ENERGY • WATER • COMMUNITY SERVICES

March 15, 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
Lower Colorado River Authority
Thomas C. Ferguson Power Plant
Horseshoe Bay, Llano County, Texas

Dear Mr. Robinson:

The Lower Colorado River Authority (LCRA) is hereby submitting the attached application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for the construction of a new combined cycle plant consisting of two combustion turbine units at the Thomas C. Ferguson Power Plant in Llano County, Texas. The project proposes to replace an existing 37 year-old 440 megawatt electric generating boiler with a new highly efficient natural gas-fired combined cycle power plant with a generating capacity of 550–600 megawatts.

The attached application includes a copy of the Texas Commission on Environmental Quality (TCEQ) Form PI-1 - General Application for Air Preconstruction Permit and Amendments, which was submitted to the TCEQ on October 29, 2010, to authorize the state/PSD air permit for non-greenhouse gas emissions for the project. The U.S. Environmental Protection Agency's (EPA) document *PSD and Title V Permitting Guidance For Greenhouse Gases, Nov. 2010,* was utilized as a guide for preparation of the attached application.

LCRA's goal is to begin construction on the project in late 2011. Therefore, the timing of the EPA's review of the greenhouse gas application is a critical step in the project's schedule. Since preparing and reviewing PSD applications for greenhouse gas emissions is new for both permit writers and permit applicants, LCRA is committed to working closely with EPA Region 6 to have the application review completed as expeditiously as possible. LCRA will be contacting your staff soon after submittal of this application to arrange a meeting to review the application and answer any EPA questions.

The application is submitted to EPA under authority EPA has asserted through its Interim Final and Proposed Federal Implementation Plan (FIP) for the regulation of greenhouse gases. The State of Texas and other petitioners have challenged EPA's FIP, claiming that EPA's FIP action is unlawful. The case is currently pending in the United States Court of Appeals for the D.C. Circuit. LCRA takes no position on whether EPA's imposition of the challenged FIP is lawful, and its application is not an admission that the authority EPA asserts is consistent with the federal Clean Air Act."

Should you have any questions regarding this application, please contact LCRA's technical contact for this application, Mr. Joe Bentley, at joe.bentley@lcra.org or at (512) 473-3272.

Sincerely,

Michael McCluskey
Manager, Generation Resource Development

Attachment

cc: Mr. Steve Hagle, P.E., Director, Air Permits Division, TCEQ
Ms. Melanie Magee, EPA Region 6
Mr. Larry Moon, P.E., Zephyr Environmental Corporation

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR TWO COMBINED CYCLE ELECTRIC GENERATING UNITS AT THE THOMAS C FERGUSON POWER PLANT LLANO 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:
LOWER COLORADO RIVER AUTHORITY
P.O. BOX 220
AUSTIN, TEXAS 78767-0220

PREPARED BY:
ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

MARCH, 2011

3-15-2011
Zephyr Environmental Corporation
STATE OF TEXAS
LARRY A. MOON
69515
LICENSED
PROFESSIONAL ENGINEER
F-102

zephyr

TABLE OF CONTENTS

1.0 INTRODUCTION

On October 29, 2010, the Lower Colorado River Authority (LCRA) submitted an application for an air quality permit for the construction of two new combined cycle electric generating units at the Thomas C. Ferguson Power Plant in Llano County, Texas. The application was submitted to the Texas Commission on Environmental Quality (TCEQ) and a copy was submitted to the U.S. Environmental Protection Agency (EPA) Region 6. These new combined cycle units will replace the existing 440 megawatt (MW) steam boiler and turbine generator at Thomas C. Ferguson. The new units will consist of two natural gas fired combustion turbines, each exhausting to an unfired heat recovery steam generator (HRSG) to produce steam to drive a shared steam turbine. This configuration will result in a nominal plant electric generating capacity of 550–600 MW. Two models of combustion turbines are being considered for this site: the General Electric 7FA and the Siemens SGT6-5000F.

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule.[1] The rules require that between January 2, 2011, and June 30, 2011, only sources that are currently subject to PSD and Title V permitting are subject to permitting for GHGs (i.e., no sources would be subject to the Clean Air Act permitting due solely to GHG emissions). During this time, only GHG increases of 75,000 tons per year (tons/yr) or more are subject to a Best Available Control Technology (BACT) analysis of GHGs under the PSD program. There is no "grandfathering" of PSD applications in process as of January 2, 2011, (i.e., a BACT analysis is required for GHG emission increases greater than 75,000 tons/yr for any PSD permit issued after that date).

After July 1, 2011, new sources emitting more than 100,000 tons/yr of GHGs and modifications increasing GHG emissions more than 75,000 tons/yr at existing major sources are subject to PSD review, regardless of whether PSD was triggered for other pollutants. Facilities that emit at least 100,000 tons/yr are subject to Title V permitting requirements.

On December 23, 2010, EPA signed a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The LCRA project at the Thomas C. Ferguson Power Plant triggered PSD review for non-GHG regulated pollutants. Therefore, the project is subject to PSD review for GHG emissions since the project will increase GHG emissions by more than 75,000 tons/yr. Included in this application is a project scope description, GHG emissions calculations, GHG netting analysis, and a GHG Best Available Control Technology (BACT) analysis.

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[1] 75 FR 31514 (June 3, 2010).

[2] 75 FR 81874 (Dec. 29, 2010).

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

Update: The TCEQ **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued by the TCEQ and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to the TCEQ Web site at www.tceq.state.tx.us/permitting/central_registry/guidance.html.

I. APPLICANT INFORMATION				
A. Company or Other Legal Name: **Lower Colorado River Authority**				
Texas Secretary of State Charter/Registration Number (*if applicable*):				
B. Company Official Contact Name (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): **Kenneth W. Taylor**				
Title: **Power Production Manager**				
Mailing Address: **104 East State Hwy 71 Bypass**				
City: **LaGrange**		State: **TX**		ZIP Code: **78945**
Telephone No: **979-249-8377**	Fax No.: **512-498-1683**		E-mail Address: **ken.taylor@lcra.org**	
C. Technical Contact Name (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): **Joe Bentley**				
Title: **Environmental Program Manager**				
Company Name: **Lower Colorado River Authority**				
Mailing Address: **P.O. Box 220**				
City: **Austin**		State: **TX**		ZIP Code: **78767**
Telephone No.: **512-473-3272**	Fax No.: **512-473-3579**		E-mail Address: **joe.bentley@lcra.org**	
D. Facility Location Information:				
Street Address: **2001 Ferguson Rd**				
If no street address, provide clear driving directions to the site in writing:				
City: **Horseshoe Bay**		County: **Llano**		ZIP Code: **78657**
E. TCEQ Account Identification Number (leave blank if new site or facility): **LL-0006-O**				
F. Is a TCEQ Core Data Form (TCEQ Form No. 10400) attached?				☒ YES ☐ NO
G. TCEQ Customer Reference Number *(leave blank if unknown)*: **CN600253637**				
H. TCEQ Regulated Entity Number *(leave blank if unknown)*: **RN100219468**				
II. IMPORTANT GENERAL INFORMATION				
A. Is confidential information submitted with this application?				☐ YES ☒ NO
If "YES," is each "confidential" page marked "**CONFIDENTIAL**" in large red letters?				☐ YES ☐ NO

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

II. IMPORTANT GENERAL INFORMATION ***(continued)***	
B. Is this application in response to a TCEQ investigation or enforcement action?	☐ YES ☒ NO
If "YES", attach a copy of any correspondence from the TCEQ	
C. Number of New Jobs: **600 construction jobs, 0 permanent jobs**	
D. Names of the State Senator and district number for this facility site: **Troy Fraser, Senate District 24**	
Names of State Representative and district number for this facility site: **Harvey Hilderbran, House District 53**	
E. For Concrete Batch Plants, and PSD, or Nonattainment Permits that require public notice, name of the County Judge for this facility site:	
Mailing Address:	
City: State: ZIP Code:	
F. For Concrete Batch Plants, is the facility located in a municipality or an extraterritorial jurisdiction of a municipality?	☐ YES ☐ NO
If "YES," list the name(s) of the Presiding Officer(s) for this facility site:	
Mailing Address:	
City: State: ZIP Code:	
III. FACILITY AND SOURCE INFORMATION	
A. Site Name: **Thomas C. Ferguson Power Plant**	
B. Area Name/Type of Facility: **Electric Generating Plant**	☒ Permanent ☐ Portable
C. Principal Company Product or Business: **Electricity Generation**	
Principal Standard Industrial Classification Code: **4911**	
D. Projected Start of Construction Date: **March 2012**	Projected Start of Operation Date: **January 2014**
IV. TYPE OF PERMIT ACTION REQUESTED	
A. Permit Number *(if existing)*:	
B. Is this an initial permit application?	☒ YES ☐ NO

If "YES," check the type of permit requested *(check all that apply)*:

☒ State Permit
☐ Flexible Permit
☐ Multiple Plant Permit
☐ Nonattainment Federal Permit
☒ Prevention of Significant Deterioration Federal Permit
☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g)
Other: ____________________

IV. TYPE OF PERMIT ACTION REQUESTED *(continued)*			
C. Is this a permit amendment?			☐ YES ☒ NO
Is this a permit revision?? (SB 1126 change)			☐ YES ☒ NO
If "YES," check the type of permit requested *(check all that apply)*: ☐ State Permit Amendment ☐ Flexible Permit Amendment ☐ Multiple Plant Permit Amendment ☐ Nonattainment Major Modification ☐ Prevention of Significant Deterioration Major Modification ☐ Hazardous Air Pollutants Permit Federal Clean Air Act § 112(g) Modification Other:______			
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with Senate Bill 1673? [THSC 382.055(a)(2)](80th Legislative)			☐ YES ☐ NO **Not applicable**
E. Is this application for a change of location of previously permitted facilities?			☐ YES ☒ NO
If "YES," answer IVE. 1. - IVE. 4.			
1. Current location of facility:			
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:			
City:	County:	ZIP Code:	
2. Proposed location of facility:			
Street Address *(If no street address, provide clear driving directions to the site in writing.)*:			
City:	County:	ZIP Code:	
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions?			☐ YES ☐ NO
If "NO," attach detailed information.			
4. Is the site where the facility is moving considered major?			☐ YES ☐ NO
F. Is this a relocation?			☐ YES ☒ NO
G. Are there any standard permits, exemptions or permits by rule to be consolidated into this permit?			☐ YES ☒ NO

IV. TYPE OF PERMIT ACTION REQUESTED *(continued)*	
H. Are you permitting a facility or group of facilities that have planned maintenance, startup and shutdown emissions that cannot be authorized by a permit by rule or standard permit or that are authorized by a permit by rule or standard permit and are being rolled into this permit?	☒ YES ☐ NO
If "YES," attach information on any changes to emissions under this application as specified in Sections IX, and X.	
If "YES," answer IVH. 1 -IVH. 3.	
1. Are the activities to be included in this permit covered by any previously existing MSS authorizations?	☐ YES ☒ NO
If "YES," provide a listing of all other authorizations (permit by rule or standard permit and the associated registration number if any).	
2. Have the emissions been previously submitted as part of an emissions inventory?	☐ YES ☒ NO
3. List which years the MSS activities were included in emissions inventory submittals:	
I. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)	
Is this facility located at a site required to obtain a federal operating permit under 30 TAC Chapter 122?	☒ YES ☐ NO ☐ To be Determined
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this PI-1 application is approved. ☒ FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ To be determined ☐ None	
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	
V. PERMIT FEE INFORMATION	
A. Fee paid for this application:	$ **75,000**
1. Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
2. Is a Table 30 entitled, "Certification of 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 Amendments

