.0	116.89	0.00220	0.00022	49,794	1	0
					TOTAL	**223,011**	**20**	**3**

Normal operation emissions are larger.

Note

8. *Start-up fuel use from permit application submitted May 2008.*

9. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, and converted to lbs from kg.*

Table 3-3
GHG Emission Calculations - Auxilliary Boilers
Las Brisas Energy Center LLC

GHG Potential To Emit Emissions From Natural Gas Fired Auxilliary Boilers

Calculations are for each unit

EPN	Fuel Use[1] (MMscf/yr)	HHV of Fuel[1] (MMBtu/MMscf)	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
AUX-BOIL1 and AUX-BOIL2	453.8	992	450,192	CO_2	53.02	26,310.99	1	26,311.0
				CH_4	1.0E-03	0.50	21	10.4
				N_2O	1.0E-04	0.05	310	15.4
					Totals	**26,311.5**		**26,336.8**

Note

1. *Annual fuel use and heating value of natural gas from State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-4

GHG Emission Calculations - Propane Vaporizers

Las Brisas Energy Center LLC

GHG Potential To Emit Emissions From Propane Fired Vaporizers

Calculations are for each unit

EPN	Fuel Use[1] (MMscf/yr)	HHV of Fuel [1] (MMBtu/MMscf)	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
PROP-VAP1 and PROP-VAP1	15.745	2541	40,008	CO_2	61.46	2,710.44	1	2,710.4
				CH_4	3.0E-03	0.13	21	2.8
				N_2O	6.0E-04	0.03	310	8.2
					Totals	**2,710.6**		**2,721.4**

Note

1. *Annual fuel usage and heating value of propane from State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-5
GHG Emission Calculations - Natural Gas Piping
Las Brisas Energy Center LLC

GHG Emissions From New Natural Gas Piping Components

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2[2] (tpy)	Methane[3] (tpy)	Total (tpy)
FUG-NG	Valves	Gas/Vapor	100	0.123	0.123	2.13	
	Flanges	Gas/Vapor	250	0.017	0.043	0.74	
	Relief Valves	Gas/Vapor	1	0.196	0.002	0.03	
GHG Mass-Based Emissions					0.17	2.90	***3.1***
Global Warming Potential[4]					1	21	
CO_2e Emissions					0.17	60.88	***61.1***

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting*
2. *CO_2* emissions based on vol% of CO_2 in natural gas — 2.0% conservative estimate based on typical natural gas
3. *CH_4 emissions based on vol% of CH_4 in natural gas* — 95.0% conservative estimate based on typical natural gas
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

100 valve	0.123 scf gas	0.02 scf CO_2	lbmole	44.01 lb CO_2	8760 hr	ton =	0.12 ton/yr
	hr * valve	scf gas	385.5 scf	lbmole	yr	2000 lb	

Table 3-6

GHG Emission Calculations - Emergency Engines

Las Brisas Energy Center LLC

GHG Emissions Contribution From Diesel Combustion In Emergency Engines

Calculations are for each unit

Assumptions	**Generator**	**Fire Water Pump**	**Fire Water Booster Pump**	**Boiler Feed Water Pump**	
Ann.Operating Schedule	100	100	100	100	hours/year
Power Rating	2,309	360	100	2,000	hp
Brake Specific Fuel Consumption	7,709	7,709	7,709	7,709	Btu/hp-hr
Number of units	2	1	4	4	

EPN	**Heat Input** (MMBtu/hr)	**Pollutant**	**Emission Factor** (kg/MMBtu)[1]	**GHG Mass Emissions** (tpy)	**Global Warming Potential**[2]	**CO_2e** (tpy)
ENG-EG1 & 2 (each unit)	17.8	CO_2	73.96	144.8	1	144.8
		CH_4	3.0E-03	0.01	21	0.1
		N_2O	6.0E-04	0.00	310	0.4
			Totals	**144.82**		**145.3**
ENG-FWMAIN	2.8	CO_2	73.96	22.6	1	22.6
		CH_4	3.0E-03	0.00	21	0.0
		N_2O	6.0E-04	0.000	310	0.1
			Totals	***22.58***		**22.7**
ENG-FWB1 to 4 (each unit)	0.8	CO_2	73.96	6.3	1	6.3
		CH_4	3.0E-03	0.0	21	0.0
		N_2O	6.0E-04	0.0	310	0.0
			Totals	***6.27***		**6.3**
ENG-BFWP1 to 4 (each unit)	15.4	CO_2	73.96	125.4	1	125.4
		CH_4	3.0E-03	0.0	21	0.1
		N_2O	6.0E-04	0.0	310	0.3
			Totals	***125.44***		**125.9**

Calculation Procedure

Annual Emission Rate = heat Input x Emission Factor x 2.2 lbs/kg x hours/year x Global Warming Potential / 2,000 lbs/ton

Note

1. *GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Table 3-7

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

Corpus Christi, Nueces County, Texas

Assumptions

New insulated circuit breaker SF_6 capacity	570	lb
Estimated annual SF_6 leak rate	0.5%	by weight
Estimated annual SF_6 mass emission rate	0.001425	ton/yr
Global Warming Potential[1]	23,900	
Estimated annual CO_2e emission rate	34.1	ton/yr

Note

1. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Because the project emissions increase of GHG is greater than 75,000 ton/yr of CO_2e, PSD is triggered for GHG emissions. The emissions netting analysis is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Note that this is a new greenfield site and, as such, there are no contemporaneous emission changes associated with the project. Also included in Appendix B is the "The GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES" from the *PSD and Title V Permitting Guidance for Greenhouse Gases.*

TCEQ PSD NETTING TABLES

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	85013, PSD-TX-1138, HAP48	Application Submittal Date:	
Company	Las Brisas Energy Center LLC		
RN:	RN105520779	Facility Location:	Corpus Christi
City	Corpus Christi	County:	Nueces
Permit Unit I.D.:	all units	Permit Name:	Electric Generation Facility
Permit Activity:	☑ New Major Source	☐ Modification	
Project or Process Description:	Authorize new CFB boilers and ancillary equipment		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	GHG	CO_2e
	NOx	VOC					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	This form for GHG only					0	0
Proposed project increases (tpy from 2F)[3]						12,945,757	13,080,273
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)	Yes					Yes	Yes
If site is major, is project increase significant? (yes or no)							
If netting required, estimated start of construction:		11/1/12					
5 years prior to start of construction:		11/2/07	Contemporaneous				
estimated start of operation:		1/1/17	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						12,945,757	13,080,273
FNSR applicable? (yes or no)						Yes	Yes

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).

The presentations made above and on the accompanying tables are true and correct to the best of my knowledge.

Signature ____ MANAGING PARTNER 10·28·2011
Signature Title Date

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**GHG**	**Permit:**	**Electric Generation Facility**
Baseline Period:	**N/A**	**to**	**N/A**

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (A-B)[6]	Correction[7]	Project Increase[8]
1	CFB-1	CFB-1	85013	0	0	3,221,718		3,221,718		3,221,718
2	CFB-2	CFB-2	85013	0	0	3,221,718		3,221,718		3,221,718
3	CFB-3	CFB-3	85013	0	0	3,221,718		3,221,718		3,221,718
4	CFB-4	CFB-4	85013	0	0	3,221,718		3,221,718		3,221,718
5	AUX-BOIL1	AUX-BOIL1	85013	0	0	26,312		26,312		26,312
6	AUX-BOIL2	AUX-BOIL2	85013	0	0	26,312		26,312		26,312
7	PRO-VAP1	PRO-VAP1	85013	0	0	2,711		2,711		2,711
8	PRO-VAP2	PRO-VAP2	85013	0	0	2,711		2,711		2,711
9	ENG-EG1-1	ENG-EG1-1	85013	0	0	145		145		145
10	ENG-EG1-2	ENG-EG1-2	85013	0	0	145		145		145
11	ENG-FWMAIN	ENG-FWMAIN	85013	0	0	23		23		23
12	ENG-FWB1	ENG-FWB1	85013	0	0	6		6		6
13	ENG-FWB2	ENG-FWB2	85013	0	0	6		6		6
14	ENG-FWB3	ENG-FWB3	85013	0	0	6		6		6
15	ENG-FWB4	ENG-FWB4	85013	0	0	6		6		6
16	ENG-BFWP1	ENG-BFWP1	85013	0	0	125		125		125
17	ENG-BFWP2	ENG-BFWP2	85013	0	0	125		125		125
18	ENG-BFWP3	ENG-BFWP3	85013	0	0	125		125		125
19	ENG-BFWP4	ENG-BFWP4	85013	0	0	125		125		125
20	FUG-NG	FUG-NG	85013	0	0	3		3		3
21	FUG-SF6	FUG-SF6	85013	0	0	0.0014		0.0014		0.0014
									Total	12,945,757

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) - Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**CO2e**	**Permit:**	**Electric Generation Facility**
Baseline Period:	**N/A**	**to**	**N/A**

Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (A-B)[6]	Correction[7]	Project Increase[8]
	FIN	EPN								
1	CFB-1	CFB-1	85013	0	0	3,255,305		3,255,305		3,255,305
2	CFB-2	CFB-2	85013	0	0	3,255,305		3,255,305		3,255,305
3	CFB-3	CFB-3	85013	0	0	3,255,305		3,255,305		3,255,305
4	CFB-4	CFB-4	85013	0	0	3,255,305		3,255,305		3,255,305
5	AUX-BOIL1	AUX-BOIL1	85013	0	0	26,337		26,337		26,337
6	AUX-BOIL2	AUX-BOIL2	85013	0	0	26,337		26,337		26,337
7	PRO-VAP1	PRO-VAP1	85013	0	0	2,721		2,721		2,721
8	PRO-VAP2	PRO-VAP2	85013	0	0	2,721		2,721		2,721
9	ENG-EG1-1	ENG-EG1-1	85013	0	0	145		145		145
10	ENG-EG1-2	ENG-EG1-2	85013	0	0	145		145		145
11	ENG-FWMAIN	ENG-FWMAIN	85013	0	0	23		23		23
12	ENG-FWB1	ENG-FWB1	85013	0	0	6		6		6
13	ENG-FWB2	ENG-FWB2	85013	0	0	6		6		6
14	ENG-FWB3	ENG-FWB3	85013	0	0	6		6		6
15	ENG-FWB4	ENG-FWB4	85013	0	0	6		6		6
16	ENG-BFWP1	ENG-BFWP1	85013	0	0	126		126		126
17	ENG-BFWP2	ENG-BFWP2	85013	0	0	126		126		126
18	ENG-BFWP3	ENG-BFWP3	85013	0	0	126		126		126
19	ENG-BFWP4	ENG-BFWP4	85013	0	0	126		126		126
20	FUG-NG	FUG-NG	85013	0	0	61		61		61
21	FUG-SF6	FUG-SF6	85013	0	0	34		34		34
									Total	13,080,273

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) - Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

5.1 DEFINITION OF BACT

The EPA's BACT requirements are set forth in section 165(a)(4) of the Clean Air Act and in federal regulation at 40 CFR 52.21. 40 CFR 52.21 defines Best Available Control Technology as:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[25]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[26] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option and the top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

---

[25] 40 C.F.R. § 52.21(b)(12.)

[26] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Mar. 2011).

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

5.2 BACT FOR THE CFB BOILERS

5.2.1 Step 1: Identify All Available Control Technologies

5.2.1.1 *Inherently Lower-Emitting Processes/Practices/Designs*

A summary of available, lower greenhouse gas emitting processes, practices, and designs for CFB boilers is presented below. However, EPA must also be mindful of the fact that the State of Texas has issued a PSD permit for LBEC that contemplates CFB technology.

5.2.1.1.1 CFB Boiler Energy Efficiency

Las Brisas will consist of four steam-electric generating units and related support facilities. The highly-efficient LBEC steam-electric generating units will burn 100% petroleum coke, a product of nearby refineries. One measure of a steam-electric generating unit's efficiency is its "heat rate," which is expressed as the number of British thermal units (Btu) needed to produce a kilowatt-hour or kWh of energy. The lower a unit's heat rate the more efficient it is. Las Brisas' guaranteed full load net plant heat rate will be 9,275 Btu/kWh. For 2009, the average operating heat rate for petroleum-fired (includes petroleum coke-fired) steam-electric generating units in the United States was 11,002 Btu/kWh. *See* U.S. Energy Information Administration, Electric Power Annual 2009 at 49, Table 5.3, available at http://www.eia.doe.gov/cneaf/electricity/epa/ epa_sum.html.

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies, so that as much of the energy content of the fuel as possible goes into generating power.

Steam Generator Design

The steam generators (boilers) proposed for Las Brisas plant are heat exchangers designed to capture as much thermal energy as possible from the combustion process. This is accomplished through heat recovery at a high pressure level utilizing an economizer, evaporator section, and superheater sections. Furthermore, thermal energy will be recovered in steam reheaters to improve thermal cycle efficiency. These heat transfer sections will be made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Many of the tubes in the convective backpass of the boiler will also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the steam generator.

Feed Water Heaters and Economizer

Feedwater heaters improve cycle efficiency through extracting steam from the steam turbine flow path and utilizing that steam to preheat feedwater to the steam generator via multiple increments of heating. In this manner, the thermodynamic efficiency of the system is improved by reducing the irreversibilities involved with steam generation. This is traditionally called regenerative feedwater heating where the steam is partially expanded through the steam turbine to produce useful electric generation and then extracted at multiple pressure levels such that the remaining energy in the steam is recovered within the thermal cycle rather than exhausted to the condenser.

The LBEC feedwater system will be designed with 7 stages of regenerative heaters. The influence of feedwater heating on overall thermal cycle efficiency for a cycle with 7 stages of feedwater heating as compared to a thermal cycle with a single feedwater heater can be estimated as an approximate improvement of 1.5 to 1.75 percent in higher heating value, net plant efficiency. This is generally equivalent to an improvement in net plant heat rate and resultant reduction in fuel consumption of approximately 4.4 percent.

Fluidized Stripper-Coolers

The spent bottom ash from the boiler furnace will be cooled in a fluidized stripper-cooler. Water from the condenser will be used to cool the ash to a temperature at which conventional ash disposal equipment can be utilized. This water recovers heat from the bottom ash and returns it to the feed water system thus adding another element of efficiency to the overall system.

Boiler Feed Water Pumps

Large pumps are used to deliver the pre-heated water to the boiler. These pumps can be driven by electric motor or by a dedicated steam turbine driver. Steam turbine drivers convert thermal energy extracted from the steam turbine cycle directly to the mechanical pumping energy required and are not a parasitic electrical load in the system. Electric drives require additional energy conversion processes (thermal to mechanical, mechanical to electrical, and electrical back to mechanical), with their associated conversion inefficiencies to achieve the same pumping capacity. Where steam is available, using a steam turbine drive eliminates the inherent losses in the energy conversion process from mechanical to electrical and electrical back to mechanical. To best optimize system efficiencies, the steam exhaust from the steam turbine drive will be recovered and returned to the feed water system through the deaerator to increase the temperature of the feed water entering the boiler. Las Brisas will be equipped with steam turbine drivers for the boiler feed water pumps.

Regenerative Air Heaters

Similar to the boiler feed water, air that enters the boiler combustion system at a higher temperature than the ambient air will increase the efficiency of the system. Each boiler will be equipped with a regenerative air heater that will recover some of the boiler flue gas exhaust energy to “pre-heat” the air introduced into the combustion system.

Insulation

Boilers are designed to maximize the conversion of the thermal combustion energy to steam. One aspect of the boiler design in maximizing this heat conversion is the use of refractory lining systems and mineral fiber insulation. Insulation minimizes heat loss to the surroundings, thereby improving the overall efficiency of the boiler and steam cycle. Insulation will be applied to the panels that make up the shell of the boilers and associated convective heat exchange surfaces. The insulation will also be applied to the exhaust gas air ducts, CFB cyclones, and plenums as wells all the high-temperature steam and water lines throughout the facility.

Minimizing Fouling of Heat Exchange Surfaces

The boilers will be made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion process. To maximize this heat transfer, the tubes and their extended surfaces will be kept as clean as possible since fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the solid ash constituents within the exhaust gas stream. To minimize fouling, steam soot blowers will be utilized to periodically remove deposits from the heat transfer surfaces. Water wash manifolds will also be provided in the regenerative air heater. Additionally, periodic cleaning of the tubes during outages will be performed. By reducing fouling, the thermal efficiency of the unit will be maintained.

Minimizing Vented Steam and Repair of Steam Leaks

Las Brisas will minimize steam vents and will promptly repair steam leaks to maintain the plant’s efficiency. The facility has very few locations where steam will be vented from the system, including at the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the boiler and condenser by removing solids, contaminants, and air that potentially blankets the heat transfer surfaces resulting in reduced equipment performance.

Steam Turbine Design

The steam turbine for this project will be a modern, high-efficiency, reheat, multiple extraction, condensing unit. The overall efficiency of the steam turbine has been maximized by proper design of a number of items, including the inlet steam conditions, extractions for regenerative feed water heating, reheat steam conditions, the exhaust steam conditions, blade design, last stage blading selection, the turbine seals, and the generator efficiency.

Use of Reheat Cycles

The efficiency of a steam turbine is directly related to the steam conditions entering the turbine. The higher the steam temperature and pressure, the higher the overall efficiency. Furthermore, to achieve increased thermal cycle efficiencies, a reheat cycle is employed at Las Brisas. This is implemented to increase the amount of recoverable energy within the expansion path of the steam turbine while maintaining an acceptable moisture content in the exhaust steam. If the moisture content of the exhaust steam is too high, erosion of the last-stage turbine blades occurs. This cycle reheats partially expanded steam from the steam turbine to increase unit efficiency..

Use of Exhaust Steam Condenser
Steam turbine efficiency is also improved by lowering the exhaust steam pressure of the unit. Generally, the lower the exhaust pressure, the higher the overall turbine efficiency. For high-efficiency units, such as Las Brisas, the exhaust steam is wet or saturated under vacuum conditions. This is accomplished by the use of a condenser with vacuum pumps or air ejectors. The condenser is typically a shell and tube heat exchanger with cooling water flowing through the tubes and the turbine exhaust steam condensing in the shell. The condensing steam creates a vacuum in the condenser, which allows the steam to expand to a lower pressure, increasing the amount of recoverable energy and power generation and thus increasing the steam turbine efficiency. This vacuum is dependent on the temperature of the cooling water. As the temperature of the cooling water is lowered, the absolute vacuum attainable is lowered and the steam turbine cycle is more efficient.

Efficient Generator Design
The generator is also a key element in the overall performance of the unit. The modern generator is a high-efficiency unit. The generator for modern steam turbines is typically cooled by one of three methods. These methods are open-air cooling, totally enclosed water to air cooling, or hydrogen cooling. Of the three methods, water and hydrogen cooling are the most efficient due to the unit's ability to maintain lower coil temperatures and resulting in fewer stray losses in the generator. The steam turbine generator for this project will have water cooled stator windings and will have a hydrogen-cooled rotor.

5.2.1.1.2 Use of Lower GHG Emitting Fuel

The EPA provided the following guidance regarding the use of lower GHG emitting fuel as a BACT consideration:

> *Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel type (i.e., coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit. Furthermore, when a permit applicant has incorporated a particular fuel into one aspect of the project design (such as startup or auxiliary applications), this suggests that a fuel is "available" to a permit applicant. In such circumstances, greater utilization of a fuel that the applicant is already proposing to use in some aspect of the project design*

> *should be listed as an option in Step 1 unless it can be demonstrated that such an option would disrupt the applicant's basic business purpose for the proposed facility.*[27]

It is unquestionable that petroleum coke will continue to be generated as part of the petroleum refining process, with approximately 1.7 million tons per year produced in Corpus Christi and approximately 35 million tons produced throughout other parts of the Gulf Coast region. Presently, the majority of Gulf Coast petroleum coke is transported to remote international markets where it is burned in cement kilns, power plants, and other processes. Because this petroleum coke will continue to be generated, shipped abroad, and burned in these processes in the absence of a local consumer, the LBEC is expected to result in a net decrease in global GHG (and other) emissions, as it will (1) eliminate the GHG emissions associated with the transportation of locally produced petroleum coke to international markets, and (2) reduce the amount of GHG emissions generated from burning the petroleum coke for energy recovery because the LBEC boilers and turbines are more efficient than the existing processes currently combusting the petroleum coke.

Natural gas will be utilized during startups to initiate the combustion process and to heat the boiler and fuel bed to a level where the petroleum coke combustion will be self-sustaining and stable. At that point, which will be typically 40% to 50% capacity, the gas system will be turned off. The CFB boilers are not designed to be fired 100% with natural gas. The use of natural gas as a primary fuel is contradictory to the fundamental elements of LBEC's business plan.

5.2.1.2 Add-On Controls

In addition to the power generation process technology options discussed above, it is appropriate to consider add-on technologies as possible ways to capture GHG emissions that are emitted from petroleum coke combustion in the proposed project's CFB boilers and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that concentrate CO_2 from combustion process flue gas, and then inject it into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Emerging CO_2 capture technologies that have been identified as potentially applicable to CFB boiler operation include post-combustion chemical absorption and oxy-combustion. Post-combustion chemical absorption processes have focused primarily on the use of amines and chilled ammonia as solvents. In contrast, oxy-combustion is a process that burns fuel with a highly concentrated oxygen stream in order to increase the outlet concentration of CO_2, thereby reducing the need for a post-combustion CO_2 concentration step.

Amine absorption has been commercially applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, but is only currently being applied to solid fuel-fired power plant boilers on a research and development basis. The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of the current status of chemical-based post-combustion CO_2 capture technology and related costs:

[27] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases, March 2011,* at 48-49.

> "…Absorption processes based on chemical solvents such as amines have been developed and deployed commercially in certain industries. To date, however, their use in pulverized coal (PC) power plants has been restricted to slipstream applications, and no definitive analysis exists as to the actual costs for a full-scale capture plant. Preliminary analysis conducted at NETL indicates that CO_2 capture via amine scrubbing and compression to 2,200 psia could raise the cost of electricity from a new supercritical PC power plant by 65 percent, from 5.0 cents per kilowatt-hour to 8.25 cents per kilowatt-hour…"[28]

The DOE-NETL adds:

> "…Separating CO_2 from this flue gas stream is challenging for several reasons:
>
> - CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems[29] and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system…"[30]

If CO_2 capture could be achieved at a power plant, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

> "Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and

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[28] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Sept. 28, 2011).

[29] CO_2 concentrations in exhausts from the project's petroleum coke-fired boilers will be similar to coal-fired boilers.

[30] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Sept. 28, 2011).

geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…"[31]

5.2.2 Step 2: Eliminate Technically Infeasible Options

In this section, Las Brisas addresses the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's petroleum coke-fired fluidized bed boilers. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

5.2.2.1 *CO_2 Capture, Compression, and Transport*

Though amine absorption technology for CO_2 capture has been utilized in the petroleum refining and natural gas processing industries in high pressure, pre-combustion applications and to exhausts from small-scale gas-fired industrial boilers in post combustion application, it is not yet commercially available for post-combustion application in large scale solid fuel-fired boilers used for power generation, which have considerably larger flow volumes and considerably lower CO_2 concentrations than other processes. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

> "Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[32]

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[31] DOE-NETL, ***Carbon Sequestration:** Geologic Storage Focus Area*, http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited Sept. 28, 2011)

[32] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

In its current CCS research program plans, the DOE-NETL confirms that commercial CO_2 capture technology for large-scale power plant boilers is not yet available and suggests that it may not be available until at least 2020:

> "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:
>
> (1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
>
> (2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;
>
> (3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;
>
> (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."[33]

To corroborate that commercial availability of CO_2 capture technology for large-scale power plant projects will not occur for several more years, Alstom, one of the major developers of commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web site that its CO_2 capture technology will become commercially available in 2015.[34] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be able to handle the volume of CO_2 emissions generated by a project of the size of Las Brisas. The "large-scale demonstration project" to which Alstom refers on its web site would be able to capture 1 million tons of CO_2 per year, an order of magnitude less than the CO_2 generated by the Las Brisas project.

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported if a pipeline was constructed are delineated on the map found at the end of Section 5.[35] The potential length of such a CO_2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO_2 storage.

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[33] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

[34] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited Sept.28, 2011).

[35] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100 (last visited Sept.28, 2011).

The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southwest Regional Partnership on Carbon Sequestration's (SWP) SACROC test site, which is located in Scurry County, Texas approximately 395 miles away (see the map at the end of Section 5 for the test site location). Therefore, to access this potentially large-scale storage capacity site, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

5.2.2.2 *CO_2 Storage*

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[36] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with such recognized potential for some geological storage of CO_2 are located within 5 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit, i.e., SWP's SACROC test site is located in Scurry County, Texas approximately 395 miles away. It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

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[36] *Id.*

Based on the reasons provided above, LBEC believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis.

5.2.3 Step 3: Rank Remaining Control Technologies

As documented above, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1 of this application are being proposed for this project, a ranking of the control technologies is not necessary for this application.

5.2.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application. Because the CCS add-on control option discussed in Section 5.1.2 was determined to be technically infeasible, an examination of the energy, environmental, and economic impacts of that option is not necessary for this application.

5.2.5 Step 5: Select BACT

Las Brisas proposes as BACT for this project, to utilize energy efficient equipment in the plant design and follow the manufacturer's recommended operating and maintenance procedures. To determine the appropriate output-based GHG BACT limit, Las Brisas started with the CFB's design net heat rate and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The guaranteed design heat rate for the CFB boilers is as follows:

Las Brisas CFB Boiler Design Net Heat Rate		
Base Load	90% Boiler Continuous Steam Rating	75% Boiler Continuous Steam Rating
9,137 Btu/kWhr	9,247 Btu/kWhr	9,433 Btu/kWhr

Note that this rate reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant.

To determine an appropriate net output based BACT limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 5% design margin reflecting the CFB boiler provider's performance guarantee
- A 6% performance margin reflecting CFB boiler efficiency degradation over a 25-year period
- A 3% performance margin reflecting degradation of auxiliary plant equipment due to use over time and variability in CFB boiler efficiency due to petroleum coke fuel variability

To account for reduced load operation over the course of a year, Las Brisas is proposing a net, output based BACT emission rate of 1.28 ton CO_2e/MW-hr (2.55 lb CO_2e/kW-hr) on a 12-month rolling average, which is derived from the design net heat rate at 75% boiler continuous steam rating, and adding the above compliance margins. Calculation of the net heat rate and the equivalent ton CO_2e/MWhr are provided on Table 5-1 of this application.

Las Brisas performed a search of the EPA's RACT/BACT/LAER Clearinghouse for solid-fuel-fired electric generating units and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by the Wolverine Power Supply Cooperative for a solid-fuel-fired power plant. A discussion of Las Brisas' proposed BACT as compared to the Wolverine project is provided below:

The Wolverine Power Supply Cooperative air permit application proposed the construction of two, 3,030 MMBtu/hr, circulating fluidized bed boilers firing coal, petroleum coke, and biomass to be located in Rogers City, Michigan. The Permit to Construct, issued on July 29, 2011 listed a GHG BACT limit of 2.1 lb CO_2e/kW-hr, gross output, 12-month rolling average. Note that the BACT limit is based on gross electrical output and not net electrical output. This limit was calculated assuming that a CFB boiler was operating at base load of 660 MW (gross) for 8,760 hours per year. The BACT limit did not account for reduced efficiencies at lower operating loads. The Wolverine BACT limit was also based on a CO_2 emission factor for a subbituminous coal/petroleum coke/bio-mass mixture of 221.5 lb CO_2/MMBtu versus the emission factor for 100% petroleum coke combustion of 225.0 lb CO_2/MMBtu. For direct comparison purposes, the "design" net heat rate for each CFB boiler represented in the Wolverine application was 9,180 Btu/kW-hr (net) compared to Las Brisas' "design" net heat rate of 9,137 Btu/kW-hr (net), making Las Brisas' CFB boilers slightly more efficient than the Wolverine CFB boilers on a "design" net electrical output basis.