VI. PUBLIC NOTICE APPLICABILITY	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this an application for a major modification of a PSD, NA or 30 TAC § 112(g) permit?	☐ YES ☒ NO
C. Is this a state permit amendment application?	☐ YES ☒ NO
If "YES," answer VIC. 1. - VIC. 3.	
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
2. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
3. List the total annual emission increases associated with the application (*list all that apply*):	
Volatile Organic Compounds (VOC):	tpy
Sulfur Dioxide (SO_2):	tpy
Carbon Monoxide (CO):	tpy
Hazardous Air Pollutants (HAPs):	tpy
Nitrogen Oxides (NO_x):	tpy
Particulate Matter (PM):	tpy
PM_{10}:	tpy
$PM_{2.5}$:	tpy
Lead (Pb):	tpy
Other air contaminants not listed above:	tpy

VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***		
A. Responsible Person:		
Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): **Joe Bentley**		
Title: **Environmental Program Manager**		
Mailing Address: **P.O. Box 220**		
City: **Austin**	State: **TX**	ZIP Code: **78767**
Telephone No.: **512-473-3272**	Fax No.: **512-473-3579**	E-mail Address: **joe.bentley@lcra.org**

VII. PUBLIC NOTICE INFORMATION *(complete if applicable)*		
B. Technical Contact:		
Company Name : **Lower Colorado River Authority**		
Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): **Joe Bentley**		
Title: **Environmental Program Manager**		
Mailing Address: **P.O. Box 220**		
City: **Austin**	State: **TX**	ZIP Code: **78767**
Telephone No.: **512-473-3272**	Fax No.: **512-473-3579**	E-mail Address: **joe.bentley@lcra.org**
C. Application in Public Place:		
Name of Public Place: **Llano County Public Library**		
Physical Address: **102 E. Haynie**		
City: **Llano**	County: **Llano**	
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 ☐ N/A	
Complete VII.D. 1. - VII.D. 3., as applicable.		
D.1. Name of the Mayor for this facility site:		
Bob Lambert		
Mailing Address: **No. 1 Community Drive**		
City: **Horseshoe Bay**	State: **TX**	ZIP Code: **78657**
D.2. Name of the Federal Land Manager for this facility site: **NA**		
Mailing Address:		
City:	State:	ZIP Code:
D.3. Name of the Indian Governing Body for this facility site: **NA**		
Mailing Address:		
City:	State:	ZIP Code:

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

TCEQ

VII. PUBLIC NOTICE INFORMATION ***(complete if applicable)***	
E. 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," which language is **required** by the bilingual program?	**Spanish**
VIII. 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 source under 30 TAC Chapter 122, Federal Operating Permit Program?	☒ YES ☐ NO
C. Are the site emissions of any individual air contaminant greater than 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all air contaminants combined greater than 75 tpy?	☒ YES ☐ NO

IX. TECHNICAL INFORMATION				
A. Is a current area map attached?				☒ YES ☐ NO
Are any schools located within 3,000 feet of this facility?				☐ YES ☒ NO
B. Is a plot plan of the plant property attached?				☒ YES ☐ NO
C. Is a process flow diagram and a process description attached?				☒ YES ☐ NO
D. Maximum Operating Schedule:	Hours: **8,760**	Day(s):	Week(s):	Year(s):
Seasonal Operation?				☐ YES ☒ NO
If "YES," please describe.				
E. Are worst-case emissions data and calculations attached?				☒ YES ☐ NO
1. Is a Table 1(a) entitled, "Emission Point Summary Table," attached?				☒ YES ☐ NO
2. Is a Table 2 entitled, "Material Balance Table," attached?				☒ YES ☐ NO
3. Are equipment, process, or control device tables attached?				☒ YES ☐ NO
F. Are actual emissions for the last two years (determination federal applicability) attached?				☒ YES ☐ NO

X. STATE REGULATORY REQUIREMENTS *Applicants must be in compliance with all applicable state regulations to obtain a permit or amendment.*	
A. The emissions from the proposed facility will comply with all rules and regulations of the TCEQ and details are attached?	☒ YES ☐ NO
B. The proposed facility will be able to measure emissions of significant air contaminants and details are attached?	☒ YES ☐ NO
C. A demonstration of Best Available Control Technology (BACT) is attached?	☒ YES ☐ NO
D. The proposed facilities will achieve the performance in the permit application and compliance demonstration or record keeping information is attached?	☒ YES ☐ NO
E. Is atmospheric dispersion modeling attached?	☐ YES ☒ NO
F. Does this application involve any air contaminants for which a "disaster review" is required?	☐ YES ☒ NO
If "YES," details must be attached.	
Note: For a list of air contaminants for which a "disaster review" will be required, refer to the NSRPD Disaster Review Guidance Document at www.tceq.state.tx.us/permitting/air/rules/federal/63/63hmpg.html.	
G. Is this facility or group of facilities located at a site within an Air Pollutant Watch List (APWL) area?	☐ YES ☒ NO
If "YES," answer X.G. 1. - X.G. 3.	
1. List the APWL Site Number:	
2. Does the site emit a pollutant of concern for the APWL area in which the site is located?	☐ YES ☐ NO
3. If "YES," list the pollutant(s) of concern emitted by this site:	
H. Is this facility or group of facilities located at a site within the Houston/Galveston nonattainment area? (Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, or Waller Counties)	☐ YES ☒ NO
If "YES," answer X.H. 1. - X.H. 4.	
1. Does the facility or group of facilities located at this site have an uncontrolled design capacity to emit 10 tpy or more of NO_X?	☐ YES ☐ NO
2. Is this site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☐ YES ☐ NO
3. Does this action make the site subject to 30 TAC Chapter 101, Subchapter H, Division 3 (Mass Emissions Cap and Trade)?	☐ YES ☐ NO
4. Does this action require the site to obtain additional emission allowances?	☐ YES ☐ NO

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

XI. FEDERAL REGULATORY REQUIREMENTS **Applicants must be in compliance with all applicable federal regulations to obtain a permit or amendment.** ***If any of the following questions are answered "YES, the application must contain detailed attachments addressing applicability, identify federal regulation Subparts, show how requirements are met, and include compliance information.***	
A. Does a 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 a 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D. Does nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Does prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Does Hazardous Air Pollutant Major Source [FAA § 112(g)] requirements apply to this application?	☐ YES ☒ NO
XII. COPIES OF THIS APPLICATION	
A. Has the required fee been sent separately with a copy of this Form PI-1 to the TCEQ Revenue Section? *(MC 214, P.O. Box 13088, Austin, Texas 78711).*	☒ YES ☐ NO ☐ NA
B. Are the Core Data Form, Form PI-1, and all attachments being sent to the TCEQ in Austin?	☒ YES ☐ NO
OPTIONAL: Has an extra copy of the Core Data Form, Form PI-1 and all attachments been sent to the TCEQ in Austin?	☒ YES ☐ NO
If "YES," please mark this application as "COPY."	
C. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to the appropriate TCEQ regional office?	☒ YES ☐ NO
D. Is a copy of the Core Data Form, the Form PI-1, and all attachments being sent to each appropriate local air pollution control program(s)? **N/A**	☐ YES ☐ NO
List all local air pollution control program(s):	
E. Is a copy of the Core Data Form, Form PI-1, and all attachments (without confidential information) being sent to the EPA Region 6 office in Dallas, Texas? (federal applications only)	☒ YES ☐ NO
F. This facility is located within 100 kilometers of the Rio Grande River and a copy of the application was sent to the International Boundary and Water Commission (IBWC):	☐ YES ☒ NO
G. This facility is located within 100 kilometers of a federally-designated Class I area and a copy of the application was sent to the appropriate Federal Land Manager:	☐ YES ☒ NO

XIII. PROFESSIONAL ENGINEER (P.E.) SEAL	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If "YES," the application must be submitted under the seal of a Texas licensed Professional Engineer (P.E.).	
XIV. DELINQUENT FEES AND PENALTIES	
Notice: 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.state.tx.us/agency/delin/index.html.	
XV. 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. I further state that I have read and understand TWC §§ 7.177-7.183, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and TWC § 7.187, pertaining to CRIMINAL PENALTIES.	
NAME: Kenneth W. Taylor	
SIGNATURE: Kenneth W. Taylor *Original Signature Required*	
DATE: 10/29/10	

2.0 PROJECT SCOPE

2.1 INTRODUCTION

LCRA is studying the feasibility of replacing its aging natural gas-fired Thomas C. Ferguson Power Plant with a new combined-cycle power plant that would be more efficient, more reliable, and have improved environmental controls. LCRA began a year-long evaluation in April 2010 to decide whether replacing Ferguson is a financially and technically feasible option. In anticipation of moving forward with the project, a NSR/PSD permit application was submitted to the TCEQ on October 29, 2010.

Preliminary evaluations indicate that replacing the 37-year-old Ferguson unit will help LCRA manage wholesale power costs over the long-term because a new, combined-cycle generation facility will burn less fuel (natural gas) and produce fewer emissions per kilowatt-hour. If the project proceeds, LCRA will build the new power facility at the Ferguson site on Lake LBJ in Llano County. The existing Ferguson steam electric generating unit, including the boiler and turbine/generator set, would be retired following completion of the new facility. The new plant will be able to vary electrical output to better respond to large fluctuations in wind generation in West Texas.

The LCRA Board of Directors in April 2010 authorized staff to begin a year-long study to gather additional information about the projected costs and long-term benefits of replacing the aging Ferguson unit with a combined-cycle power plant. In late October 2010, LCRA issued a request for proposals for engineering, procurement, and construction (EPC) contractors. The proposals will provide firm costs that will help LCRA determine whether to proceed with the project. LCRA staff plans to take a recommendation to the LCRA Board in the spring of 2011. If the LCRA Board approves moving forward with the project, LCRA expects that a three-year construction phase could take place from late 2011 to 2014.

LCRA expects that a new combined-cycle power plant will also use less water because the new steam turbine will be much smaller than the existing steam turbine. In addition, as part of this project LCRA is removing the three 1.8 million gallon fuel oil tanks that it has maintained on-site for use in periods when natural gas is curtailed or increases significantly in price. While the Ferguson Power Plant already has good environmental protection measures in place, this action will completely eliminate the risks associated with storing fuel oil on-site.

Included at the end of this section are a Process Flow Diagram, Plot Plan, and Area Map.

2.2 NATURAL-GAS-FIRED COMBINED CYCLE COMBUSTION TURBINES

The plant will consist of two identical natural gas-fired combustion turbines (CTs), with two models being considered: the General Electric 7FA and the Siemens SGT6-5000F as illustrated in the attached Process Flow Diagram. Both turbines being considered are highly efficient, F-

Class, turbines which incorporate high compression ratio and high combustion temperature technology. The selection of the turbine will be based on a variety of factors including heat rate, ramp rate, emission levels, low load operation, as well as economic factors. Each combustion turbine will exhaust to an unfired Heat Recovery Steam Generator. Emission point numbers (EPNs) for the combustion turbine/HRSG units are identified as U1-STK and U2-STK.

The two units will be capable of being dispatched rapidly (up to 30 MW per minute each) as needed to meet Electric Reliability Council of Texas (ERCOT)'s system requirements. The units may also operate at reduced load (i.e., possibly as low as 45 percent of base load) to respond quickly to changes in demand for power. The units will also be prone to frequent and rapid load swings due to the plant being located near the connections to the transmission lines providing wind power from West Texas.

Steam produced by each of the two HRSGs will be routed to the steam turbine (Facility Identification Number (FIN) STG-1). The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the ERCOT power grid. Each GE combustion turbine model has a maximum base-load electric power output of approximately 195 MW and the Siemens model has a maximum base-load output of about 224 MW. The maximum electric power output from the steam turbine in both the GE and Siemens configurations is approximately 200 MW.