5.3 BACT FOR SF_6 INSULATED ELECTRICAL EQUIPMENT

5.3.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The predominate technology used is state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[37]

5.3.2 Step 2: Eliminate Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[38] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF_6.

5.3.3 Step 3: Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

5.3.4 Step 4: Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.3.5 Step 5: Select BACT

Based on this top-down analysis, Las Brisas concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards

[37] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[38] *Id.* at 28 – 29.

Institute (ANSI) C37.013 standard for high voltage circuit breakers.[39] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

Las Brisas will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[40] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

5.4 BACT FOR AUXILIARY BOILERS AND PROPANE VAPORIZERS

Two nominally rated 180 MMBtu/hr auxiliary boilers (EPNs AUX-BOIL1 and AUX-BOILL2) will be utilized during start-up and shutdown activities to provide auxiliary steam which may be required to stabilize the system. Each auxiliary boiler will be limited to 2,500 hours of operation per year.

Two nominally rated 16 MMBtu/hr propane vaporizers (EPNs: PROP-VAP1 and PROP-VAP2) will be utilized as a source of CFB start-up fuel in the event natural gas is not available. Each vaporizer will be limited to 2,500 hours of operation per year.

The combined calculated GHG emissions from the two auxiliary boilers and the two propane vaporizers represent less than 0.5% of the total proposed GHG emissions from the site. LBEC proposes as BACT for this project, to follow manufacturer's recommended operating and maintenance procedures.

Among other recently issued or currently pending GHG permits, the Wolverine Power Supply Cooperative permit and the Palmdale Hybrid Power Project permit included BACT determinations for limited use, auxiliary boilers and heaters. The Wolverine Permit included a 72.4 MMBtu/hr diesel-fired auxiliary boiler, limited to 4,000 hours operation per year. The Permit listed BACT for GHG for the auxiliary boiler to incorporate energy efficient equipment wherever practical in the design of the auxiliary boiler. The Wolverine Permit did not include an output based BACT limit for the auxiliary boiler.

The application for the Palmdale Hybrid Power Project (PHPP) was submitted in May 2011 and a draft permit was issued by the Antelope Valley Air Quality Management District in August 2011. The PHPP application proposed the construction of a power plant utilizing natural-gas-fired combustion turbine combined cycle generators located in Palmdale, California. The project also included a 110 MMBtu/hr natural-gas-fired auxiliary boiler, limited to 500 hours per year operation, and a 40 MMBtu/hr natural-gas-fired heater, limited to 1,000 hours per year

[39] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.
[40] *See* 40 C.F.R. Pt. 98, Subpt. DD.

operation. The Palmdale Permit listed BACT for GHG for the auxiliary boiler and heater as annual tune-ups. The Palmdale Permit did not include an output based BACT limit for the auxiliary boiler or heater.

5.5 BACT FOR EMERGENCY ENGINES

The proposed project will include installation of high efficiency diesel-fired emergency generators, fire water pump engines, and emergency boiler feed water pump engines. The use of diesel is being used as fuel for the emergency engines in the event of unavailability of a natural gas supply. Use of these engines for purpose of maintenance checks and readiness testing will be limited to 100 hours per year each. The new engines will be subject to the New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines.[41] As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use.

The use of engines with a low annual capacity factor and following manufacturer's recommended operating and maintenance procedures is proposed as BACT for GHG emissions.

[41] *See* 40 C.F.R. Pt. 60, Subpt. IIII.

MAP OF EXISTING CO_2 PIPELINES AND POTENTIAL GEOLOGIC STORAGE SITES IN TEXAS

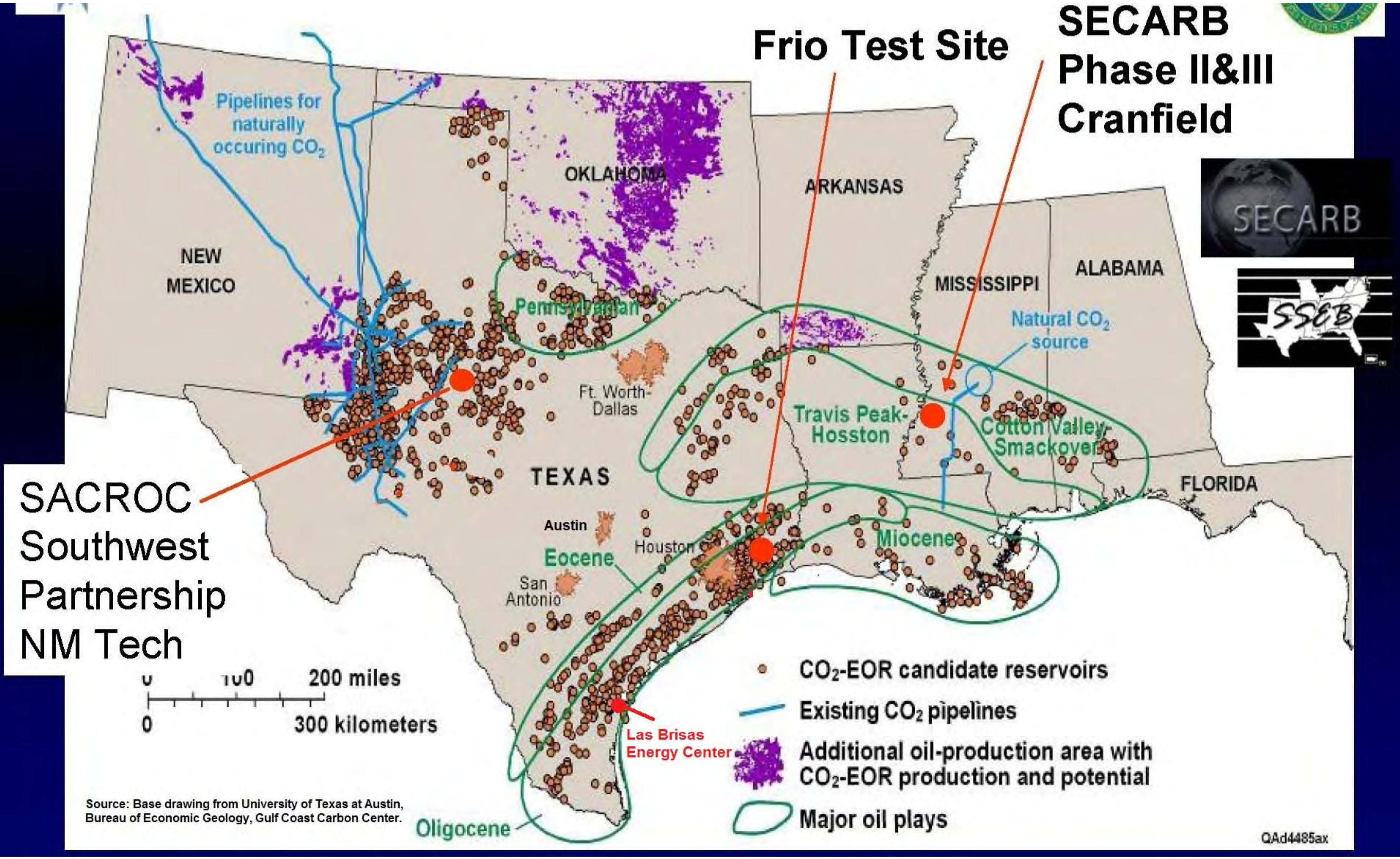

Frio Test Site
SECARB
Phase II&III
Cranfield
SECARB
SSEB
Pipelines for
naturally
occuring CO_2
OKLAHOMA
ARKANSAS
NEW
MEXICO
MISSISSIPPI
ALABAMA
Pennsylvanian
Natural CO_2
source
Ft. Worth-
Dallas
Travis Peak-
Hosston
Cotton Valley-
Smackover
TEXAS
FLORIDA
SACROC
Southwest
Partnership
NM Tech
Austin
Houston
Eocene
Miocene
San
Antonio
200 miles
0
300 kilometers
Las Brisas
Energy Center
CO_2-EOR candidate reservoirs
Existing CO_2 pipelines
Additional oil-production area with
CO_2-EOR production and potential
Major oil plays
Source: Base drawing from University of Texas at Austin,
Bureau of Economic Geology, Gulf Coast Carbon Center.
Oligocene
QAd4485ax

Table 5-1

Calculation of Output Based BACT Limit

Las Brisas Energy Center LLC

	Base Load	90% Load	75% Load	
Design Net Heat Rate	9,137	9247	9433	Btu/kWh (HHV)
	5%	5%	3%	Manufacturer's Guarantee Design Margin
	6%	6%	6%	Degradation Margin for CFB Boilers
	3%	3%	3%	Margin for Degradation of Auxiliary Equipment and Fuel Variability
Calculated Net Heat Rate with Compliance Margins	10,474.6	10,600.7	10,607.9	Btu/kWH (HHV)

Calculate of Annual Average ton CO2e/MWh Limit for each CFB

Annual Average Heat Rate Btu/kW-hr (HHV, Net)	Heat Input Required to Produce 1 MW (MMBtu/yr)		Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions (ton/MWhr)	Global Warming Potential[2]	CO_2e (ton/MWhr)
10,607.9	10.61	Limestone calcination	CO_2	6.69	0.078	1	0.07821
		Pet Coke combustion	CO_2	102.0400	1.193	1	1.19316
		Pet Coke combustion	CH_4	0.0110	0.00006	21	0.00123
		Pet Coke combustion	N_2O	0.0016	0.00001	310	0.00263
				Totals	**1.27**		1.28

2.55 lb CO2e/kW-hr

Note

1. *Petroleum Coke combustion factors from Table C-1 and C-2 of 40 CFR Part 98*
   CO_2 emission factor for limestone calcination calculated on Table 3-1
2. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

6.0 OTHER PSD REQUIREMENTS

6.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[42]

An impacts analysis for non-GHG emissions was submitted with the application for TCEQ Permit No. 85013/PSD-TX-1138/HAP-48.

6.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[43]

6.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and*

[42] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49.

[43] *Id.* at 49.

> *impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.*[44]

An additional mpacts analysis for non-GHG emissions was submitted with the application for TCEQ Permit No. 85013/PSD-TX-1138/HAP-48.

[44] *Id.*

7.0 GHG MONITORING

CO_2 emissions from the CFB Boilers will be measured by installing an exhaust gas flow monitoring system in accordance with the requirements of 40 CFR 75.10(a)(1) and a continuous CO_2 emission monitoring system in accordance with the requirements of 40 CFR §75.10(a)(3)(i). Emissions of CH_4 and N_2O from the CFB boilers will be calculated annually based on the annual heat input and emission factors from Table C-2 to Subpart C of 40 CFR Part 98

CO_2, CH_4, and N_2O emissions from the auxiliary boilers and the propane vaporizers will be calculated annually based on emission factors from Tables C-1 and C-2 of 40 CFR Part 98, Subpart C, General Stationary Fuel Combustion Sources.

CH_4 emissions from natural gas piping fugitives will be calculated annually based on emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems.

SF_6 emissions from the generator circuit breakers will be calculated annually in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting Rules for Electrical Transmission and Distribution Equipment.

APPENDIX A

COPY OF PERMITS 85013, HAP48, AND PSDTX1138

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A PERMIT IS HEREBY ISSUED TO
Las Brisas Energy Center, LLC
AUTHORIZING THE CONSTRUCTION AND OPERATION OF
Petroleum Coke-Fired Electric Generation Facility
LOCATED AT **Corpus Christi, Nueces County, Texas**
LATITUDE 27° 49′ 11″ LONGITUDE 97° 28′ 34″

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code § 116.116 (30 TAC § 116.116)]

2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120(a), (b) and (c)]

3. **Construction Progress.** Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]

4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify to the Office of Permitting and Registration the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC § 116.115(b)(2)(B)]

5. **Sampling Requirements.** If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]

7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]

8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC § 116.115(b)(2)(F)]

9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with §§ 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC § 116.115(b)(2)(G)]

10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]

11. This permit may be appealed pursuant to 30 TAC § 50.139.

12. This permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]

13. There may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]

14. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in TCAA § 382.003(3) or violate TCAA § 382.085, as codified in the Texas Health and Safety Code. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.

TCEQ Docket No.: 2009-0033-AIR
PERMITS 85013, HAP48, and PSDTX1138

Date: ______________________________

____
For the Commission

SPECIAL CONDITIONS

Permit Numbers 85013, HAP48, and PSD-TX-1138

EMISSION RATES AND PERMIT REPRESENTATIONS

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates," and those sources are limited to the emission limits and other conditions specified in that attached table. This permit authorizes planned start-up and shutdown (SS) activities that comply with the emission limits in the maximum allowable emission rates table (MAERT) and the opacity limit of Special Condition No. 10. Compliance with the annual emission limits shall be based on throughput for a rolling 12-month year rather than the calendar year.

2. Emission limits are based upon representations in the permit application dated May 19, 2008, and subsequent updates dated October 3, November 12, December 11, December 29, and December 31, 2008; and January 5, 2009.