2.3 NATURAL GAS PIPING

Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbines. Fugitive emissions from natural gas piping components will include emissions of methane and CO_2. Emissions from the natural gas piping are designated as EPN NG-FUG.

2.4 DIESEL-FIRED EMERGENCY EQUIPMENT

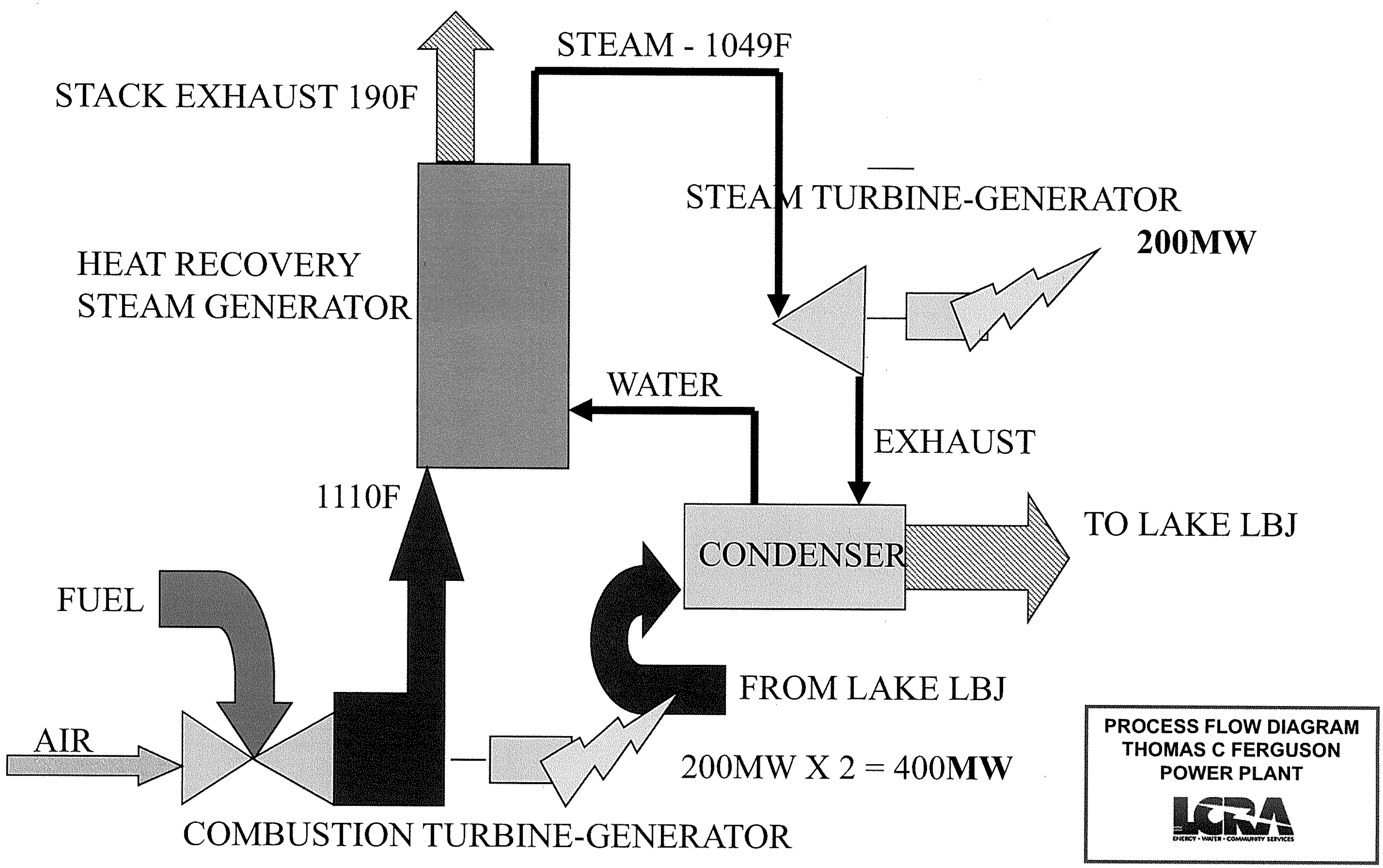
The site will be equipped with one 1,340 hp diesel-fired emergency generator (FIN EMGEN1, EPN EMGEN1-STK) and one 617 hp firewater pump (FIN FWP1, EPN FWP1-STK). The engines running this equipment will fire low sulfur diesel fuel. Use of these engines for purposes of maintenance checks and readiness testing will be limited to 100 hours per year each.

2.5 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The project will include six new circuit breakers in the electrical switchyard and two new combustion turbine generator circuit breakers which will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas 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.

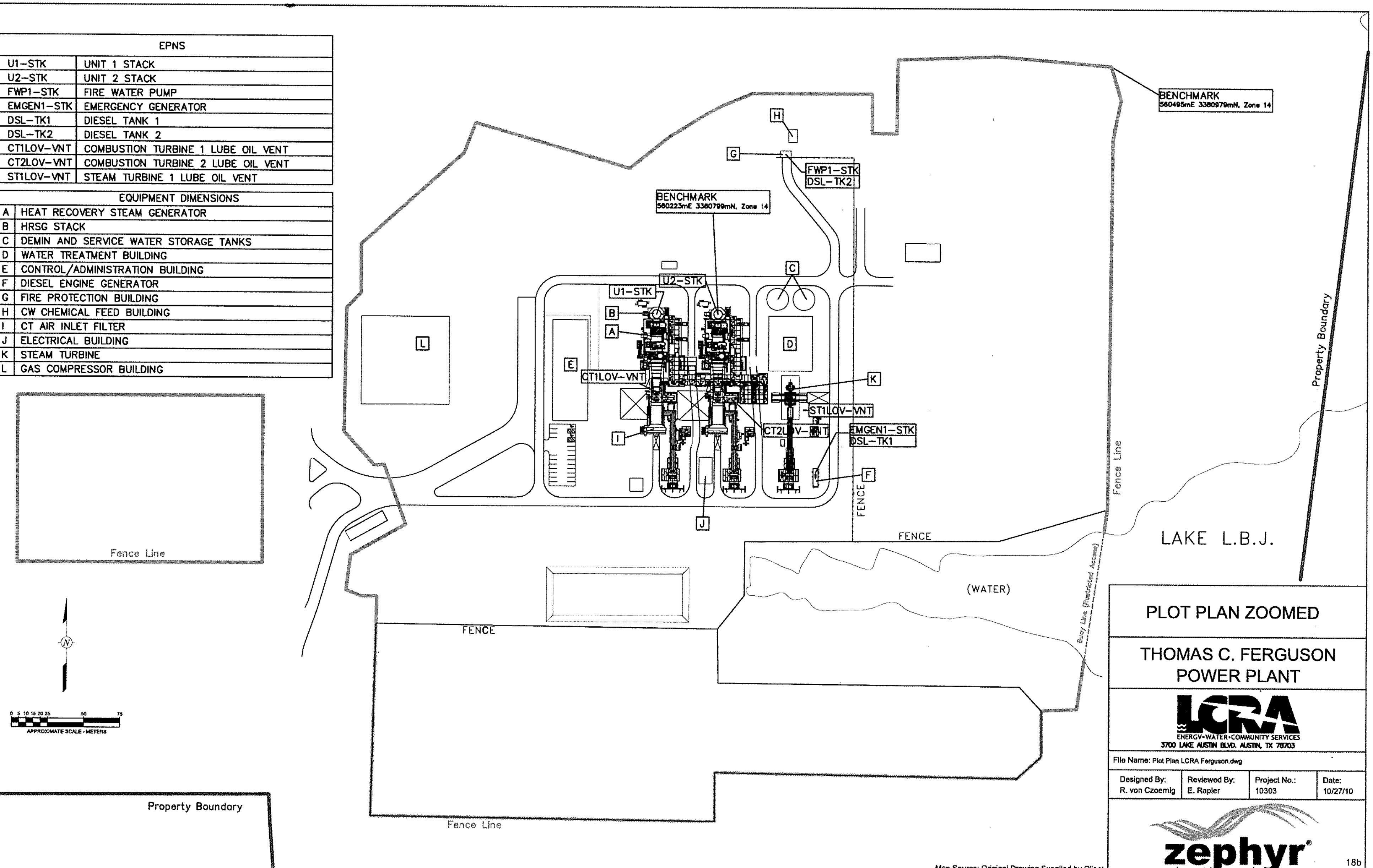
The proposed circuit breakers in the switchyard and at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6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

Process Flow Diagram



EPNS	
U1-STK	UNIT 1 STACK
U2-STK	UNIT 2 STACK
FWP1-STK	FIRE WATER PUMP
EMGEN1-STK	EMERGENCY GENERATOR
DSL-TK1	DIESEL TANK 1
DSL-TK2	DIESEL TANK 2
CT1LOV-VNT	COMBUSTION TURBINE 1 LUBE OIL VENT
CT2LOV-VNT	COMBUSTION TURBINE 2 LUBE OIL VENT
ST1LOV-VNT	STEAM TURBINE 1 LUBE OIL VENT

EQUIPMENT DIMENSIONS	
A	HEAT RECOVERY STEAM GENERATOR
B	HRSG STACK
C	DEMIN AND SERVICE WATER STORAGE TANKS
D	WATER TREATMENT BUILDING
E	CONTROL/ADMINISTRATION BUILDING
F	DIESEL ENGINE GENERATOR
G	FIRE PROTECTION BUILDING
H	CW CHEMICAL FEED BUILDING
I	CT AIR INLET FILTER
J	ELECTRICAL BUILDING
K	STEAM TURBINE
L	GAS COMPRESSOR BUILDING