FEDERAL APPLICABILITY

3. The Circulating Fluidized Bed (CFB) Boilers, identified as Emission Point Nos. (EPNs) CFB1, CFB2, CFB3, and CFB4, shall comply with applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations in Title 40 Code of Federal Regulations (40 CFR) Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Conditions, and Subpart Db, Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

4. The Auxiliary Boilers, identified as EPNs AUX-BOIL1 and AUX-BOIL2, shall comply with the applicable requirements of 40 CFR Part 60, Subpart A and Subpart Db, Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

5. The Stationary Diesel Engines, identified as EPNs ENG-EG1, ENG-EG2, ENG-FWMAIN, ENG-FWB1, ENG-FWB2, ENG-FWB3, ENG-FWB4, ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4, shall comply with the applicable requirements of 40 CFR Part 60, Subpart A and Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

6. The Stationary Diesel Engines, identified as EPNs ENG-EG1, ENG-EG2, ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4, shall comply with the initial notification requirements of 40 CFR § 63.6645(h), as specified in 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, § 63.6590(b)(1)(i).

7. If any condition of this permit is more stringent than the regulations identified in Special Condition Nos. 3 through 6, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

FUEL SPECIFICATIONS, OPERATING LIMITATIONS, PERFORMANCE STANDARDS, AND CONSTRUCTION SPECIFICATIONS

8. Fuel fired in the CFB Boilers (EPNs CFB1, CFB2, CFB3, and CFB4) shall be limited to:

   A. Petroleum coke with:

      (1) elemental sulfur content not to exceed a 12-month rolling average of 4.9 pounds sulfur per million British thermal units (lb/MMBtu) of heat input, with the heat input based on fuel higher heating value (HHV); and

      (2) trace metal concentrations not to exceed the concentration limitations identified in Attachment A of this permit.

   B. Pipeline-quality natural gas.

   C. Propane.

   D. Use of any other fuel will require prior approval from the permitting authority.

   E. Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in the CFB Boilers or shall allow air pollution control agency representatives to obtain a sample for analysis.

9. The CFB Boilers (EPNs CFB1, CFB2, CFB3, and CFB4) shall each be limited to a maximum heat input of 3,080 MMBtu/hr, averaged over a calendar month, based on the HHV of the fuel fired.

10. Opacity of emissions from EPNs CFB1, CFB2, CFB3, and CFB4 must not exceed 10 percent, averaged over a six-minute period, except for those periods described in Title 30 Texas Administrative Code § 111.111(a)(1)(E) [30 TAC § 111.111(a)(1)(E)], 40 CFR Part 60, § 60.11(c), or as otherwise allowed by rule or statute.

11. Emissions from the CFB Boilers (EPNs CFB1, CFB2, CFB3, and CFB4) shall not exceed the performance standards in the following tables. The performance standards in these tables shall apply at all times except during periods of start-up and shutdown as identified in the permit application.

A. Standards demonstrated by Continuous Emissions Monitoring Systems (CEMS):

Pollutant[1]	**Performance Standard (lb/MMBtu)**[2]	**Compliance Averaging Period**
NO_x	0.10	Hourly
NO_x	0.070	30-day rolling
SO_2	0.114	30-day rolling
SO_2	0.086	12-month rolling
CO	0.10	12-month rolling
Hg	$0.57(10^{-6})$	12-month rolling
	Performance Standard (ppmv)	
NH_3	10 ppmv	Hourly
NH_3	5 ppmv	12-month rolling

B. Standards demonstrated by Reference Method[3] (RM) testing:

Pollutant[1]	**Performance Standard (lb/MMBtu)**[2]	**Compliance Demonstration Period**
PM/PM_{10} (front-half catch)	0.011	3-hour average
PM/PM_{10} total	0.025[4]	3-hour average
VOC	0.0050	3-hour average
H_2SO_4	0.0045	3-hour average
HCl	0.0044	3-hour average
HF	0.00038	3-hour average

Notes:

[1] NO_x - nitrogen oxides; SO_2 - sulfur dioxide; CO - carbon monoxide; PM - particulate matter; PM_{10} - PM $\leq 10_{\mu m}$ in diameter; VOC - volatile organic compounds; H_2SO_4 - sulfuric acid mist; HCl - hydrogen chloride; HF - hydrogen fluoride; Hg - mercury; NH_3 - ammonia

[2] lb/MMBtu - pounds of emissions per million Btu of heat input. Heat input is based on fuel HHV.
ppmv - parts per million by volume, dry, adjusted to 3 percent oxygen (O_2).

[3] RM - EPA Reference Methods, based on the average of three stack sampling runs to be conducted as prescribed by Special Condition Nos. 28 and 37.

[4] Total PM/PM_{10} including back-half (condensibles) catch of sampling train.

12. In the event that a CEMS for NO_x is not operating for a period longer than one hour while a CFB boiler is operating, the permit holder shall operate at no less than the ammonia feed rate to the selective non-catalytic reduction (SNCR) system that was established during a successful initial performance test (adjusted for load) or at the NO_x-compliant feed rate that was measured prior to the loss of the CEMS (adjusted to load), whichever feed rate is higher.

13. In the event that a CEMS for SO_2 is not operating for a period longer than one hour while a CFB boiler is operating, the permit holder shall operate at no less than the limestone feed rate to the boiler and lime feed rate to the polishing scrubber that were established during a successful initial performance test (adjusted for load) or at the SO_2-compliant feed rates that were measured prior to the loss of the CEMS (adjusted to load), whichever feed rates are higher.

14. A. The holder of this permit shall operate the CFB Boiler and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions during start-up and shutdown (SS) activities, by operating in accordance with a written SS plan. The plan shall include detailed procedures for review of relevant operating parameters of the CFB Boilers and associated air pollution control equipment during SS to make adjustments to minimize excess emissions. The plan shall also address readily foreseeable start-up scenarios, including hot start-ups, and provide for appropriate review of the operational condition of the boiler before initiating start-up.

    B. In order to limit maximum hourly emissions of SO_2, the start-up of the CFBs must be sequenced so that only one CFB at a time is firing petroleum coke while operating in start-up mode.

    C. No bypassing of a CFB baghouse is allowed while the CFB is firing petroleum coke, regardless of whether the CFB is operating in start-up or shutdown mode.

D. Only planned and routine start-up/shutdown operations are authorized by this permit. Emissions resulting from any unscheduled and/or unplanned start-up/shutdown activity associated with an upset (emissions event) are not authorized by this permit.

15. The CFB Boiler Stacks (EPNs CFB1, CFB2, CFB3, and CFB4) shall be approximately 500 feet tall with an exit diameter of approximately 16 feet. Stack sampling ports and platform(s) shall be constructed on each CFB boiler stack as specified in the attachment entitled "Chapter 2, Stack Sampling Facilities," or an alternate design may be approved by the TCEQ Corpus Christi Regional Director.

16. The Auxiliary Boilers (identified as EPNs AUX-BOIL1 and AUX-BOIL2) shall meet the following specifications:

A. Emissions, averaged over 3 hours of operation, while operating at greater than 25 percent load, shall not exceed:

(1) NO_x - 0.035 lb/MMBtu;

(2) CO - 50 ppmvd, at 3 percent O_2; and

(3) Filterable PM - 0.0019 lb/MMBtu.

B. Emissions, averaged over three hours of operation, during start-up, shutdown, or while operating at less than 25 percent load, shall not exceed:

(1) NO_x - 0.10 lb/MMBtu; and

(2) CO - 500 ppmvd, 3 percent oxygen

C. Opacity of emissions shall not exceed 5 percent, averaged over a six-minute period.

D. Fuel shall be limited to pipeline-quality natural gas.

E. Operation of each Auxiliary Boiler shall be limited to a maximum of a 28.5 percent annual capacity factor. Capacity factor is the ratio between the actual heat input during a period of 12 consecutive calendar months and the potential heat input had the boiler operated for 8,760 hours during that 12-month period at the maximum design heat input capacity.

17. The Propane Vaporizers (identified as EPNs PROP-VAP1 and PROP-VAP2) shall meet the following specifications:

A. Emissions, averaged over 3 hours of operation, shall not exceed:

(1) NO_x - 0.10 lb/MMBtu;

(2) CO - 100 ppmvd, at 3 percent O_2; and

(3) Filterable PM - 0.0019 lb/MMBtu.

B. Opacity of emissions shall not exceed 5 percent, averaged over a six-minute period.

C. Fuel shall be limited to propane.

D. Operation of each propane vaporizer shall be limited to a maximum of a 28.5 percent annual capacity factor. Capacity factor is the ratio between the actual heat input during a period of 12 consecutive calendar months and the potential heat input had the boiler operated for 8,760 hours during that 12-month period at the maximum design heat input capacity.

18. The 1,600-kW Diesel-Fired Emergency Generators (identified as EPNs ENG-EG1 and ENG-EG2) and the 2,000-hp Diesel-Fired Boiler Feed Water Pumps (identified as EPNs ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4) shall meet the following specifications:

A. Fuel shall be limited to diesel engine fuel containing no more than 500 parts per million (ppm) by weight sulfur. Purchased diesel engine fuel shall comply with the EPA standards for nonroad diesel fuel in 40 CFR Part 80, Regulation of Fuels and Fuel Additives, in effect at the time of purchase.

B. Operation of each generator and pump shall be limited to a maximum of 500 hours per year.

19. The 360-hp Diesel-Fired Fire Water Pump (identified as EPN ENG-FWMAIN) and the 100-hp Diesel-Fired Fire Water Pumps (identified as EPNs ENG-FWB1, ENG-FWB2, ENG-FWB3, and ENG-FWB4) shall meet the following specifications:

A. Fuel shall be limited to diesel engine fuel containing no more than 500 ppm by weight sulfur. Purchased diesel engine fuel shall comply with the EPA standards for nonroad diesel fuel in 40 CFR Part 80, Regulation of Fuels and Fuel Additives, in effect at the time of purchase.

B. Operation of each pump shall be limited to a maximum of 500 hours per year unless a greater number of hours of operation is required to fight a fire.

CHEMICAL AND FUEL STORAGE

20. Anhydrous ammonia storage is subject to the following requirements.

A. Maximum on-site storage is limited to the two pressure tanks identified in the permit application, each with a nominal capacity of 10,000 gallons.

B. The tanks shall be located within

(1) a physical barrier to vehicular traffic; and

(2) a containment system which is capable of holding the entire volume of material stored.

C. Piping and unloading points shall be protected from impact by falling objects.

D. Each tank vent valve shall be equipped with an alarm which will notify personnel that the relief valve has opened.

E. Tanks shall be vapor balanced to the transport vessel during all tank filling operations. The vapor return line shall be purged back to either the transport vessel or the storage tank after every tank loading operation and prior to disconnection of the line. Interlocks shall be installed so that the unloading pump will not run unless the vapor return line to the transport vessel is connected.

F. All plant personnel assigned to anhydrous ammonia injection operations shall participate in continuing training in safety guidelines for the handling of anhydrous ammonia, to be conducted no less frequently than once every two years; new and transferred personnel shall complete all initial training required for their specific assignments prior to assumption of their new duties.

G. Overhead activity involving the lifting of heavy equipment above the anhydrous ammonia storage area shall not be permitted.

H. The holder of this permit shall maintain a complete emergency response plan at the plant site that describes the course of action to be taken by personnel in the event of an anhydrous ammonia tank or line rupture, or a severe anhydrous ammonia leak. This plan shall include water-mitigation methods, notification of the proper civil authorities, and any potentially affected residences and any other appropriate organizations. This plan shall be made available upon request to representatives of the TCEQ or any local program having jurisdiction.

21. Audio, olfactory, and visual checks for ammonia leaks shall be made once per shift within the operating area.

    A. No later than one hour following detection of a leak, plant personnel shall take one or more of the following actions:

        (1) Locate and isolate the leak; and/or

        (2) Stop the leak by bypassing the leaking equipment or taking equipment out of service.

    B. If the leaking equipment cannot be repaired or replaced within 6 hours, use clamping procedures to prevent the leak until replacement or repair can be performed.

22. In any consecutive 12-month period, the holder of this permit shall not receive more than the following quantities of diesel fuel:

Tank Number	**12-Month Throughput (Gallons)**
TNK-EG1	2,734
TNK-EG2	2,734
TNK-FWMAIN	9,841
TNK-FWB1	54,674
TNK-FWB2	54,674
TNK-FWB3	54,674
TNK-FWB4	54,674

Tank Number	12-Month Throughput (Gallons)
TNK-BFWP1	63,100
TNK-BFWP2	63,100
TNK-BFWP3	63,100
TNK-BFWP4	63,100

MATERIAL HANDLING OPERATING LIMITATIONS AND STANDARDS

23. Permanent plant roads shall be paved with a cohesive hard surface which can be cleaned by sweeping or washing. Other roads shall be sprinkled with water and/or surface crusting agents as necessary to maintain compliance with all TCEQ rules and regulations.

24. No visible emissions may leave the plant property. If visible emissions do leave the plant property, further controls or measures shall be installed and/or implemented to limit visible emissions. A trained observer with delegation from the Executive Director of the TCEQ may determine compliance with this special condition by 40 CFR Part 60, Appendix A, RM 22, or equivalent. As represented in the permit application, petroleum coke and limestone will be brought into the facility property via enclosed conveyors only. Lime, soda ash, sand, and activated carbon will be unloaded pneumatically from trucks and conveyed to bins or silos equipped with baghouses. Fly ash from the boiler exhaust baghouses and bottom ash from the boilers will be pneumatically transferred to storage silos. From the storage silos, the fly ash and bottom ash will be conveyed pneumatically and loaded to tank trucks use a loading spout that creates a seal so that there will be no leakage of fly ash or bottom ash during the loading of tank trucks. The loading spout will utilize a fabric shroud to pull the dust or ash laden air from the tank truck back into the ash silos, where it will be exhausted through the silo baghouses. No materials may be stored in open stockpiles on the facility property. Any spillage of material shall be cleaned up as soon as possible and handled in such a way as to minimize emissions.