PLOT PLAN ZOOMED

THOMAS C. FERGUSON
POWER PLANT

LCRA
ENERGY•WATER•COMMUNITY SERVICES
3700 LAKE AUSTIN BLVD. AUSTIN, TX 78703

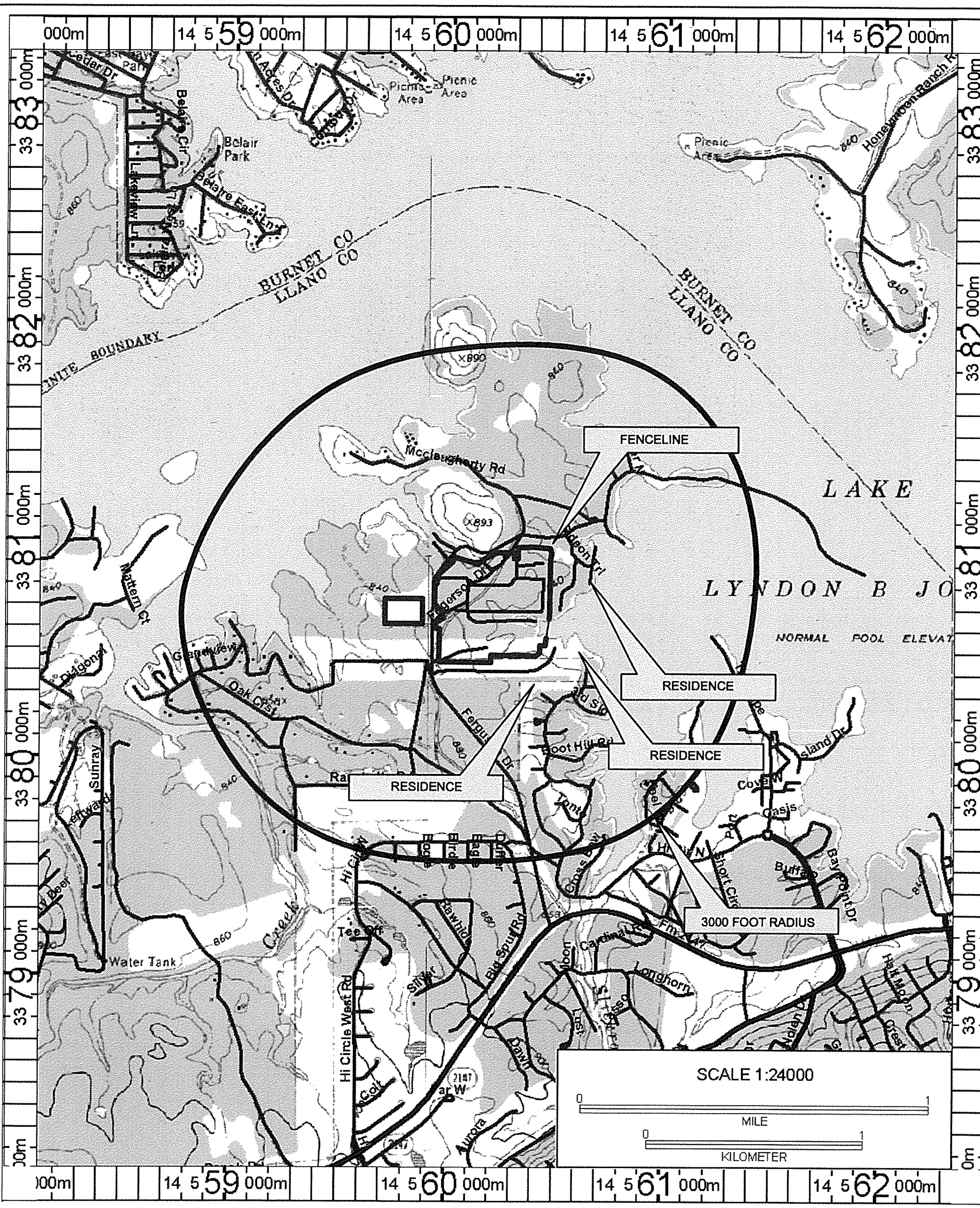
File Name: Plot Plan LCRA Ferguson.dwg

Designed By:	Reviewed By:	Project No.:	Date:
R. von Czoernig	E. Rapier	10303	10/27/10

zephyr® environmental corporation

18b

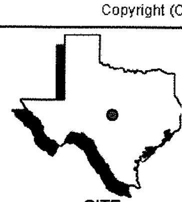
Map Source: Original Drawing Supplied by Client



Datum: NAD83

Copyright (C) 2008, MyTopo

Digital USGS 7.5 Minute Topographic Series
—MARBLE FALLS, TX Quadrangle (1967)
—DUNMAN MT, TX Quadrangle (1982)
MAP SOURCE: Terrain Navigator Pro



SITE LOCATION

zephyr environmental corporation

AREA MAP

THOMAS C. FERGUSON POWER PLANT

LCRA ENERGY·WATER·COMMUNITY SERVICES

File Name: Plot Plan Ferguson.dwg			
Designed By: R. von Czoernig	Reviewed By: E. Rapier	Project No.: 10303	Date: 10/27/10

3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM COMBINED CYCLE COMBUSTION TURBINES

GHG emission calculations for the combined cycle combustion turbines are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[3] CO_2 emissions are calculated using equation G-4 of the Acid Rain Rules.[4]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{-}4)$$

Where:

W_{CO2}= CO_2 emitted from combustion, tons/yr.

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

F_c= Carbon based F-factor, 1040 scf/MMBtu for natural gas.

H = Annual heat input in MMBtu.

Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

Emissions of CH_4 and N_2O are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5] The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

3.2 GHG EMISSIONS FROM NATURAL GAS PIPING COMPONENTS

GHG emission calculations for natural gas piping component fugitive emissions are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[6] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis.

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[3] 40 C.F.R. 98, Subpart D – *Electricity Generation*

[4] 40 C.F.R. 75, Appendix G – *Determination of CO_2 Emissions*

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

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

The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[7]

3.3 GHG EMISSIONS FROM DIESEL FIRED EMERGENCY ENGINES

CO_2 emission calculations for the diesel-fired fire pump engine and the emergency generator 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.[8] CH_4 and N_2O emission calculations for the diesel-fired fire pump engine and the emergency generator are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[9] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[10]

3.4 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from new and existing circuit breakers are calculated using a predicted SF_6 annual leak rate of 0.5 lb/year for 24 lb SF_6 insulated circuit breakers and 1.0 lb/year for 58 lb SF_6 insulated circuit breakers. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[11]

3.5 GHG EMISSIONS FROM EXISTING NATURAL-GAS-FIRED BOILER

GHG emission calculations for the existing natural-gas-fired boiler are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[12] CO_2 emissions are calculated using equation G-4 from the Acid Rain Rules.[13] Emissions of CH_4 and N_2O are calculated using the emission factors (kg/MMBtu) for natural gas combustion 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]

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

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

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

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

[11] *Id.*

[12] 40 C.F.R. 98, Subpart D – *Electricity Generation*

[13] *Determination of CO_2 Emissions*, 40 C.F.R. Pt. 75, App. G, Eq. G-4.

[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.

Table 3-1
Plantwide GHG Emission Summary
LCRA - Thomas C. Ferguson Power Plant

Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
Unit 1 (Siemens SGT6-5000F)	U1-STK	1,030,277	1,031,248
Unit 2 (Siemens SGT6-5000F)	U2-STK	1,030,277	1,031,248
Natural Gas Fugitives	NG-FUG	16	327
Emergency Generator	EMGEN1-STK	763	766
Fire Water Pump	FWP1-STK	351	353
SF_6 Insulated Equipment	SF6-FUG	0.006	131
		2,061,685	2,064,072

Table 3-2

GHG Emission Calculations - Combined Cycle Combustion Turbines

LCRA - Thomas C. Ferguson Power Plant

GHG Emissions Contribution From Natural Gas Fired Combustion Turbines

EPN	Average Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions[3] (tpy)	Global Warming Potential[4]	CO_2e (tpy)
U1-STK (GE Scenario)	1,746	CO_2		908,957.6	1	908,957.6
		CH_4	1.0E-03	16.8	21	353.3
		N_2O	1.0E-04	1.7	310	521.6
			Totals	**908,976.1**		**909,832.5**
U2-STK (GE Scenario)	1,746	CO_2		908,957.6	1	908,957.6
		CH_4	1.0E-03	16.8	21	353.3
		N_2O	1.0E-04	1.7	310	521.6
			Totals	***908,976.1***		**909,832.5**
Total for 2 Turbines				***1,817,952.3***		***1,819,665.0***

EPN	Average Heat Input[1] (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[2]	GHG Mass Emissions[3] (tpy)	Global Warming Potential[4]	CO_2e (tpy)
U1-STK (Siemens Scenario)	1,979	CO_2		1,030,256.1	1	1,030,256.1
		CH_4	1.0E-03	19.1	21	400.5
		N_2O	1.0E-04	1.9	310	591.2
			Totals	**1,030,277.1**		**1,031,247.7**
U2-STK (Siemens Scenario)	1,979	CO_2		1,030,256.1	1	1,030,256.1
		CH_4	1.0E-03	19.1	21	400.5
		N_2O	1.0E-04	1.9	310	591.2
			Totals	***1,030,277.1***		**1,031,247.7**
Total for 2 Turbines				***2,060,554.1***		***2,062,495.4***

Note

1. *The average heat input for the GE and Siemens scenarios are based on the HHV heat input at 100% load at 69 °F ambient temperature.*
2. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
3. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (Fc \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

Fc = Carbon based F-factor, 1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 °F

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

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

Table 3-3
GHG Emission Calculations - Natural Gas Piping
LCRA - Thomas C. Ferguson Power Plant

GHG Emissions Contribution From Fugitive 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)
NG-FUG	Valves	Gas/Vapor	520	0.123	0.45	11.20	
	Flanges	Gas/Vapor	1460	0.017	0.17	4.35	
	Compressors	Gas/Vapor	3	0.002	0.00004	0.00105	
GHG Mass-Based Emissions					0.62	15.55	***16.2***
Global Warming Potential[4]					1	21	
CO_2e Emissions					0.62	326.54	***327.2***

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* *1.41%*
3. *CH_4 emissions based on vol% of CH_4 in natural gas* *96.10%*
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

520 valve	0.123 scf gas	0.0141 scf CO_2	lbmole	44.01 lb CO_2	8760 hr	ton =	0.45 ton/yr
	hr * valve	scf gas	385.5 scf	lbmole	yr	2000 lb	

Table 3-4
GHG Emission Calculations - Emergency Engines
LCRA - Thomas C. Ferguson Power Plant

GHG Emissions Contribution From Diesel Combustion In Emergency Engines

Assumptions	Generator	Fire Water Pump	
Ann.Operating Schedule	100	100	hours/year
Power Rating	1,340	617	hp
Brake Specific Fuel Consumption	7,000	7,000	Btu/hp-hr

EPN	Heat Input (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions (tpy)	Global Warming Potential[2]	CO_2e (tpy)
EMGEN1-STK	93.8	CO_2	73.96	763.1	1	763.1
		CH_4	3.0E-03	0.03	21	0.7
		N_2O	6.0E-04	0.01	310	1.9
				763.16		**765.7**
FWP1-STK	43.2	CO_2	73.96	351.4	1	351.4
		CH_4	3.0E-03	0.01	21	0.3
		N_2O	6.0E-04	0.003	310	0.9
			Totals	***351.39***		**352.6**

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 3-5

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

LCRA - Thomas C. Ferguson Power Plant

Assumptions		
Number of new 24 lb SF_6 insulated circuit breakers	2	
Number of new 58 lb SF_6 insulated circuit breakers	6	
Number of existing 58 lb SF_6 insulated circuit breakers	4	
Estimated SF_6 leak rate for 24 lb circuit breakers	0.5	lb/yr/circuit breaker
Estimated SF_6 leak rate for 58 lb circuit breakers	1	lb/yr/circuit breaker
New Equipment		
Estimated annual SF_6 mass emission rate	0.0035	ton/yr
Global Warming Potential[1]	23,900	
Estimated annual CO_2e emission rate	83.7	ton/yr
Existing Equipment		
Estimated annual SF_6 mass emission rate	0.002	ton/yr
Global Warming Potential[1]	23,900	
Estimated annual CO_2e emission rate	47.8	ton/yr

<u>Note</u>

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

Table 3-6

GHG Emission Calculations - Existing Boiler (EPN Stack 1)

LCRA - Thomas C. Ferguson Power Plant

GHG Potential To Emit Emissions From Natural Gas Fired Boiler (EPN Stack 1)

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
Stack 1	42,398,400	CO_2		2,519,676.3	1	2,519,676.3
		CH_4	1.0E-03	10.69	21	224.5
		N_2O	1.0E-04	1.07	310	331.5
			Totals	**2,519,688.1**		**2,520,232.3**

GHG Baseline Actual Emissions Natural Gas Fired Boiler (EPN Stack 1)

EPN	Average Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
Stack 1	9,699,950	CO_2		576,454.2	1	576,454.2
		CH_4	1.0E-03	10.69	21	224.5
		N_2O	1.0E-04	1.07	310	331.5
			Totals	**576,465.9**		**577,010.2**

Note

1. *Maximum annual heat input based on 440,000 kW * 11,000 Btu/kWh * 8,760 hr/yr*
2. *Average annual heat input for baseline period of July 2008 - June 2010*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

4. *CO2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (Fc \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 *emitted from combustion, tons/yr*

Fc = Carbon based F-factor, 1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = *1/385 scf* CO_2*/lbmole at 14.7 psia and 68* $^\circ F$

MW_{CO2} = *Molecule weight of* CO_2*, 44.0 lb/lbmole*

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

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

On October 29, 2010, LCRA submitted a state/PSD air permit application to the TCEQ to authorize the construction of two new combined cycle electric generating units at the Thomas C. Ferguson Power Plant in Llano County, Texas. The application showed that the project triggered PSD review for carbon monoxide, volatile organic compounds, particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers, particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, and sulfuric acid mist.