25. As determined by a certified opacity observer with delegation from the Executive Director of the TCEQ and according to 40 CFR Part 60, Appendix A, Reference Method 9, or equivalent, opacity of emissions from any single fabric filter baghouse stack listed in Special Condition Nos. 26 and 27, and from load out of fly ash and bottom ash from the storage silos to trucks, shall not exceed 5 percent averaged over a six-minute period. Continuous demonstration of compliance with this special condition is not required.

26. Material handling baghouses, designed to meet an emission limit of 0.01 grain PM per dry standard cubic foot of exhaust, properly installed and in good working order, shall control PM emissions from the following sources:

Source	EPN
Limestone Bunker No. 1	SILO-LMST1
Limestone Bunker No. 2	SILO-LMST2
Limestone Bunker No. 3	SILO-LMST3
Limestone Bunker No. 4	SILO-LMST4
Carbon For ACI Silo No. 1	SILO-ACI1
Carbon For ACI Silo No. 2	SILO-ACI2
Carbon For ACI Silo No. 3	SILO-ACI3
Carbon For ACI Silo No. 4	SILO-ACI4
Lime Silo No. 1	SILO-LIME1
Lime Silo No. 2	SILO-LIME2
Lime Silo No. 3	SILO-LIME3
Lime Silo No. 4	SILO-LIME4
Lime Silo No. 5	SILO-LIME5
Lime Silo No. 6	SILO-LIME6
Lime Silo No. 7	SILO-LIME7
Lime Silo No. 8	SILO-LIME8
Unit 1 Sand Day Bin	BIN-SAND1
Unit 2 Sand Day Bin	BIN-SAND2
Unit 3 Sand Day Bin	BIN-SAND3

Source	EPN
Unit 4 Sand Day Bin	BIN-SAND4
Water Treatment Lime Silo	WT-LIME
Water Treatment Soda Ash Silo	WT-SODA

27. Material handling baghouses, designed to meet an emission limit of 0.005 grain PM per dry standard cubic foot of exhaust, properly installed and in good working order, shall control PM emissions from the following sources:

Source	EPN
Fly Ash Silo No. 1	SILO-FA1
Fly Ash Silo No. 2	SILO-FA2
Fly Ash Silo No. 3	SILO-FA3
Fly Ash Silo No. 4	SILO-FA4
Bottom Ash Silo No. 1	SILO-BA1
Bottom Ash Silo No. 2	SILO-BA2
Bottom Ash Silo No. 3	SILO-BA3
Bottom Ash Silo No. 4	SILO-BA4
Coke Silo No. 1	SILO-COKE1
Coke Silo No. 2	SILO-COKE2
Coke Silo No. 3	SILO-COKE3
Coke Silo No. 4	SILO-COKE4
Coke Silo No. 5	SILO-COKE5
Coke Silo No. 6	SILO-COKE6
Coke Silo No. 7	SILO-COKE7

Source	EPN
Coke Silo No. 8	SILO-COKE8

INITIAL DEMONSTRATION OF COMPLIANCE

28. The holder of this permit shall perform initial stack sampling and other testing to establish the actual quantities of air contaminants being emitted into the atmosphere. Unless otherwise specified in this Special Condition No. 28, the sampling and testing shall be conducted in accordance with the methods and procedures specified in Special Condition No. 29. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

A. For the CFB Boilers (EPNs, CFB1, CFB2, CFB3, and CFB4):

(1) Demonstrate compliance with the performance standards of Special Condition No. 11B and the hourly emission rates of the MAERT, applicable to normal operations, using the average of three one-hour stack sampling test runs for each contaminant.

(2) Air contaminants to be sampled and analyzed under (1) above include: NO_x, SO_2, CO, VOC, H_2SO_4, HCl, HF, PM, PM_{10}, NH_3, and Hg. Diluents to be measured include O_2 or carbon dioxide (CO_2).

(3) Demonstrate compliance with the performance standards of Special Condition No. 10 applicable to normal operations, using the average of 30 six-minute readings as provided in 40 CFR § 60.11(b).

(4) Demonstrate compliance with 40 CFR Part 60, Subparts A and Db, for NO_x, SO_2, PM, and opacity. For NO_x and SO_2, the 30-day test results shall also be used to demonstrate compliance with the 30-day performance specifications for NO_x and SO_2 in Special Condition No. 11A.

(5) Demonstrate compliance with the lb/MMBtu performance standards listed on Attachment A and the lb/hr emission rate for lead listed on the MAERT using the average of three one-hour stack sampling test runs.

(6) Boiler load during testing shall be maintained as follows.

(a) Operate at maximum firing rates for the atmospheric conditions occurring during the test as measured by millions of pounds of steam generated per hour or MW of electric generator output. If during subsequent operations the steam generated as measured by millions of pounds of steam generated per hour or MW of electric generator output is greater than that recorded during the test, stack sampling shall be performed at the new operating condition within 150 days. This sampling may be waived by the TCEQ Air Section Manager of the appropriate TCEQ regional office. At no time may the emission rate exceed the rates specified in the MAERT.

(b) During 30-day average emission testing, the boiler load does not have to be maximum, but the load must be representative of future operating conditions and must include at least one 24-hour period at full load.

B. For the Auxiliary Boilers (EPNs AUX-BOIL1 and AUX-BOIL2):

(1) Demonstrate compliance with the NO_x, CO, and filterable PM performance standards of Special Condition No. 16A and the hourly NO_x and CO emission rates of the MAERT, using the average of three, one-hour stack sampling test runs for each contaminant.

(2) Demonstrate compliance with the opacity limitation of 40 CFR Part 60 Subpart Db and Special Condition No. 16C.

(3) Demonstrate compliance with the SO_2 emission rate of the MAERT through fuel sampling to demonstrate use of pipeline quality natural gas.

(4) Demonstrate compliance with the VOC emission rate of the MAERT through operation of the auxiliary boilers within their design limitations.

C. For the Propane Vaporizers (EPNs PROP-VAP1 and PROP-VAP2):

(1) Demonstrate compliance with the NO_x, CO, and filterable PM performance standards of Special Condition No. 17A and the hourly NO_x and CO emission rates of the MAERT, using the average of three, one-hour stack sampling test runs for each contaminant.

(2) Demonstrate compliance with the opacity limitation of Special Condition No. 17B.

(3) Demonstrate compliance with the SO_2 emission rate of the MAERT through fuel sampling of the propane.

(4) Demonstrate compliance with the VOC emission rate of the MAERT through operation of the propane vaporizers within their design limitations.

D. For at least two material handling/storage baghouses, one from Special Condition No. 26 and one from Special Condition No. 27, to be selected by the Corpus Christi Regional Director of the TCEQ, or his designated representative, sample PM emissions using Reference Method 5 testing to show compliance with the emission limits of Special Condition Nos. 26 and 27.

E. For the Diesel-Fired Emergency Generators (identified as EPNs ENG-EG1 and ENG-EG2) and the Diesel-Fired Boiler Feed Water Pumps (identified as EPNs ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4) demonstrate compliance with the emission rates of the MAERT by showing compliance with the requirements of Special Condition No. 18. For the Diesel-Fired Fire Water Pump (identified as EPN ENG-FWMAIN) and the Diesel-Fired Fire Water Pumps (identified as EPNs ENG-FWB1, ENG-FWB2, ENG-FWB3, and ENG-FWB4) demonstrate compliance with the emission rates of the MAERT by showing compliance with the requirements of Special Condition No. 19.

F. For the Cooling Towers (identified as EPNs CTWR1 and CTWR2) demonstrate compliance with the emission rates of the MAERT by maintaining records that demonstrate that the drift eliminators are designed to limit drift as specified in the permit application, and by inspection of the modules, selected by the TCEQ Corpus Christi Regional Director or his designated representative, for consistency with the specified design, flow bypassing the drift eliminators, and damage to the drift eliminators. The manufacturer's specifications and drawings of the internals shall be provided to facilitate inspection.

G. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Permitting and Registration, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for New Source Performance Standards testing which must have EPA approval shall be submitted to the TCEQ Corpus Christi Regional Office.

H. For each CFB Boiler, sampling as required by this condition shall occur within 30 days after the particular boiler achieves a fuel firing rate of 3,080 MMBtu/hr, but no later than

180 days after initial start-up. The first boiler operating day of 30-day average initial performance testing required by 40 CFR § 60.45b(c) must commence within this time.

I. The deadlines established by this condition may be extended by the TCEQ Corpus Christi Regional Office for good cause shown.

TEST METHODS AND PROCEDURES

29. A. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual, EPA Methods in 40 CFR Part 60, Appendix A and 40 CFR Part 51, Appendix M, EPA Conditional Test Methods, and American Society for Testing and Materials (ASTM) as follows:

(1) Appendix A, Methods 1 through 4, as appropriate, for exhaust flow, diluent, and moisture concentration;

(2) Appendix A, Method 5, 5a through 5i, or 17, modified to include back-half condensibles, for the concentration of PM;

(3) Appendix A, Method 5, 5a through 5i, or 17, for the filterable concentration of PM (front-half catch);

(4) Appendix A, Method 6, 6a, 6c, or 8, for the concentration of SO_2;

(5) Appendix A, Method 7E for the concentrations of NO_x and O_2, or equivalent methods;

(6) Appendix A, Method 8 or a modified Method 8 for H_2SO_4;

(7) Appendix A, Method 9 for opacity, as provided in 40 CFR § 60.11(b);

(8) Appendix A, Method 10 for the concentration of CO;

(9) Appendix A, Method 19, for applicable calculation methods;

(10) Appendix A, Method 25A, modified to exclude methane and ethane, for the concentration of VOC (to measure total carbon as propane);

(11) Appendix A, Method 26 or 26A for HCl and HF;

(12) EPA Conditional Test Method 27 (CTM-027), for NH_3;

(13) Appendix A, Method 29 for the metals listed in Attachment A;

(14) Appendix M, Methods 201A and 202, or Appendix A, Reference Method 5, modified to include back-half organic condensables, for the concentration of PM less than 10 microns in diameter, PM_{10}. For inorganic condensables, a parallel controlled condensation method (NCASI Method 8A) shall be used. (Any method, procedures, or apparatus not identified in the CFR must be approved by the TCEQ and EPA prior to use);

(15) Appendix M, Methods 201A or Appendix A, Reference Method 5, for the filterable concentration of PM less than 10 microns in diameter, PM_{10} (front-half catch); and

(16) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (also known as the Ontario Hydro Method), Appendix A, Method 30A or 30B, or other approved EPA methods.

B. Any deviations from the procedures in A. must be approved by the Executive Director of the TCEQ or his designated representative prior to sampling.

C. The TCEQ Corpus Christi Regional Office shall be given notice as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

(1) The notice shall include:

(a) Date for pretest meeting.
(b) Date sampling will occur.
(c) Name of firm conducting sampling.
(d) Type of sampling equipment to be used.
(e) Method or procedure to be used in sampling.
(f) Projected date of commencement of the 30-day rolling average initial performance tests for SO_2 and NO_x, in accordance with 40 CFR § 60.45b(c) and Special Condition No. 11A.

(2) The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to

review the format procedures for submitting the test reports. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in this permit and 40 CFR Part 60, Subpart Db.

(3) Prior to the pretest meeting, a written proposed description of any deviation from sampling procedures specified in permit conditions or TCEQ, EPA or ASTM sampling procedures shall be made available to the TCEQ. The TCEQ Corpus Christi Regional Director shall approve or disapprove of any deviation from specified sampling procedures.

D. Information in the test report shall include the following data for each test run:

(1) hourly petroleum coke firing rate (in tons);

(2) average petroleum coke Btu (HHV)/lb as-received and dry weight;

(3) average steam production rate (in millions of pounds per hour) or average generator output (in MW);

(4) daily sulfur content and heat content of the fuel measured in accordance with EPA Reference Method 19 to show compliance with 40 CFR Part 60, Subpart Db;

(5) control device operating rates, including SNCR reagent injection and solids injection rates (limestone, lime, and activated carbon);

(6) emissions in the units of the limits of this permit, lb/hr and lb/MMBtu, and three-hour or 30-day average, as appropriate; and

(7) any additional records deemed necessary during the stack sampling pre-test meeting.

E. Two copies of all final sampling reports shall be forwarded to the TCEQ within 60 days after sampling is completed. Sampling reports shall comply with the attached conditions of Chapter 14 of the TCEQ <u>Sampling Procedures Manual</u>. The reports shall be distributed as follows:

One copy to the TCEQ Corpus Christi Regional Office.

One copy to the TCEQ Austin Office of Permitting and Registration,
Air Permits Division.

F. The deadlines established by this condition may be extended by the TCEQ Corpus Christi Regional Office for good cause shown.

CONTINUOUS DEMONSTRATION OF COMPLIANCE

30. The holder of this permit shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the concentrations of NO_x, CO, and SO_2 from EPNs CFB1, CFB2, CFB3, and CFB4. Diluents to be measured include O_2 or CO_2. The CEMS data shall be used to determine continuous compliance with the NO_x, CO, and SO_2 emission limitations in Special Condition No. 3 (NO_x and SO_2), Special Condition No. 11A, and the attached MAERT. Continuous compliance with the performance standards of Special Condition No. 11A shall commence on the first boiler operating day of the 30-day initial performance testing required by NSPS Subpart Db.

    A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B or an acceptable EPA alternative. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Permitting and Registration, Air Permits Division in Austin for requirements to be met.

    B. The holder of this permit shall assure that the CEMS meets the applicable quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1, or an acceptable EPA alternative. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3, any CEMS downtime, and all cylinder gas audit exceedances of ±15 percent accuracy shall be reported semiannually to the TCEQ Corpus Christi Regional Director; necessary corrective action shall be taken on a timely basis. Supplemental stack concentration measurements may be required at the discretion of the TCEQ Corpus Christi Regional Director.

    C. The monitoring data shall be reduced to hourly average concentrations at least once every day, using normally a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emissions rate in pounds per hour at least once every day. Pound per hour data shall be summed on a monthly basis to tons per rolling 12 months and used to determine compliance with the annual emissions limits of this permit. If the CEMS malfunctions, then the recorded concentrations may be reduced to units of the permit allowable as soon as practicable after the CEMS resumes normal operation.