Step 1 of the PSD Tailoring rules require that between January 2, 2011 and June 30, 2011, when an existing major source undertakes a physical or operational change that would be subject to PSD anyway due to emissions of another regulated new source review pollutant and increases its emissions of GHGs by at least the specified threshold amounts, the GHGs are treated as subject to regulation and therefore as a regulated NSR pollutant from that source. This type of modification is referred to as an "anyway modification" by the EPA. In the EPA guidance document *PSD and Title V Permitting Guidance for Greenhouse Gases,* the following PSD Applicability Test was provided for Step 1 of the PSD Tailoring rule for existing sources:

EPA Tailoring Rule Step 1 - PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011, to June 30, 2011

PSD applies to the GHG emissions from a proposed modification to an existing major source if ***both*** of the following are true:

- Not considering its emissions of GHGs, the modification would be considered a major modification anyway and therefore would be required to obtain a PSD permit (called an "anyway modification"), ***and***
- The emissions increase ***and*** the **net** emissions increase of GHGs from the modification would be equal to or greater than 75,000 TPY on a CO_2e basis ***and*** greater than zero TPY on a mass basis.

This project fits in the category of an "anyway modification" since PSD is triggered for other regulated pollutants. Since the net emissions increase of GHG is greater than 75,000 ton/yr of CO_2e and greater than zero ton/yr on a mass basis, PSD is triggered for GHG emissions. The emissions netting analysis is documented on the attached TCEQ PSD netting tables: Table PSD-1, Table PSD-2, and Table PSD-3. Also included in Appendix A is the "The GHG PSD APPLICABILITY FLOWCHART – EXISTING SOURCES (January 2, 2011 through June 30, 2011) from the *PSD and Title V Permitting Guidance for Greenhouse Gases*

Texas Natural Resource Conservation Commission
Prevention of Significant Deterioration (PSD) Review

TABLE PSD-1
PSD AIR QUALITY APPLICABILITY SUPPLEMENT

TO BE COMPLETED BY APPLICANT AT TIME OF APPLICATION

A permit applicant must complete this table if PSD netting is required or requested by permit engineer. This is not a stand-alone document. Please refer to the *TNRCC PSD Air Quality Guidance Document* for specific details regarding information required by this form. For additional information regarding PSD applicability and review, please refer to 40 CFR Part 52 Section 21 and EPA's Draft*New Source Review Workshop Manual o* f October 1990 which provides examples for illustration.

Permit No.	93938/PSD-TX-1244		
Company	Lower Colorado River Authority	TNRCC Air Quality Account I.D.	LL-0006-O
Company Contact	Michael McCluskey	Phone Number	512-473-6857
Facility Location or Street Address	2001 Ferguson Rd.		
City	Horseshoe Bay	County	Llano
Permitted Unit I.D. and Name	Thomas C. Ferguson Power Plant		
Permit Activity:	☐ New Major Source	☑ Major Modification	
Project or Process Description	Replacing existing boiler with two combined cycle gas turbine units		

Operating Schedule: 24 hrs/day 7 days/wk 52 wks/yr 8760 hrs/yr ______ Continuous
Or throughput ______

The information provided on this form (and Tables PSD-2 and PSD-3, if applicable) is true and correct.

______________ Signature ______________ Title 03/16/2011 Date

If Prevention of Significant Deterioration (PSD) review is required, then the applicant must send a complete application to EPA Region 6 at the address below. EPA Region 6 must also receive copies of all subsequent correspondence.

EPA Region 6
New Source Review Section
1445 Ross Avenue
Dallas, Texas 75202-2733

LIST RELEVANT DATES:

A. 11/01/11 Estimated start of construction.
B. 11/01/06 5 years prior to estimated start of construction.
C. 01/01/14 Estimated start of operation.

DEFINE CONTEMPORANEOUS PERIOD (from B to C): 11/01/06 to 01/01/14
From 5 years prior to estimated start of construction through estimated start of operation.

	Yes	No	Regulated Pollutant[1]							
			GHG	CO_2e						
Existing site potential to emit (tpy)			2,519,688	2,520,232						
Proposed project increases[2] (tpy)			2,061,685	2,064,072						
Nonattainment New Source Review Applicability: If the proposed project will be located in any area that is designated nonattainment for any pollutants, place a check to the right in the column under that pollutant(s) and complete a Table 1N.										
Is the existing site one of the 28 named sources?[3]	X									
Is the existing site a major source?[4]	X									
Existing site is a major source:										
Is netting required? If "Yes" attach Tables PSD-2 and PSD-3.[5]	X									
Significance level as defined in 40 CFR 52.21(b)(23)[6]			0	75000						
Net contemporaneous change from Table PSD-2 (tpy)			1,485,219	1,487,014						
Is PSD review applicable? Answer "Yes" or "No" under each applicable pollutant.			Yes	Yes						
Existing site is NOT a major source:										
Is the proposed project by itself one of the 28 named sources?[3]										
Is the proposed project a major source by itself? (No consideration is given to any emissions decreases.)[4]										
Once the project is considered major all other pollutants are compared to their respective significance levels.[6] Netting is not allowed. **Is PSD review applicable?** Answer "Yes" or "No" under each applicable pollutant.										

[1] Regulated pollutants include criteria pollutants (pollutants for which a National Ambient Air Quality Standard [NAAQS] exists) and noncriteria pollutants (pollutants regulated by EPA for which no NAAQS exists).

[2] Defined in Part A of the TNRCC *PSD Air Quality Guidance Document* .

[3] The 28 named source categories are listed in 40 CFR 52.21(b)(1) and Table A of the TNRCC *PSD Air Quality Guidance Document* .

[4] Refer to Part C "major source determination" of the TNRCC *PSD Air Quality Guidance Document* .

[5] Refer to Part E2 of the TNRCC *PSD Air Quality Guidance Document* .

[6] Significant emissions are defined in 40 CFR 52.21(b)(23) and Table B of the TNRCC *PSD Air Quality Guidance Document* .

[7] The GHG and CO2e significant level is based on the GHG Tailoring Rule.

TABLE PSD-2
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Lower Colorado River Authority
Permit Application No. 93938/PSD-TX-1244

Page 1 of 2
Regulated Pollutant GHG

	PROJECT DATE[2]	EMISSION UNIT AT WHICH REDUCTION OCCURED[3] FIN	EPN	PERMIT NO.	PROJECT NAME OR ACTIVITY	A ALLOWABLE EMISSIONS AFTER THE ACTIVITY[4] (tons/year)	B ACTUAL EMISSIONS PRIOR TO THE ACTIVITY[4] (tons/year)	C (tons/yr) DIFFERENCE (A-B)[5]	CREDITABLE DECREASE OR INCREASE[6]	REASON CODE[7]
1	01/01/2014		Stack 1	45605	Shut Down Boiler	0	576,466	-576,466	-576,466	e1a
2	01/01/2014	CTG1	U1-STK	93938	Start Up New Unit	1,030,277	0	1,030,277	1,030,277	
3	01/01/2014	CTG2	U2-STK	93938	Start Up New Unit	1,030,277	0	1,030,277	1,030,277	
4	01/01/2014	NG-FUG	NG-FUG	93938	Start Up New Unit	16	0	16	16	
5	01/01/2014	EMGEN1	EMGEN1-STK	93938	Start Up New Unit	763	0	763	763	
6	01/01/2014	FWP1	FWP1-STK	93938	Start Up New Unit	351	0	351	351	
7	01/01/2014	SF6-FUG	SF6-FUG	93938	Start Up New Unit	0.006	0.002	0.004	0.004	
8										
9										
10										
11										
12										
13										
14										
							PAGE SUBTOTAL[8]		1,485,219	
	Summary of Contemporaneous Changes						TOTAL		1,485,219	

TABLE PSD-2

PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Lower Colorado River Authority

Permit Application No. 93938/PSD-TX-1244

Page 2 of 2

Regulated Pollutant CO_2e

	PROJECT DATE[2]	EMISSION UNIT AT WHICH REDUCTION OCCURED[3] FIN	EPN	PERMIT NO.	PROJECT NAME OR ACTIVITY	A ALLOWABLE EMISSIONS AFTER THE ACTIVITY[4] (tons/year)	B ACTUAL EMISSIONS PRIOR TO THE ACTIVITY[4] (tons/year)	C (tons/yr) DIFFERENCE (A-B)[5]	CREDITABLE DECREASE OR INCREASE[6]	REASON CODE[7]
1	01/01/2014		Stack 1	45605	Shut Down Boiler	0	577,010	-577,010	-577,010	e1a
2	01/01/2014	CTG1	U1-STK	93938	Start Up New Unit	1,031,248	0	1,031,248	1,031,248	
3	01/01/2014	CTG2	U2-STK	93938	Start Up New Unit	1,031,248	0	1,031,248	1,031,248	
4	01/01/2014	NG-FUG	NG-FUG	93938	Start Up New Unit	327	0	327	327	
5	01/01/2014	EMGEN1	EMGEN1-STK	93938	Start Up New Unit	766	0	766	766	
6	01/01/2014	FWP1	FWP1-STK	93938	Start Up New Unit	353	0	353	353	
7	01/01/2014	SF6-FUG	SF6-FUG	93938	Start Up New Unit	131	48	84	84	
8										
9										
10										
11										
12										
13										
14										
							PAGE SUBTOTAL[8]		1,487,014	
	Summary of Contemporaneous Changes						TOTAL		1,487,014	

TABLE PSD-2

1 Individual PSD-2 Tables should be used to summarize a combination of activities which may be considered a single project for each regulated pollutant.

2 Date activity occurred and is documented. Attach Table PSD-3 for each project reduction claimed which explains how the reduction is creditable.

3 Emission Point No. as designated in TNRCC Permit or Emissions Inventory.

4 All records and calculations for these values need to be available upon request. Actual emissions should be estimated as an average of the actual emissions over the two-year period prior to the Project's Activity Date.

5 Allowable (column A) - Actual (column B) for all emissions.

6 If portion of the decrease not creditable, enter creditable amount. If all decrease is creditable or if this line is an increase, enter column C again. Sum all values in this column and place in box at bottom of column.

7 For emission decreases:
Enter one of the following reason codes:
e1a - 101.29(e)1(A) Shutdowns
e1b - 101.29(e)1(B) Continuous Emission Monitors
e1c - 101.29(e)1(C) Reduction by Review
e1d - 101.29(e)1(D) Reduction by Standardized Calculation
oth - Describe on Table PSD-3.

8 Sum all values for this page.

Line 1 Page 1 of Table PSD-2

TABLE PSD-3
DESCRIPTION OF CREDITABLE REDUCTIONS

Company Name:	Lower Colorado River Authority	Contaminant:	GHG
Date Action Occurred:	Upon start up of new combustion turbines	SIC code for this plant site:	4911
Check ONE of the following:	☑ Permit No. 93938/PSD-TX-1244 ☐ Grandfathered Facility	☐ Standard Exemption	

For CREDITABLE reductions, verify each statement by checking all appropriate boxes:

☑ The reductions occurred within the contemporaneous period.[1]

☑ For each unit at the source at which the change occurred, the reductions were calculated as the allowable emissions after the change minus the actual emissions averaged over the 2-year period immediately preceding the change.

☑ The reductions occurred at the applicant's contiguous or adjacent plant site and came from units with the same 2-digit major SIC code and under the same common ownership or control.[1]

☑ The reductions have not been relied upon in issuing a previous PSD permit (including use in PSD netting).[1]

☑ The reductions have not been relied upon in issuing a nonattainment permit and the reductions have not been used as an offset[2] in a nonattainment permit or reserved in an application for use as an offset.[1]

☑ The reductions will be federally enforceable[3] by the start of construction of the proposed project and actually accomplished by the start of operation.[1]

☑ The reductions have the same qualitative significance for public health as the increase from the proposed project.[1]

Note: A reduction cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that receive a PSD permit.

For grandfathered facilities or standard exemptions:

☐ Records for this facility are available to demonstrate the actual emissions of this facility for a two-year period prior to the reduction claimed.

Please give a complete description of project's reductions and credits. Provide all emission point numbers affected by this project. Provide any explanation for above exceptions.

The existing Unit No. 1 natural gas fired utility boiler (EPN Stack 1) will be permanently shutdown following startup and commissioning period (maximum 180 days after initial startup) of the new combined cycle electric generating units (EPN U1-STK and U2-STK).

Units' Allowable: 2,519,688 tpy Units' Actual[4]: 576,466 tpy

[1] For a reduction (or increase) to be creditable these boxes must be checked. This change in emissions may not be used in netting calculations without this verification.

[2] An offset is a required reduction of equal or greater magnitude (depending on the nonattainment area) than the emissions increase from the project for which nonattainment new source review is being conducted. An offset does not refer to reductions used in nonattainment netting calculations.

[3] To ensure federal enforceability for standard exemptions at emission levels below those levels specified by the exemptions specifically in use, or by TNRCC Regulation VI, §116.211, the applicant should keep on-site a signed registration certification Form PI-8, verifying the maximum emission rate resulting from operations authorized by a standard exemption. The registration and certification must include the basis for estimated the emission rate.
To ensure federal enforceability or grandfathered emission rates, the grandfathered emission rates should be incorporated into the MAERT of an existing State permit on site or into an Agreed Order if no such permit exists.

[4] Averaged over the two-year period prior to activity.

TABLE PSD-3
DESCRIPTION OF CREDITABLE REDUCTIONS

Company Name:	Lower Colorado River Authority	Contaminant:	CO_2e
Date Action Occurred:	Upon start up of new combustion turbines	SIC code for this plant site:	4911
Check ONE of the following:	☑ Permit No. 93938/PSD-TX-1244 ☐ Grandfathered Facility	☐ Standard Exemption	

For CREDITABLE reductions, verify each statement by checking all appropriate boxes:

☑ The reductions occurred within the contemporaneous period.[1]

☑ For each unit at the source at which the change occurred, the reductions were calculated as the allowable emissions after the change minus the actual emissions averaged over the 2-year period immediately preceding the change.

☑ The reductions occurred at the applicant's contiguous or adjacent plant site and came from units with the same 2-digit major SIC code and under the same common ownership or control.[1]

☑ The reductions have not been relied upon in issuing a previous PSD permit (including use in PSD netting).[1]

☑ The reductions have not been relied upon in issuing a nonattainment permit and the reductions have not been used as an offset[2] in a nonattainment permit or reserved in an application for use as an offset.[1]

☑ The reductions will be federally enforceable[3] by the start of construction of the proposed project and actually accomplished by the start of operation.[1]

☑ The reductions have the same qualitative significance for public health as the increase from the proposed project.[1]

Note: A reduction cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that receive a PSD permit.

For grandfathered facilities or standard exemptions:

☐ Records for this facility are available to demonstrate the actual emissions of this facility for a two-year period prior to the reduction claimed.

Please give a complete description of project's reductions and credits. Provide all emission point numbers affected by this project. Provide any explanation for above exceptions.

The existing Unit No. 1 natural gas fired utility boiler (EPN Stack 1) will be permanently shutdown following startup and commissioning period (maximum 180 days after initial startup) of the new combined cycle electric generating units (EPN U1-STK and U2-STK).

Units' Allowable: 2,520,232 tpy Units' Actual[4]: 577,010 tpy

[1] For a reduction (or increase) to be creditable these boxes must be checked. This change in emissions may not be used in netting calculations without this verification.

[2] An offset is a required reduction of equal or greater magnitude (depending on the nonattainment area) than the emissions increase from the project for which nonattainment new source review is being conducted. An offset does not refer to reductions used in nonattainment netting calculations.

[3] To ensure federal enforceability for standard exemptions at emission levels below those levels specified by the exemptions specifically in use, or by TNRCC Regulation VI, §116.211, the applicant should keep on-site a signed registration certification Form PI-8, verifying the maximum emission rate resulting from operations authorized by a standard exemption. The registration and certification must include the basis for estimated the emission rate.
To ensure federal enforceability or grandfathered emission rates, the grandfathered emission rates should be incorporated into the MAERT of an existing State permit on site or into an Agreed Order if no such permit exists.

[4] Averaged over the two-year period prior to activity.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD rules define BACT 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 [the] 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.[16]

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.[17] 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. 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:

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.

[16] 40 C.F.R. § 52.21(b)(12.)

[17] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

Step 4: Evaluate most effective controls and document results.
Step 5: Select the BACT.

5.1 BACT FOR COMBINED CYCLE COMBUSTION TURBINES

5.1.1 Step 1: Identify All Available Control Technologies

5.1.1.1 Inherently Lower-Emitting Processes/Practices/Designs

LCRA performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators 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 Russell City Energy Center for a 612 MW natural gas fired combined cycle power plant to be located in Hayward, California. The Russell City Energy Center project included two Siemens-Westinghouse 501FD3 combustion turbines. That analysis determined that BACT for GHG emissions was maintenance of the high energy efficiency that is inherent with natural gas fired combined cycle power plants. A GHG BACT permit condition was established which set an efficiency limit (also referred to as heat rate) of 7,730 Btu/kWh measured during baseload conditions – a heat rate appropriate for that particular combination of gas turbine, heat recovery steam generator, and steam turbine models. The 7,730 Btu/kWh heat rate was based on a design base rate with factors added to account for a design margin and degradation between major overhauls.

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators is presented below.

5.1.1.1.1 Use of Combined Cycle Power Generation Technology

The LCRA's resource planning efforts support the replacement of the existing natural gas fired gas steam generating unit at the Ferguson Plant with a modern natural gas fueled facility. When selecting a technology for the installation of new power generation, there is an array of variables to consider. One aspect considered is the overall plant efficiency that would result from employing a particular technology.

The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle design. For fossil fuel technologies, efficiency ranges from approximately 30-50% (higher heating value [HHV]). A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 35% (HHV), while a modern F-Class natural gas fired combined cycle unit operating under optimal conditions has a baseload efficiency of approximately 50% (HHV).

The major components incorporated into a combined cycle unit are a combustion turbine, a heat recovery steam generator (HRSG), and a steam turbine. Combined cycle units operate based on a combination of two thermodynamic cycles. Typically, these are the Brayton and the Rankine cycles. A combustion turbine operates on the Brayton cycle, and the bottoming cycle, including the HRSG and steam turbine, operates on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined cycle plants.

5.1.1.1.2 Combustion Turbine Energy Efficiency Processes, Practices, and Designs

A combustion turbine constitutes three main components (i.e., compressor, combustor, and turbine) and operates on the thermodynamic Brayton cycle. There are four stages associated with the Brayton cycle, which are adiabatic compression within the compressor section, constant pressure heat addition within the combustion section, adiabatic expansion in the turbine section, and constant pressure heat rejection to a heat sink. A number of factors influence the overall efficiency of a combustion turbine, but the overriding factor is the efficiency of these three components. The combustion turbines proposed for this project are modern F-Class machines. These turbines are of advanced design with high-efficiency compressors, combustors, and turbines.

Compressor
The compressor for these F-Class machines is a high-efficiency axial compressor. The compression ratio of this type of compressor is approximately 16:1 to 18:1. The efficiency of the Brayton cycle, and therefore the combustion turbine, is improved with the increase in compression ratio. To obtain the higher compression ratios, the F-Class machines being considered for this project have 18-19 stages of compression, with a minimum of one variable inlet guide vane for exhaust gas temperature control to allow for efficient cycle performance for part load operation. The compressor blades and vanes are designed to maximize efficiency of the compressor. The blades and vanes on these modern turbines are typically designed using the latest in 3-D computer-aided technology, which allows for analysis of the air flow through the compressor to achieve the highest efficiency possible. Finally, the air is directed into the compressor through the bell mouth. The design of the compressor inlet is important to reduce the inlet pressure loss and improve the overall combustion turbine efficiency.

Combustor
The high-efficiency combustors for modern F-Class machines are designated as low-NO_X emitting. These combustors have been designed to accommodate efficient combustion along with minimization of thermal NO_X formation. The combustors for the machines being considered for this project are can-annular type. These combustors utilize a pre-mix of fuel and air in combination with multiple stages of combustion for efficient low-NO_X combustion. An increase in combustor firing temperature improves the overall efficiency of the combustion turbine. The F-Class machine has increased firing temperatures greater than 2,400°F.

Turbine
The third primary component within the combustion turbine is the turbine itself. The turbine converts the hot combustion gases into shaft power, which produces electricity through the

generator. F-Class turbines are designed with high-efficiency blades made of advanced materials with thermal barrier coatings and advanced cooling. This is necessary to allow the increased combustor firing temperatures for improved efficiency. Additionally, similar to the compressor, the turbine is modeled using 3-D computer-aided techniques to enhance the overall efficiency of the machine. Turbine clearances are also an important design aspect of the machine, and are designed and maintained as tight as possible to minimize leakage past the blades thereby improving the efficiency. Finally, the exhaust is directed out of the machine to avoid pressure drops that reduce the overall efficiency.

In addition to the high-efficiency primary components of the turbine, there are a number of other design features employed within the combustion turbine that can improve the overall efficiency of the machine. These additional features include those summarized below.

Inlet Evaporative Cooling

A combustion turbine's efficiency is affected by the amount of air mass passing through the machine. The amount of air mass is directly related to the inlet air temperature. As the inlet air temperature increases, the air density decreases, and the amount of air mass entering the combustion turbine decreases. This results in less flow through the turbine, which lowers the power generated and the turbine's efficiency. If the inlet air temperature is lowered, the density of the air increases, and the mass flow through the combustion turbine increases. As the mass flow through the combustion turbine increases, more power is generated and the turbine's efficiency increases.

In order to decrease combustion turbine inlet air temperature on warm ambient temperature days, inlet evaporative coolers can be used. The evaporative coolers are located in the inlet air duct of the turbine. The evaporative coolers use water to cool the inlet air. The drier inlet air passes through the evaporative cooler membrane, which is saturated with water. The water in the membrane is evaporated into the air as it passes through the membrane, increasing its humidity level, lowering its temperature, and increasing its density. This evaporation process increases the amount of air mass flowing through the turbine, increasing the power generated and the turbine's efficiency.

Periodic Burner Tuning

Modern F-Class combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Reduction in Heat Loss
Modern F-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. As discussed previously, the higher the combustion firing temperature the higher the combustion turbine's efficiency. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls
Modern F-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

Hydrogen Cooled Combustion Turbine Generator
Hydrogen will be used to cool the generators as opposed to air. Hydrogen has better thermal characteristics and a lower density which create a lower level of electrical losses and a corresponding higher efficiency.