D. The TCEQ Corpus Christi Regional Office shall be notified at least 30 days prior to any required relative accuracy test audits in order to provide it the opportunity to observe the testing.

E. If applicable, each CEMS will be required to meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 75, Appendix A and B, as an acceptable alternative to paragraph A. of this condition.

F. Each CEMS shall be operational during 95 percent of the operating hours of the CFB Boiler, exclusive of the time required for zero and span checks. If this operational criterion is not met for a calendar quarter, the holder of this permit shall develop and implement a monitor quality improvement plan within the following calendar quarter. The plan should address the downtime issues to improve availability and reliability. The plan should provide additional assurance of compliance including record keeping of appropriate SNCR reagent and solids flow rates for monitor downtime periods.

31. The holder of this permit shall install, calibrate, operate, and maintain a continuous opacity monitoring system (COMS) to measure and record the opacity of emissions from EPNs CFB1, CFB2, CFB3, and CFB4. The COMS data shall be used to determine continuous compliance with the opacity emission limitations in Special Condition Nos. 3 and 10.

A. The COMS shall satisfy all of the Federal NSPS requirements for COMS as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS-1). In order to demonstrate compliance with PS-1, the COMS shall meet the manufacturer's design and performance specifications, and undergo performance evaluation testing as outlined in 40 CFR Subpart A , § 60.13. The TCEQ Corpus Christi Regional Director shall be notified 30 days prior to the certification.

B. The COMS shall be zeroed and spanned daily as specified in 40 CFR § 60.13. Corrective action shall be taken when the 24-hour span drift exceeds two times the amounts specified in PS-1, or as specified by the TCEQ if not specified in PS-1.

C. If the EPA promulgates a quality assurance, quality control standard for the COMS, a Quality Assurance Plan (QAP) shall be prepared in accordance with the EPA standard for the COMS and adhered to, within six months after promulgation. The QAP shall be maintained to reflect changes to component technology. At the request of the TCEQ Corpus Christi Regional Director, the holder of this permit shall submit documentation demonstrating compliance with these standards.

D. The data shall be reduced to six-minute opacity averages, using a minimum of 36 equally-spaced data points from each six-minute period, as specified in 40 CFR § 60.13.

E. The COMS shall be operational during 95 percent of the operating hours of the CFB Boiler, exclusive of the time required for zero and span checks. If this operational criteria is not met for a calendar quarter, the holder of this permit shall develop and implement a monitor quality improvement plan within the following calendar quarter. The plan should address the downtime issues to improve availability and reliability. The plan should provide additional assurance of compliance including EPA Reference Method 9 support during daytime monitor downtime periods and parametric support for nighttime monitor downtime periods.

F. Recertification, if required, shall be based on the requirements of 40 CFR Part 60, Appendix B, PS-1 in effect at the time of initial certification.

32. The holder of this permit shall install, calibrate, operate, and maintain CEMS to measure and record the concentration of NH_3 from EPNs CFB1, CFB2, CFB3, and CFB4. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 11A. The CEMS data shall be used to determine continuous compliance with the NH_3 performance specifications in Special Condition No. 11A and the MAERT. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Corpus Christi Regional Office, with consultation between the Regional Office and the TCEQ Air Permits Division.

33. The holder of this permit shall install, calibrate, operate, and maintain CEMS or sorbent trap monitoring system to measure and record the concentration of mercury from EPNs CFB1, CFB2, CFB3, and CFB4, as described in 40 CFR Parts 60 and 75 (the rule versions in effect immediately prior to February 8, 2008 vacatur of Clean Air Mercury Rule). The CEMS data shall be used to demonstrate continuous compliance with the emission limitations of Special Condition No. 11A and the MAERT.

34. Each CEMS shall be operational on a rolling 12-month average for at least 95 percent of the corresponding operating hours of the CFB boiler it is designed to monitor (excluding time required for zero and span). If any CEMS fails to meet the performance standards specified in this permit, it shall be repaired or replaced as soon as reasonably possible.

35. The as-fired petroleum coke shall be sampled at least once per calendar quarter and analyzed for sulfur, metals, and HHV, to demonstrate on-going compliance after the initial

demonstration of compliance with the sulfur content limit of Special Condition No. 8, the non-mercury metal performance standards identified in Attachment A of this permit, and the emission rates for lead in the MAERT. The analyses shall be obtained from a NELAC (National Environmental Laboratory Accreditation Conference) accredited laboratory under the Texas Laboratory Accreditation Program.

36. The holder of this permit shall install, operate, and maintain bag leak detection systems (BLDS) to monitor the performance of the baghouses on CFB1, CFB2, CFB3, and CFB4. The BLDS must meet the specifications and be operated according to the procedures of 40 CFR § 60.48Da(o)(4).

37. After the initial demonstration of compliance, on-going stack sampling of EPNs CFB1, CFB2, CFB3, and CFB4 for H_2SO_4, HCl, HF, VOC, and total PM/PM_{10} shall be used to demonstrate ongoing compliance and shall meet the following specifications:

    A. Stack sampling shall be performed once annually during periods of normal operation, except as follows:

        (1) If the annual test does not establish compliance with a performance standard of Special Condition No. 11B, the holder of this permit must conduct additional tests (under similar operating rates and fuel charge rates as used in the initial test, or under scenarios reviewed and approved by the TCEQ Corpus Christi Regional Office) during the year to be averaged with the previous test(s) to demonstrate compliance with Special Condition No. 11B; or

        (2) if, after three years of stack sampling, the average of the three annual stack sampling results for a pollutant is less than 70 percent of the applicable performance standard identified in Special Condition No. 11B, then compliance stack sampling for such pollutant may be conducted once every three years.

    B. Sampling required in A. of this special condition shall demonstrate compliance with the performance standards of Special Condition No. 11B and the lb/hr emission limits of the MAERT applicable to normal operations.

    C. Sampling required in A. of this special condition shall be conducted in accordance with the methods, procedures, and notification protocol specified in Special Condition No. 29.

    D. Ongoing compliance with the H_2SO_4, HF, HCl, VOC, and PM/PM_{10} tons per year emission rates in the MAERT shall be demonstrated by calculating rolling 12-month annual emissions from emission factors (lb/MMBtu, HHV) obtained from the sampling required in (A.) of this condition and the monthly total heat input (MMBtu, HHV) from petroleum coke.

38. Compliance with the following emission rates in the MAERT, applicable to periods of planned start-up and shutdown, shall be demonstrated as follows:

A. Compliance with the lead, PM and PM_{10} (front half and total) emission rates in the MAERT applicable during start-up and shutdown shall be demonstrated if the recorded pressure drop across the baghouse meets manufacturer guidelines for proper operation during start-up and shutdown.

B. Compliance with the VOC emission rate in the MAERT applicable during start-up and shutdown shall be demonstrated if the CO emissions during start-up and shutdown are in compliance with the CO emission rate in the MAERT for start-up and shutdown.

C. Compliance with the H_2SO_4, HF, and HCl emission rates in the MAERT for start-up and shutdown shall be demonstrated if the SO_2 emissions during start-up and shutdown are in compliance with the SO_2 emission rate in the MAERT for start-up and shutdown.

39. Following the initial demonstration of compliance, ongoing compliance with the emission limits for the sources and emission limitations listed in this condition shall be through source operation in accordance with manufacturer's specifications, or in accordance with written procedures that are shown to maintain operating conditions necessary for emission compliance. The Executive Director of the TCEQ or his designated representative may also require direct measurement of emissions using the sampling methods and procedures specified in Special Condition No. 29 to establish compliance with the limitations, in which case the sampled emission rate will be used to determine compliance.

A. The Auxiliary Boilers (EPNs AUX-BOIL1 and AUX-BOIL2) emission limitations of Special Condition No. 16A and 16B and the MAERT.

B. The Propane Vaporizers (EPNs PROP-VAP1 and PROP-VAP2) emission limitations of Special Condition No. 17A and the MAERT.

C. The Diesel Engines (EPNs ENG-EG1, ENG-EG2, ENG-FWMAIN, ENG-FWB1, ENG-FWB2, ENG-FWB3, ENG-FWB4, ENG-BFWP1, ENG-BFWP2, ENG-BFWP3, and ENG-BFWP4) emission limitations in the MAERT.

40. Following the initial demonstration of compliance, ongoing compliance with the emission rates in the MAERT for the Cooling Towers (EPNs CTWR1 and CTWR2) will be based on

annual inspections of modules, and repair as necessary to maintain drift eliminator structural integrity and minimize bypassing of flow around drift eliminators.

41. Following the initial demonstration of compliance, ongoing compliance with the emission rates in the MAERT for the petroleum coke, ash, limestone, lime, sand, and carbon material handling baghouses will be demonstrated by annual opacity testing using Reference Method 9 for those EPNs listed in Special Condition Nos. 26 and 27. The Executive Director of the TCEQ or his designated representative may also require sampling conducted in accordance with the methods and procedures specified in Special Condition No. 29 to directly measure the lb/hr emission rate, in which case the sampled lb/hr emission rate will be used to determine compliance with the applicable emission rate in the MAERT.

42. Compliance with the emission rates in the MAERT for the Fuel Storage Tanks (EPNs TNK-FWMAIN, TNK-EG1, TNK-EG2, TNK-FWB1, TNK-FWB2, TNK-FWB3, TNK-FWB4, TNK-BFWP1, TNK-BFWP2, TNK-BFWP3, and TNK-BFWP4) will be demonstrated by compliance with Special Condition No. 22.

CASE-BY-CASE MACT

43. This case-by-case MACT permit, Permit No. HAP48, establishes federally enforceable MACT emission limits for CO (CO is a surrogate of organic HAPs) and filterable PM (filterable PM is a surrogate for non-mercury HAP metals) for the natural gas-fired Auxiliary Boilers (identified as EPNs AUX-BOIL1 and AUX-BOIL2) and the Propane Vaporizers (identified as EPNs PROP-VAP1 and PROP-VAP2). These facilities shall comply with all applicable requirements of 30 TAC Chapter 113, 30 TAC Chapter 116, and the EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63, promulgated for:

    A. Applicable General Provisions, Subpart A; and

    B. Federal Clean Air Act Section 112(g), case-by-case MACT determination.

RECORDKEEPING REQUIREMENTS

44. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, the EPA, or any air pollution control agency with jurisdiction.

    A. A copy of this permit.

B. Permit application dated May 19, 2008 and subsequent representations submitted to the TCEQ prior to permit issuance.

C. A complete copy of the testing reports and records of the initial air emissions performance testing completed pursuant to the Initial Demonstration of Compliance.

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

E. The written SS plan required by Special Condition No. 14.A.

45. The following records shall be kept for a minimum of five years after collection and shall be made immediately available upon request to representatives of the TCEQ, the EPA, or any local air pollution control program having jurisdiction. Records shall be legible and maintained in an orderly manner. The following records shall be maintained:

A. Continuous emission monitoring data for opacity, SO_2, NO_x, CO, Hg, NH_3, and diluent gases, O_2 or CO_2, from CEMS to demonstrate compliance with the emission rates listed in the MAERT and performance standards listed in this permit for pollutants that are monitored by CEMS or COMS. Data retention at intervals less than one hour is not required. Records must identify the times when emissions data have been excluded from the calculation of performance standards because of start-up, shutdown, maintenance, and malfunction along with the justification for excluding data. Records should also identify factors used in calculations that are used to demonstrate compliance with emissions limits and performance standards.

B. Files of all CEMS or COMS quality assurance measures including calibration checks, adjustments and maintenance performed on these systems.

C. Written, certified petroleum coke analysis, to include HHV, for all petroleum coke received from each petroleum coke supplier, to show compliance of the as-fired fuel with the sulfur and trace metal concentration limits of this permit, and written certified analysis provided by natural gas and diesel fuel suppliers to show compliance with the sulfur content limitations of this permit.

D. Average petroleum coke feed rate to the CFB Boilers in pounds per hour and the corresponding average heat input (HHV) in MMBtu/hr, based upon an average over each calendar month.

E. Ammonia, limestone, and lime feed rates established during a successful initial performance test to fulfill the requirements of Special Condition Nos. 12 and 13.

F. Hours of operation of the emergency generators, fire water pumps, boiler feed water pumps, propane vaporizers, and auxiliary boilers to show compliance with the hourly operating limitations of this permit.

G. The amount of fuel received for storage in EPNs TNK-FWMAIN, TNK-EG1, TNK-EG2, TNK-FWB1, TNK-FWB2, TNK-FWB3, TNK-FWB4, TNK-BFWP1, TNK-BFWP2, TNK-BFWP3, and TNK-BFWP4 and the consecutive 12-month total of fuel received for each storage tank to show compliance with the throughput requirements of this permit.

H. Records of cleaning and maintenance performed on abatement equipment, including records of replacement maintenance performed on baghouses. A log should be kept with descriptions of the activity performed, any parts or subassemblies replaced, and the time period over which the cleaning or maintenance was performed.

I. Records required to show compliance with 40 CFR Part 60, Subparts Db and III, including daily average SO_2 removal efficiency, baghouse performance monitoring, and records of required reporting.

J. Records of all venting of the anhydrous ammonia storage tanks to show compliance with Special Condition No. 20D.

K. Records of personnel training related to anhydrous ammonia injection operations and emergency response planning, including names of trainers and trainees, dates of training, and material covered, to show compliance with Special Condition No. 20F.

L. Records of audio, olfactory, and visual checks for ammonia leaks and repairs to show compliance with Special Condition No. 21.

M. Records, including dates performed, of road maintenance for dust control to show compliance with Special Condition No. 23.