5.1.1.1.3 Heat Recovery Steam Generator Energy Efficiency Processes, Practices, and Designs

The HRSGs take waste heat from the corresponding combustion turbine exhaust gas and converts it to steam. The modern F-Class combustion turbine-based combined cycle HRSG is generally a horizontal natural circulation drum-type heat exchanger designed with three pressure levels of steam generation, reheat, split superheater sections with interstage attemperation, post-combustion emissions control equipment, and condensate recirculation. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which maximizes plant efficiency.

Heat Exchanger Design Considerations
HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum-type configuration, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the

heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections employ recirculation systems to minimize cold-end corrosion, and stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is off line.

Insulation
HRSGs take waste heat from the combustion turbine exhaust gas and convert it to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For F-Class combustion turbines, these temperatures can approach 1,200°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the surroundings, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Minimizing Fouling of Heat Exchange Surfaces
HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, periodic cleaning of the tubes during outages is performed at least every eighteen months. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks
As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined cycle facility has just a few locations where steam is 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 HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Additionally, power plant operators are concerned with overall efficiency of their facilities. Therefore, steam leaks are repaired as soon as possible to maintain facility performance. Minimization of vented steam and repair of steam leaks will be performed for this project.

5.1.1.1.4 Steam Turbine Energy Efficiency Processes, Practices, and Designs

The steam turbine for this project will be a modern, high-efficiency, reheat, condensing unit. Steam turbines have been in operation for over a century, and are generally classified as impulse or reaction. However, most modern turbines employ both impulse and reaction blading. The overall efficiency of the unit is affected by a number of items, including the inlet steam conditions, the exhaust steam conditions, the blading design, 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. To achieve the higher temperatures, reheat cycles are employed. This is necessary to minimize the moisture content of 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. For a modern combined cycle facility, the high-pressure inlet and intermediate-pressure inlet steam temperatures typically are 1,050°F and above, and the high-pressure steam turbine inlet pressure is typically in the range of 1,800-2,400 psig.

Use of Exhaust Steam Condenser
Steam turbine efficiency is also improved by lowering the exhaust steam conditions of the unit. The lower the exhaust pressure, the higher the overall turbine efficiency. For high-efficiency units, the exhaust steam is saturated under vacuum conditions. This is accomplished by the use of a condenser. 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 increases 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 is more efficient.

Efficient Blading Design
Blading design also affects the overall efficiency of the turbine. As noted earlier, steam turbines have been used to generate power for over a century, and are either impulse or reaction design. The blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Additionally, 3-D computer-aided design technology is also employed to provide the highest efficiency blade design. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance.

Turbine seals are also important in the overall performance of the steam turbine. The high-pressure steam will leak to the atmosphere along the turbine shaft, as well as bypass the turbine stages if sealing is not employed. The steam turbine designers have multiple steam seal designs to obtain the highest efficiency from the steam turbine.

Efficient Steam Turbine Generator Design
The steam turbine generator is also a key element in the overall performance of the steam turbine. 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. The steam turbine for this project will

either be totally enclosed water to air-cooled or hydrogen-cooled. These cooling methods allow for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine.

5.1.1.1.5 Plant-wide Energy Efficiency Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- **Fuel gas preheating** – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. For the F-Class combustion turbine based combined cycle, the fuel gas is generally heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.
- **Cooling water source** – There are several sources for providing cooling water to the condenser. The most efficient source is generally through a river, lake, or ocean, typically referred to as once-through cooling. Additionally, a closed-loop design can be used, which includes a cooling tower to cool the water. Closed-loop designs are either natural circulation or forced circulation. Both natural circulation and forced circulation designs require higher cooling water pump heads; therefore, increasing the pump's power consumption and reducing overall plant efficiency. Additionally, to provide the forced circulation, fans are used for the forced circulation designs, which consume additional auxiliary power and reduce the plant's efficiency. A once-through system using water from Lake LBJ will be used for this project.
- **Drain operation** – Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam circuits for operation (i.e., operation drains). Operation drains are generally controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- **Multiple combustion turbine/HRSG trains** – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation.
- **Boiler feed pump fluid drives** – The boiler feed pumps are used as the means to impart high pressure on the working fluid. The pumps require considerable power. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives can be employed. For this project, fluid drives are being used to minimize power consumption at part-load, improving the facility's overall efficiency.

- **Lighting** – Plant lighting is required for safe operation of the facility. The plant lighting can consume a considerable amount of power. For this project, high-efficiency lighting, including Light Emitting Diode (LED) type lighting, will be used to minimize auxiliary power consumption.
- **Steam turbine bypass** – A steam turbine bypass system will be used for this project. The steam turbine bypass directs the steam being generated in the HRSG to the condenser during startup and trip conditions. This is performed to conserve the cycle water, avoiding the need for large amounts of makeup water.

5.1.1.2 Add-On Controls

In addition to 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 natural gas combustion in the proposed project's gas turbines and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate 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. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges:

> ...In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries... Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output...[18]

The DOE-NETL adds:

> ...Separating CO_2 from flue gas streams is challenging for several reasons:

[18] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html (last visited Mar. 8, 2011).

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems 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...[19]

If CO_2 capture can be achieved at a power plant, it will need to be routed to a geologic formation capable of long-term storage. Due to the volume of CO_2 generated by the proposed project, the captured gas would need to be transported to a potential storage site via a pipeline. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

> "...The majority of geologic formations considered for CO_2 storage, deep saline or depleted oil and gas reservoirs, are layers of porous rock underground that are "capped" by a layer or multiple layers of non-porous rock above them. Sequestration practitioners drill a well down into the porous rock and inject pressurized CO_2. Under high pressure, CO_2 turns to liquid and can move through a formation as a fluid. Once injected, the liquid CO_2 tends to be buoyant and will flow upward until it encounters a barrier of non-porous rock, which can trap the CO_2 and prevent further upward migration. Coal seams are another formation considered a viable option for geologic storage, and their storage process is a slightly different. When CO_2 is injected into the formation, it is adsorbed onto the coal surfaces, and methane gas is released and produced in adjacent wells.
>
> There are other mechanisms for CO_2 trapping as well: CO_2 molecules can dissolve in brine; react with minerals to form solid carbonates; or adsorb in the pores of the porous rock. The degree to which a specific underground formation is amenable to CO_2 storage can be difficult to discern..."[20]

5.1.2 Step 2: Eliminate Technically Infeasible Options

In this section, LCRA addresses the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine/HRSG trains. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

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[19] *Id.*

[20] DOE-NETL, *Carbon Sequestration: Storage*, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html (last visited Mar. 8, 2011).

5.1.2.1 CO_2 Capture and Compression

Though amine absorption technology has been applied for CO_2 capture to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is not yet commercially available for power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. 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."[21]

5.1.2.2 CO_2 Transport

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. A map showing existing CO_2 pipelines and potential geologic storage sites in Texas is attached at the end of this section.[22] Based on the map, currently there are no existing pipelines that could transport the CO_2 stream from the proposed plant to potential storage facilities. The closest site with recognized potential for geological storage of CO_2 is over 85 miles from the proposed project and the closest site with some demonstrated capacity for geological storage of CO_2 (i.e., the SACROC site in Scurry County) is over 210 miles away. Therefore, 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 a potential storage facility, thereby making CCS infeasible for the project.

5.1.2.3 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

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

[22] 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/environqlty/co2seq/pubs_presentations/Hovorka-%20for%20posting%20new%206-8/New%20Developments%20%96%20Solved%20and%20Unsolved%20Questions_TCEQ%202008.ppt

would still depend on the availability of a sequestration site. Potential storage sites, including enhanced oil recovery (EOR) sites and saline formations exist in Texas, but the closest site with recognized potential for geological storage of CO_2 is over 85 miles from the proposed project and the closest site with a some demonstrated capacity for geological storage of CO_2 (i.e., the SACROC site in Scurry County) is over 210 miles away, thereby making CCS infeasible for the project.

Additionally, even if it is assumed that CO_2 could be transported economically to a sequestration site, there are potential environmental impacts that would still require assessment before CCS technology can be considered feasible. These 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,[23] and
- Potential effects on wildlife.

These issues are beginning to be assessed in field demonstrations, but have not yet been fully evaluated for full-scale commercial deployment.

Based on the reasons provided above, LCRA has eliminated CCS technology from further consideration as a potential feasible control technology for purposes of this BACT analysis.

5.1.3 Step 3: Rank Remaining Control Technologies

Since 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.

5.1.4 Step 4: Evaluate Most Effective Controls and Document Results

Since 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. Since the Carbon Capture and Storage 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.

[23] *Id.*

5.1.5 Step 5: Select BACT

LCRA proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed combined cycle combustion turbines:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs
    - Efficient turbine compressor design
    - Efficient turbine combustor design
    - Efficient turbine blade design
    - Turbine inlet air cooling
    - Periodic turbine burner tuning
    - Reduction in heat loss
    - Instrumentation and controls
    - Hydrogen cooled combustion turbine generator
- HRSG Energy Efficiency Processes, Practices, and Designs
    - Efficient heat exchanger design
    - Insulation of HRSG
    - Minimizing Fouling of heat exchange surfaces
    - Minimizing vented steam and repair of steam leaks
- Steam Turbine Energy Efficiency Processes, Practices, and Designs
    - Use of Reheat Cycles
    - Use of Exhaust Steam Condenser
    - Efficient Blading Design
    - Efficient Generator Design
- Plant-wide Energy Efficiency Processes, Practices, and Designs
    - Fuel gas preheating
    - Once-through cooling water design
    - Drain operation
    - Multiple combustion turbine/HRSG trains
    - Boiler feed pump fluid drive design
    - Efficient lighting
    - Steam turbine bypass

LCRA proposes an output based GHG BACT limit of 0.459 ton CO_2e/MWhr (net) BACT on a 12-month rolling average. This BACT limit is calculated based on an average heat rate for the proposed plant (two combined cycle gas turbine generators plus one steam turbine generator) of 7,720 Btu/kWh (net basis). This limit was determined based on running each unit at 50% load, vendor heat rate guarantees at 50% load conditions, ambient temperature variability and limitations associated with the proposed plant design, as well as a 5% degradation over time. For comparison purposes, the existing 440 MW natural gas fired power boiler, which is being replaced by the proposed combined cycle units, currently achieves a net heat rate under current operating conditions of approximately 11,000 Btu/kWh.

5.2 BACT FOR EMERGENCY ENGINES

The proposed project will include installation of a new, high efficiency, fire pump engine and emergency generator which will replace existing thirty six year old 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.[24] 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 performance of routine maintenance is proposed as BACT for GHG emissions.

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. One technology is the use of 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.*[25]

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.[26] 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

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

[25] 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.

[26] *Id.* at 28 – 29.

superior in performance to the air and oil insulated equipment which was 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."