<u>REPORTING</u>

46. The holder of this permit shall submit to the TCEQ Corpus Christi Regional Office quarterly or semiannual reports of excess emissions and monitoring systems performance, as described in 40 CFR § 60.7(c), for each emission unit which is required to be continuously monitored pursuant to 40 CFR Part 60. In addition, these reports shall identify:

    A. Any emissions of continuously monitored CO, ammonia, and mercury in excess of any of the limits of this permit and monitoring systems performance, following the format of 40 CFR § 60.7(c);

    B. The pollutant, emission rates, and test dates of any stack emission tests conducted during the reporting period which is in excess of any of the limits of this permit.

47. Within one year after initial start-up of the first CFB, the holder of this permit shall submit a copy of the SS plan identified in Special Condition No. 14.A. to the TCEQ Air Permits Division in Austin and the U.S. EPA Region 6 Air Permits Section, 1445 Ross Avenue, Dallas, Texas 75202-2733.

AS-BUILT INFORMATION

48. The holder of this permit shall submit to the TCEQ Corpus Christi Regional Office and the TCEQ Air Permits Division change pages to the permit application reflective of the final plans and engineering specifications on the CFB Boilers, auxiliary boilers, emergency engines, and other sources, including their respective control equipment, no later than 30 days before initial start-up of the CFB Boilers. This information shall include:

    A. All TCEQ Tables in the permit application, updated with manufacturer and other specified data.

    B. Revised plot plans and equipment drawings as required to reflect the constructed facility.

    C. Identification of any maximum inputs of raw materials for the as-built facility, and any diesel fuel sulfur or engine manufacturer's emission specification that is lower than the values represented in the permit application and used for calculating or establishing emissions. Accompanying this information shall be a request for permit alteration. The TCEQ may alter the permit special conditions and MAERT to reflect any such reduction in emissions. Increases in allowable emission rates shall require authorization before construction begins.

OPTIMIZATION STUDIES

49. Within 60 days after completing the first annual compliance sampling required by Special Condition No. 37, the holder of this permit shall submit a request to adjust the performance standards for the control of H_2SO_4, HCl, HF, Hg, VOC, and front half and total PM/PM_{10} identified in Special Condition No. 11B to reflect the results of the sampling of these compounds conducted to that date, with appropriate consideration given for data variability. The adjustment on a pollutant-by-pollutant basis to the performance standard for the control of H_2SO_4, HCl, HF, Hg, VOC, or front half and total PM/PM_{10} shall only be required if the average of the sampling for any such pollutant is 50 percent or less of the currently permitted value. At a minimum, this submittal shall include the Initial Demonstration of Compliance sampling required by this permit and the first annual compliance sampling required by Special Condition No. 37.

Dated__________________

Attachment A
Permit Numbers 85013 and PSD-TX-1138
Non-Mercury Metal Concentrations in Petroleum Coke
and Emission Performance Standards

Constituent	Maximum Concentration (ppmw)	Performance Standard (lb/MMBtu)
Arsenic	14.25	4.82E-05
Cadmium	3	1.01E-05
Beryllium	2.25	7.61E-06
Lead	18	6.09E-05
Chromium	98.13	3.32E-04
Copper	5.25	1.78E-05
Manganese	945	3.20E-03
Selenium	397.5	1.34E-03
Silicon	25.5	8.62E-05
Aluminum	69	2.33E-04
Iron	375	1.27E-03
Calcium	28.5	9.64E-05
Sodium	97.5	3.30E-04
Potassium	42	1.42E-04
Titanium	1.5	5.07E-06
Magnesium	9	3.04E-05
Nickel	880.5	2.98E-03
Vanadium	42,000	1.42E-02

Dated_________________

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Permit Numbers 85013, HAP48, and PSD-TX-1138

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

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates ** lb/hr**	**TPY***
CFB1 and 2	CFB Boiler 1	NO_X (4)	308	944
	3,080 MMBtu/hr	SO_2 (4)	714	1,160
	(Normal operations	SO_2 (start-up) (4)	4,910	--
	including planned	CO (4)	339	1,349
	start-ups/shutdowns)	VOC	15.4	67.5
		PM/PM_{10} (filterable)	33.9	148
		PM/PM_{10} (total)	77	337
		H_2SO_4	14	61
		H_2SO_4 (start-up)	316	--
		NH_3 (4)	16	35
		Hg (4)	0.0062	0.0077
		HCl	13.6	12
		HCl (start-up)	136	--
		HF	1.2	1.1
		HF (start-up)	12	--
		Pb	0.020	0.013

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Emission Point No. (1)	Source Name (2)	AIR CONTAMINANTS DATA Air Contaminant Name (3)	Emission Rates ** lb/hr	TPY*
CFB1 and 2	CFB Boiler 2	NO_X (4)	308	944
	3,080 MMBtu/hr	SO_2 (4)	714	1,160
	(Normal operations	SO_2 (start-up) (4)	4,910	--
	including planned	CO (4)	339	1,349
	start-ups/shutdowns)	VOC	15.4	67.5
		PM/PM_{10} (filterable)	33.9	148
		PM/PM_{10} (total)	77	337
		H_2SO_4	14	61
		H_2SO_4 (start-up)	316	--
		NH_3 (4)	16	35
		Hg (4)	0.0062	0.0077
		HCl	13.6	12
		HCl (start-up)	136	--
		HF	1.2	1.1
		HF (start-up)	12	--
		Pb	0.020	0.013
CFB3 and 4	CFB Boiler 3	NO_X (4)	308	944
	3,080 MMBtu/hr	SO_2 (4)	714	1,160
	(Normal operations	SO_2 (start-up) (4)	4,910	--
	including planned	CO (4)	339	1,349
	start-ups/shutdowns)	VOC	15.4	67.5
		PM/PM_{10} (filterable)	33.9	148
		PM/PM_{10} (total)	77	337
		H_2SO_4	14	61
		H_2SO_4 (start-up)	316	--
		NH_3 (4)	16	35
		Hg (4)	0.0062	0.0077
		HCl	13.6	12
		HCl (start-up)	136	--
		HF	1.2	1.1
		HF (start-up)	12	--
		Pb	0.020	0.013

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Emission Point No. (1)	Source Name (2)	AIR CONTAMINANTS DATA Air Contaminant Name (3)	Emission Rates ** lb/hr	TPY*
CFB3 and 4	CFB Boiler 4	NO_X (4)	308	944
	3,080 MMBtu/hr	SO_2 (4)	714	1,160
	(Normal operations	SO_2 (start-up) (4)	4,910	--
	including planned	CO (4)	339	1,349
	start-ups/shutdowns)	VOC	15.4	67.5
		PM/PM_{10} (filterable)	33.9	148
		PM/PM_{10} (total)	77	337
		H_2SO_4	14	61
		H_2SO_4 (start-up)	316	--
		NH_3 (4)	16	35
		Hg (4)	0.0062	0.0077
		HCl	13.6	12
		HCl (start-up)	136	--
		HF	1.2	1.1
		HF (start-up)	12	--
		Pb	0.020	0.013
AUX-BOIL1	Auxiliary Boiler	NO_X (5)	6.3	7.9
	for Units 1 and 2	NO_X (start-up) (6)	18	--
	180 MMBtu/hr	CO (5)	7.5	9.4
	(Normal operations	CO (start-up) (6)	75	--
	including planned	PM_{10}	1.4	1.7
	start-ups/shutdowns)	VOC	1.0	1.3
		SO_2	0.12	0.15
AUX-BOIL2	Auxiliary Boiler	NO_X (5)	6.3	7.9
	for Units 3 and 4	NO_X (start-up) (6)	18	--
	180 MMBtu/hr	CO (5)	7.5	9.4
	(Normal operations	CO (start-up) (6)	75	--
	including planned	PM_{10}	1.4	1.7
	start-ups/shutdowns)	VOC	1.0	1.3
		SO_2	0.12	0.15

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

			AIR CONTAMINANTS DATA	
			Emission Rates **	
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**lb/hr**	**TPY***
PROP-VAP1	Propane Vaporizer for Units 1 and 2 16 MMBtu/hr	NO_X	1.6	2.0
		CO	1.3	1.6
		PM_{10}	0.12	0.15
		VOC	0.14	0.17
		SO_2	0.04	0.05
PROP-VAP2	Propane Vaporizer for Units 3 and 4 16 MMBtu/hr	NO_X	1.6	2.0
		CO	1.3	1.6
		PM_{10}	0.12	0.15
		VOC	0.14	0.17
		SO_2	0.04	0.05
SILO-FA1	Fly Ash Silo No. 1	PM/PM_{10}	0.31	1.4
SILO-FA2	Fly Ash Silo No. 2	PM/PM_{10}	0.31	1.4
SILO-FA3	Fly Ash Silo No. 3	PM/PM_{10}	0.31	1.4
SILO-FA4	Fly Ash Silo No. 4	PM/PM_{10}	0.31	1.4
SILO-BA1	Bed Ash Silo No. 1	PM/PM_{10}	0.24	1.0
SILO-BA2	Bed Ash Silo No. 2	PM/PM_{10}	0.24	1.0
SILO-BA3	Bed Ash Silo No. 3	PM/PM_{10}	0.24	1.0
SILO-BA4	Bed Ash Silo No. 4	PM/PM_{10}	0.24	1.0
SILO-COKE1	Coke Silo No. 1	PM/PM_{10}	1.4	--
SILO-COKE2	Coke Silo No. 2	PM/PM_{10}	1.4	--
SILO-COKE1, SILO-COKE2	Coke Silos Nos 1 and 2 (7)	PM/PM_{10}	--	6.2

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	AIR CONTAMINANTS DATA Emission Rates ** lb/hr	TPY*
SILO-COKE3	Coke Silo No. 3	PM/PM_{10}	1.4	--
SILO-COKE4	Coke Silo No. 4	PM/PM_{10}	1.4	--
SILO-COKE3, SILO-COKE4	Coke Silos Nos. 3 and 4 (7)	PM/PM_{10}	--	6.2
SILO-COKE5	Coke Silo No. 5	PM/PM_{10}	1.4	--
SILO-COKE6	Coke Silo No. 6	PM/PM_{10}	1.4	--
SILO-COKE5, SILO-COKE6	Coke Silos Nos. 5 and 6 (7)	PM/PM_{10}	--	6.2
SILO-COKE7	Coke Silo No. 7	PM/PM_{10}	1.4	--
SILO-COKE8	Coke Silo No. 8	PM/PM_{10}	1.4	--
SILO-COKE7, SILO-COKE8	Coke Silos Nos. 7 and 8 (7)	PM/PM_{10}	--	6.2
SILO-LMST1	Limestone Bunker No. 1	PM/PM_{10}	0.07	0.10
SILO-LMST2	Limestone Bunker No. 2	PM/PM_{10}	0.07	0.10
SILO-LMST3	Limestone Bunker No. 3	PM/PM_{10}	0.07	0.10
SILO-LMST4	Limestone Bunker No. 4	PM/PM_{10}	0.07	0.10
SILO-ACI1	Carbon Silo for ACI No. 1	PM/PM_{10}	0.14	0.21
SILO-ACI2	Carbon Silo for ACI No. 2	PM/PM_{10}	0.14	0.21
SILO-ACI3	Carbon Silo for ACI No. 3	PM/PM_{10}	0.14	0.21

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

		AIR CONTAMINANTS DATA		
			Emission Rates **	
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**lb/hr**	**TPY***
SILO-ACI4	Carbon Silo for ACI No. 4	PM/PM_{10}	0.14	0.21
SILO-LIME1	Lime Silo No. 1	PM/PM_{10}	0.14	0.21
SILO-LIME2	Lime Silo No. 2	PM/PM_{10}	0.14	0.21
SILO-LIME3	Lime Silo No. 3	PM/PM_{10}	0.14	0.21
SILO-LIME4	Lime Silo No. 4	PM/PM_{10}	0.14	0.21
SILO-LIME5	Lime Silo No. 5	PM/PM_{10}	0.14	0.21
SILO-LIME6	Lime Silo No. 6	PM/PM_{10}	0.14	0.21
SILO-LIME7	Lime Silo No. 7	PM/PM_{10}	0.14	0.21
SILO-LIME8	Lime Silo No. 8	PM/PM_{10}	0.14	0.21
BIN-SAND1	Unit 1 Sand Day Bin	PM/PM_{10}	0.043	0.064
BIN-SAND2	Unit 2 Sand Day Bin	PM/PM_{10}	0.043	0.064
BIN-SAND3	Unit 3 Sand Day Bin	PM/PM_{10}	0.043	0.064
BIN-SAND4	Unit 4 Sand Day Bin	PM/PM_{10}	0.043	0.064
WT-LIME	Water Treatment Lime Silo	PM/PM_{10}	0.086	0.13
WT-SODA	Water Treatment Soda Ash Silo	PM/PM_{10}	0.086	0.13
CTWR1	Cooling Tower No. 1	PM	12.0	52.6
		PM_{10}	0.29	1.29

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

		AIR CONTAMINANTS DATA		
			Emission Rates **	
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**lb/hr**	**TPY***
CTWR2	Cooling Tower No. 2	PM	12.0	52.6
		PM_{10}	0.29	1.29
ENG-EG1	Diesel Engine Emergency Generator 1 1,600 kW	NO_X	24.3	6.1
		CO	13.3	3.3
		PM_{10}	0.61	0.15
		VOC	1.5	0.37
		SO_2	0.93	0.23
		H_2SO_4	0.070	0.018
ENG-EG2	Diesel Engine Emergency Generator 2 1,600 kW	NO_X	24.30	6.10
		CO	13.30	3.30
		PM_{10}	0.61	0.15
		VOC	1.46	0.37
		SO_2	0.93	0.23
		H_2SO_4	0.070	0.018
ENG-FWMAIN	Main Fire Water Pump Diesel Engine 360-horsepower	NO_X	2.38	0.60
		CO	2.06	0.52
		PM_{10}	0.12	0.03
		VOC	0.89	0.22
		SO_2	0.14	0.04
		H_2SO_4	0.01	0.003
ENG-FWBP1	Fire Water Booster Pump 1 Diesel Engine 100-horsepower	NO_X	0.66	0.17
		CO	0.57	0.14
		PM_{10}	0.03	0.01
		VOC	0.25	0.06
		SO_2	0.04	0.01
		H_2SO_4	0.003	0.001

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	AIR CONTAMINANTS DATA Emission Rates ** lb/hr	TPY*
ENG-FWBP2	Fire Water Booster Pump 2 Diesel Engine 100-horsepower	NO_X	0.66	0.17
		CO	0.57	0.14
		PM_{10}	0.03	0.01
		VOC	0.25	0.06
		SO_2	0.04	0.01
		H_2SO_4	0.003	0.001
ENG-FWBP3	Fire Water Booster Pump 3 Diesel Engine 100-horsepower	NO_X	0.66	0.17
		CO	0.57	0.14
		PM_{10}	0.03	0.01
		VOC	0.25	0.06
		SO_2	0.04	0.01
		H_2SO_4	0.003	0.001
ENG-FWBP4	Fire Water Booster Pump 4 Diesel Engine 100 horsepower	NO_X	0.66	0.17
		CO	0.57	0.14
		PM_{10}	0.03	0.01
		VOC	0.25	0.06
		SO_2	0.04	0.01
		H_2SO_4	0.003	0.001
ENG-BFWP1	Boiler Feed Water (BFW) Pump 1 Diesel Engine 2,000 horsepower	NO_X	13.23	3.31
		CO	11.46	2.87
		PM_{10}	0.66	0.17
		VOC	4.94	1.24
		SO_2	0.80	0.20
		H_2SO_4	0.06	0.016
ENG-BFWP2	BFW Pump 2 Diesel Engine 2,000 horsepower	NO_X	13.23	3.31
		CO	11.46	2.87
		PM_{10}	0.66	0.17
		VOC	4.94	1.24
		SO_2	0.80	0.20
		H_2SO_4	0.06	0.016

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	AIR CONTAMINANTS DATA Emission Rates ** lb/hr	TPY*
ENG-BFWP3	BFW Pump 3 Diesel Engine 2,000 horsepower	NO_X	13.23	3.31
		CO	11.46	2.87
		PM_{10}	0.66	0.17
		VOC	4.94	1.24
		SO_2	0.80	0.20
		H_2SO_4	0.06	0.016
ENG-BFWP4	BFW Pump 4 Diesel Engine 2,000-horsepower	NO_X	13.23	3.31
		CO	11.46	2.87
		PM_{10}	0.66	0.17
		VOC	4.94	1.24
		SO_2	0.80	0.20
		H_2SO_4	0.06	0.016
TNK-FWMAIN	Diesel Fuel Tank for Main Fire Water Pump Engine	VOC	0.0104	0.0002
TNK-EG1	Diesel Fuel Tank for Emergency Generator 1	VOC	0.0104	0.0001
TNK-EG2	Diesel Fuel Tank for Emergency Generator 2	VOC	0.0104	0.0001
TNK-FWB1	Diesel Fuel Tank for Fire Water Booster Pump 1 Engine	VOC	0.0104	0.0003
TNK-FWB2	Diesel Fuel Tank for Fire Water Booster Pump 2 Engine	VOC	0.0104	0.0003
TNK-FWB3	Diesel Fuel Tank for Fire Water Booster Pump 3 Engine	VOC	0.0104	0.0003

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

		AIR CONTAMINANTS DATA		
			Emission Rates **	
Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**lb/hr**	**TPY***
TNK-FWB4	Diesel Fuel Tank for Fire Water Booster Pump 4 Engine	VOC	0.0104	0.0003
TNK-BFWP1	Diesel Fuel Tank for BFW Pump 1 Engine	VOC	0.0104	0.0004
TNK-BFWP2	Diesel Fuel Tank for BFW Pump 2 Engine	VOC	0.0104	0.0004
TNK-BFWP3	Diesel Fuel Tank for BFW Pump 3 Engine	VOC	0.0104	0.0004
TNK-BFWP4	Diesel Fuel Tank for BFW Pump 4 Engine	VOC	0.0104	0.0004
TNK-ACID	Acid Storage Tank	H_2SO_4	0.16	0.0032
TNK-BASE	Base Storage Tank	NaOH	0.069	0.0014
FUG-NH3A	Fugitives: Ammonia	NH_3 (8)	0.10	0.45
FUG-NH3B	Fugitives: Ammonia	NH_3 (8)	0.10	0.45
FUG-NG	Fugitives: Natural Gas	VOC (8)	0.19	0.84
FUG-PROP1	Fugitives: Propane	VOC (8)	0.41	1.80
FUG-PROP2	Fugitives: Propane	VOC (8)	0.41	1.80

EMISSION SOURCES - MAXIMUM ALLOWABLE EMISSION RATES

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources use area name or fugitive source name.
(3) NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
PM - particulate matter, suspended in the atmosphere, including PM_{10}.
PM_{10} - particulate matter equal to or less than 10 microns in diameter. Where PM is not listed, it shall be assumed that no PM greater than 10 microns is emitted.
NH_3 - ammonia
CO - carbon monoxide
H_2SO_4 - sulfuric acid mist
Pb - lead
HCl - hydrogen chloride
HF - hydrogen fluoride
Hg - mercury
(4) Compliance with the hourly emission limit is based on a three-hour block average of the CEMS data.
(5) Hourly limit applies when auxiliary boiler is operating at or above 25 percent load.
(6) Hourly limit applies when auxiliary boiler is operating below 25 percent load, and during start-up and shutdown.
(7) Only one of the two paired coke silo fabric filters operates at the same time.
(8) Fugitives emission rate is an estimate and compliance is demonstrated by meeting the requirements of the applicable special conditions and permit application representations.

* For combustion sources and storage tanks, compliance with annual emission limits is based on a rolling 12-month period. For material handling sources, compliance with annual emission limits is based on applicable Special Conditions and permit application representations.

** Except as otherwise specified in special conditions, emission rates are based on and the facilities are limited by the following maximum operating schedule:

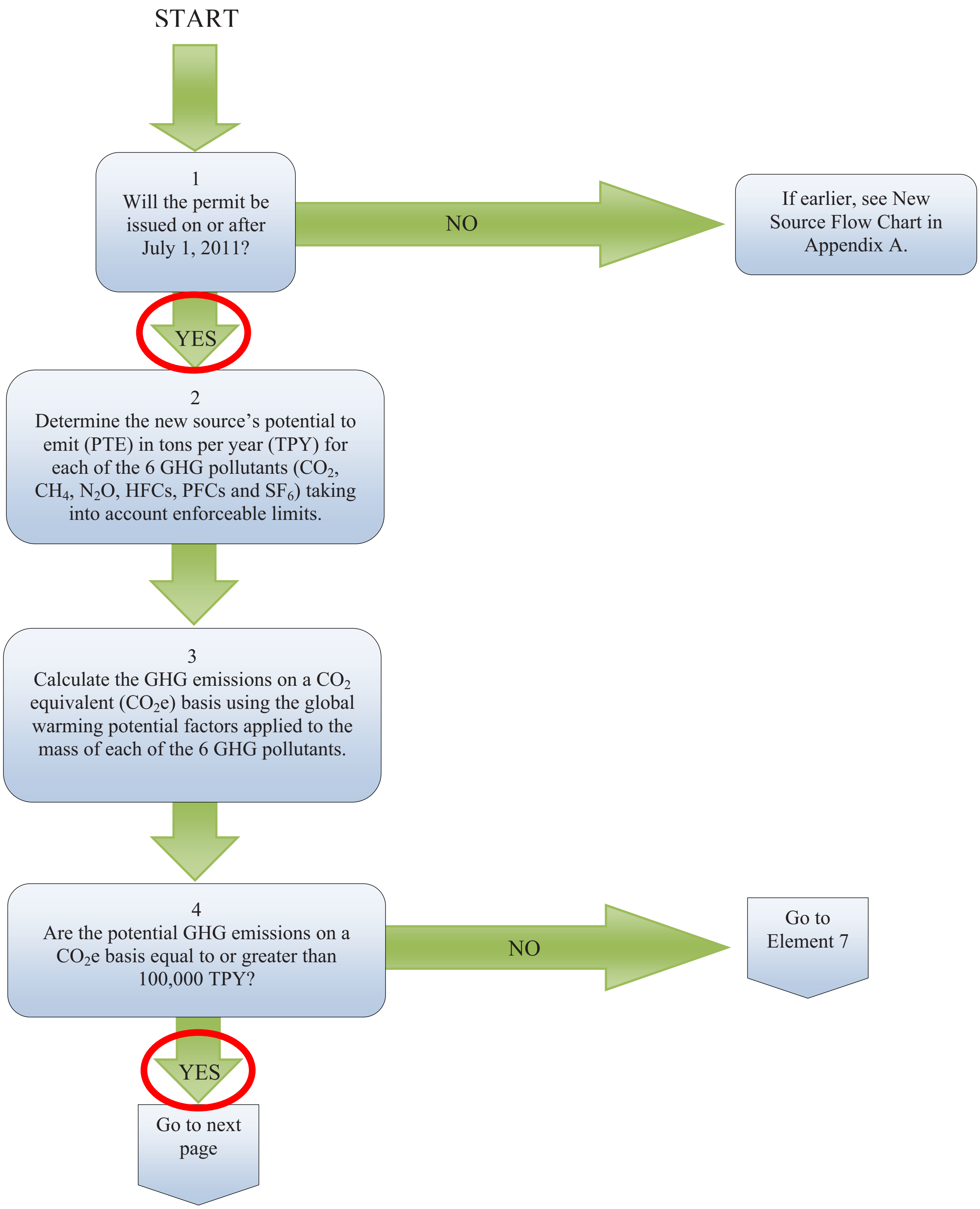
Hrs/day 24 Days/week 7 Weeks/year 52 or Hrs/yr 8,760

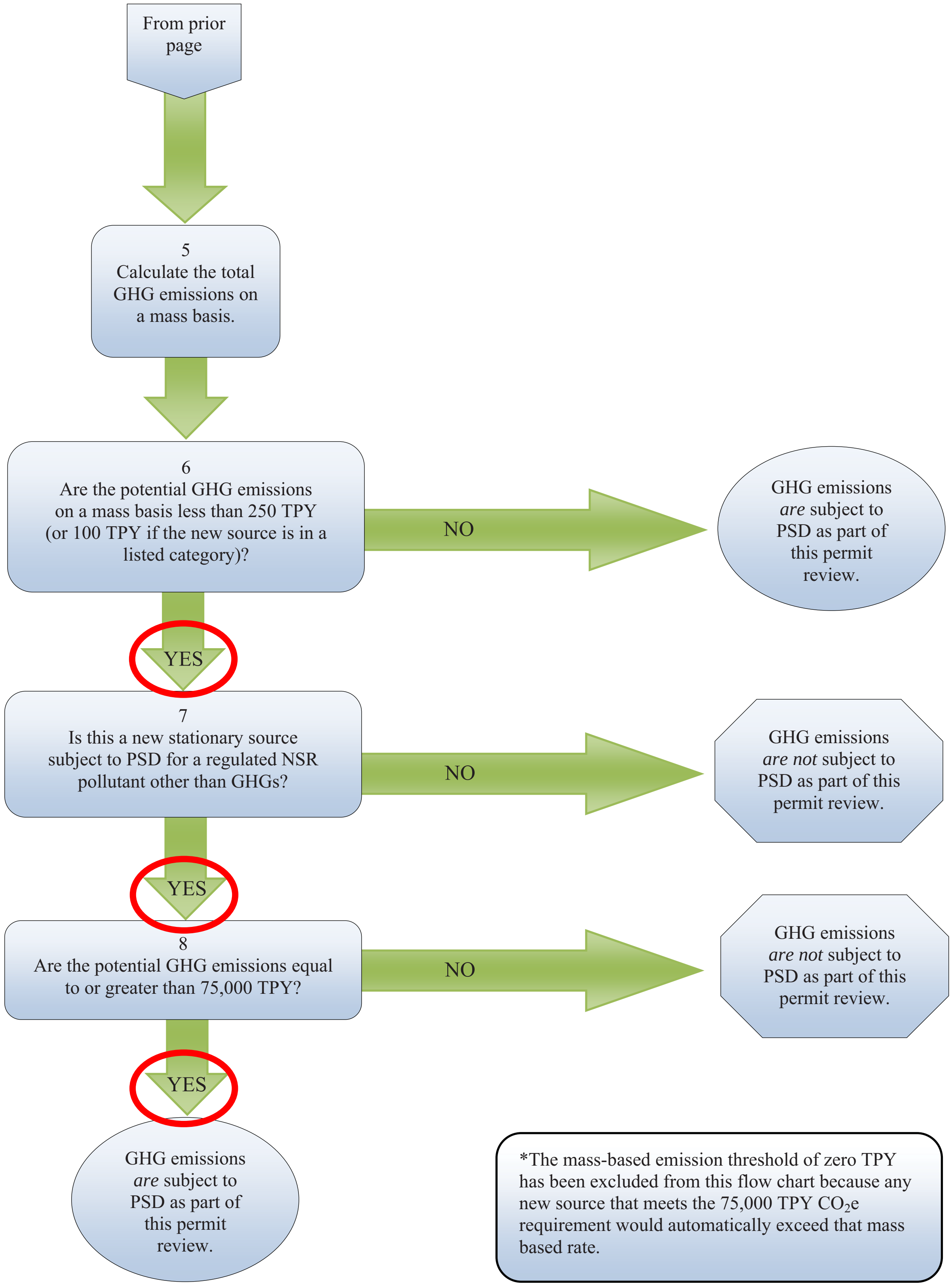
Dated____________________

APPENDIX B

GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES

Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)




From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.