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

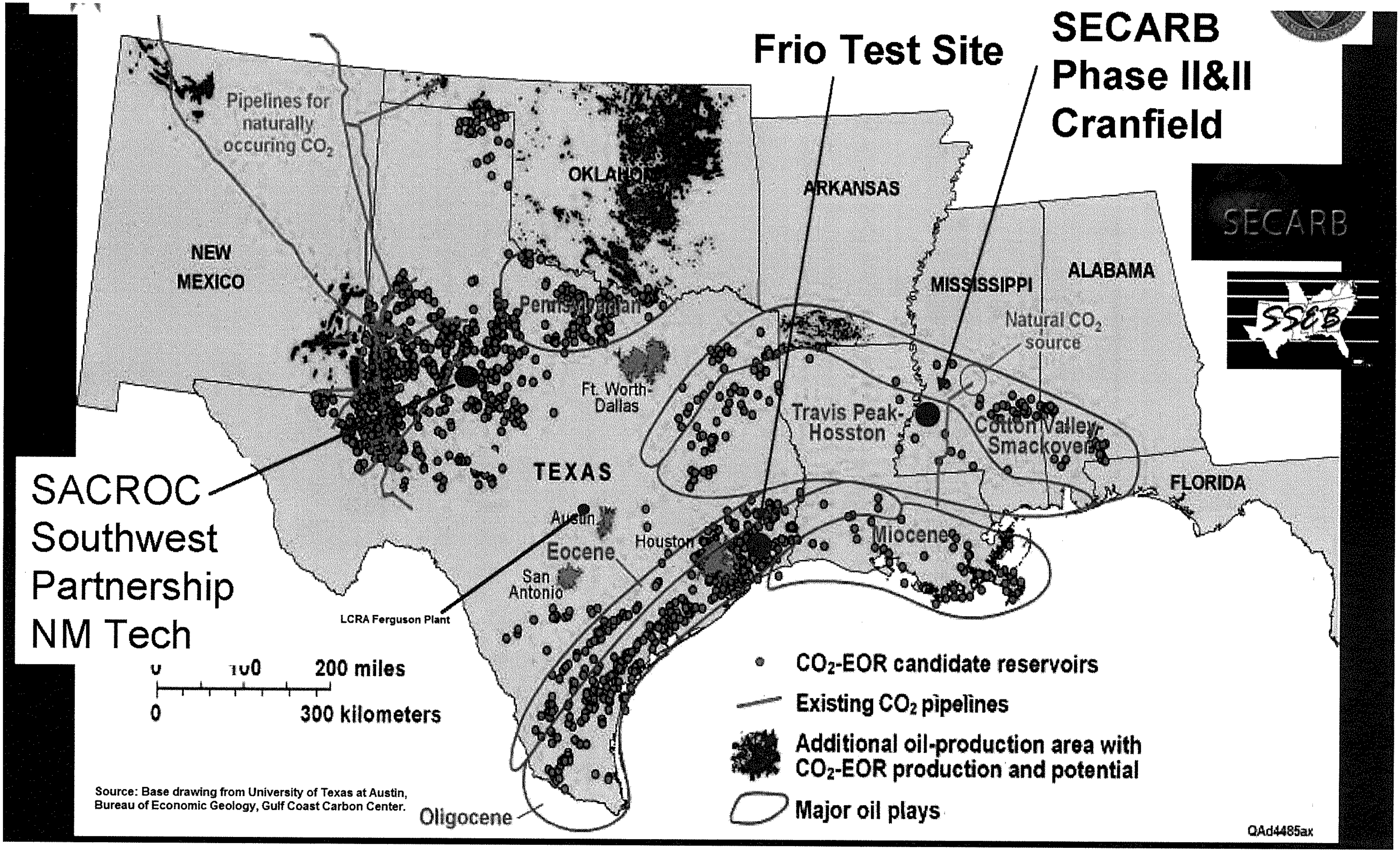
Since the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible, energy, environmental, or economic impacts were not addressed in this analysis.

5.3.5 Step 5: Select BACT

Based on this top-down analysis, LCRA 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 Institute (ANSI) C37.013 standard for high voltage circuit breakers.[27] The proposed circuit breakers in the switchyard and 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.

LCRA will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[28] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

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



Frio Test Site
SECARB
Phase II&II
Cranfield
SECARB
SSEB
Pipelines for naturally occuring CO_2
NEW MEXICO
OKLAHOMA
ARKANSAS
MISSISSIPPI
ALABAMA
FLORIDA
TEXAS
Pennsylvanian
Ft. Worth-Dallas
Travis Peak-Hosston
Natural CO_2 source
Cotton Valley-Smackover
Austin
Houston
Eocene
San Antonio
Miocene
Oligocene
LCRA Ferguson Plant
SACROC
Southwest
Partnership
NM Tech
0 100 200 miles
0 300 kilometers
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.
QAd4485ax

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.[29]

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."*[30]

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 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*

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

[30] *Id.* at 49.

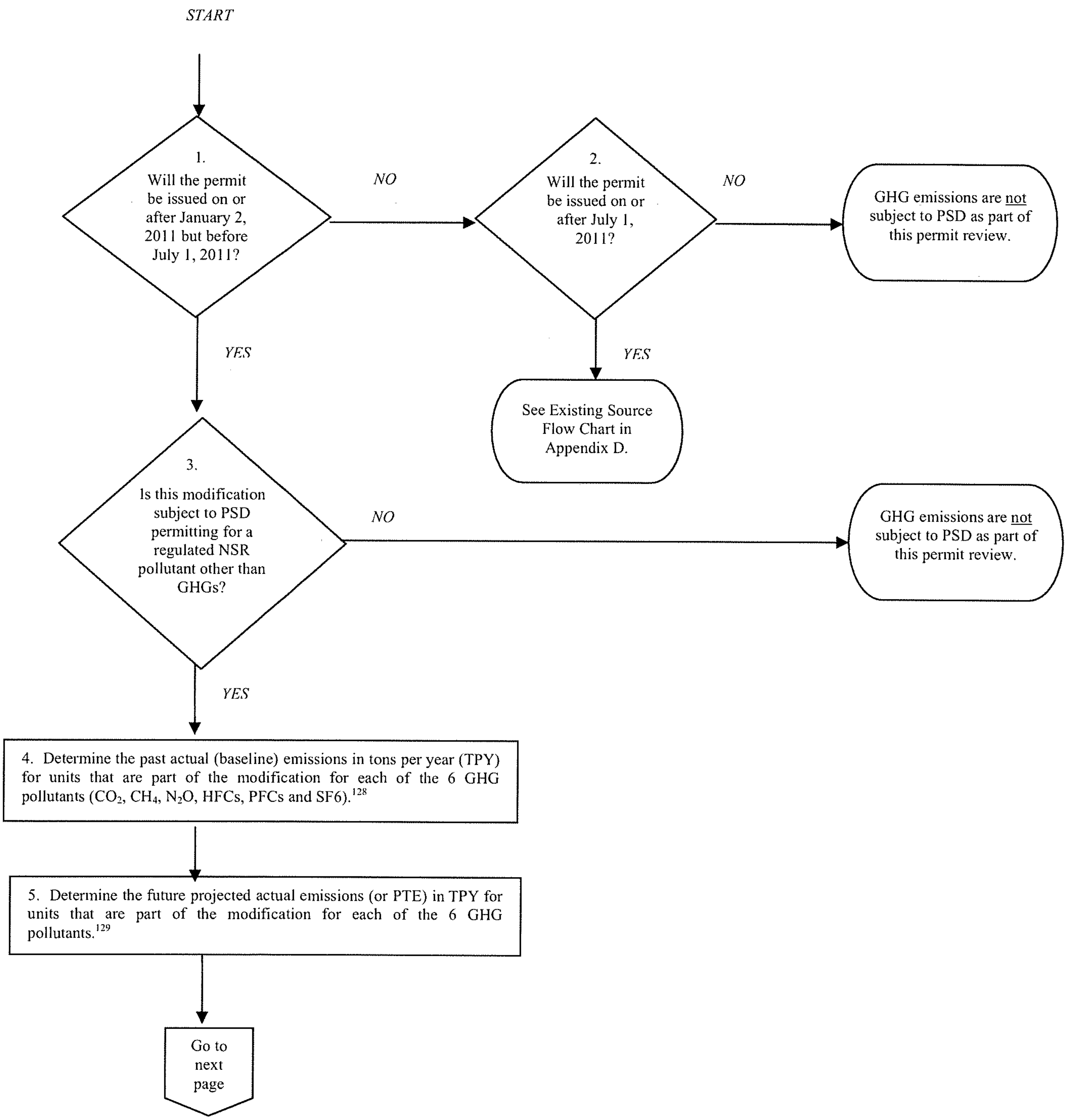
current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts 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.[31]"

[31] *Id.*

APPENDIX A

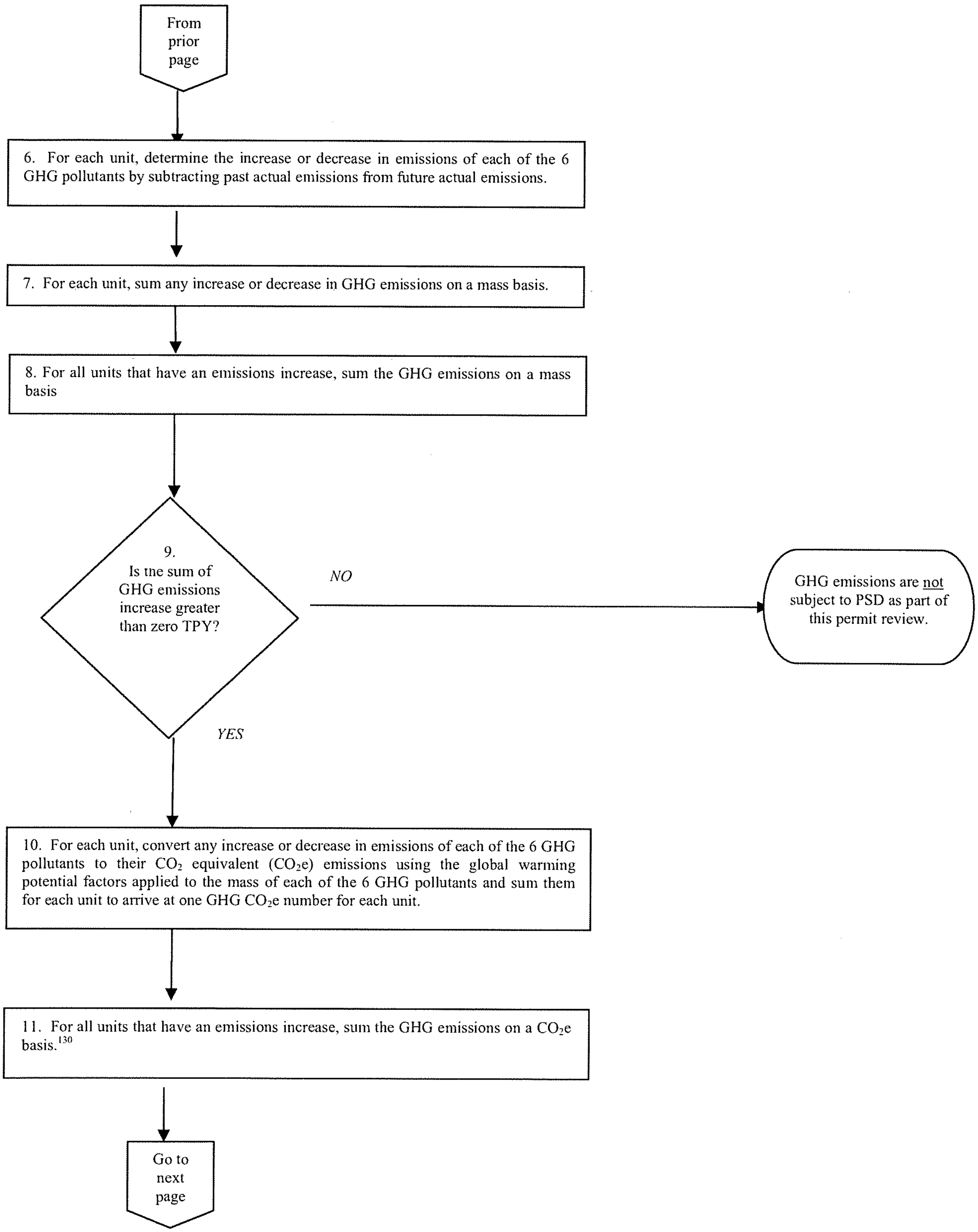
GHG PSD APPLICABILITY FLOWCHART – EXISTING SOURCES

Appendix C. GHG Applicability Flow Chart – Existing Sources (January 2, 2011, through June 30, 2011)

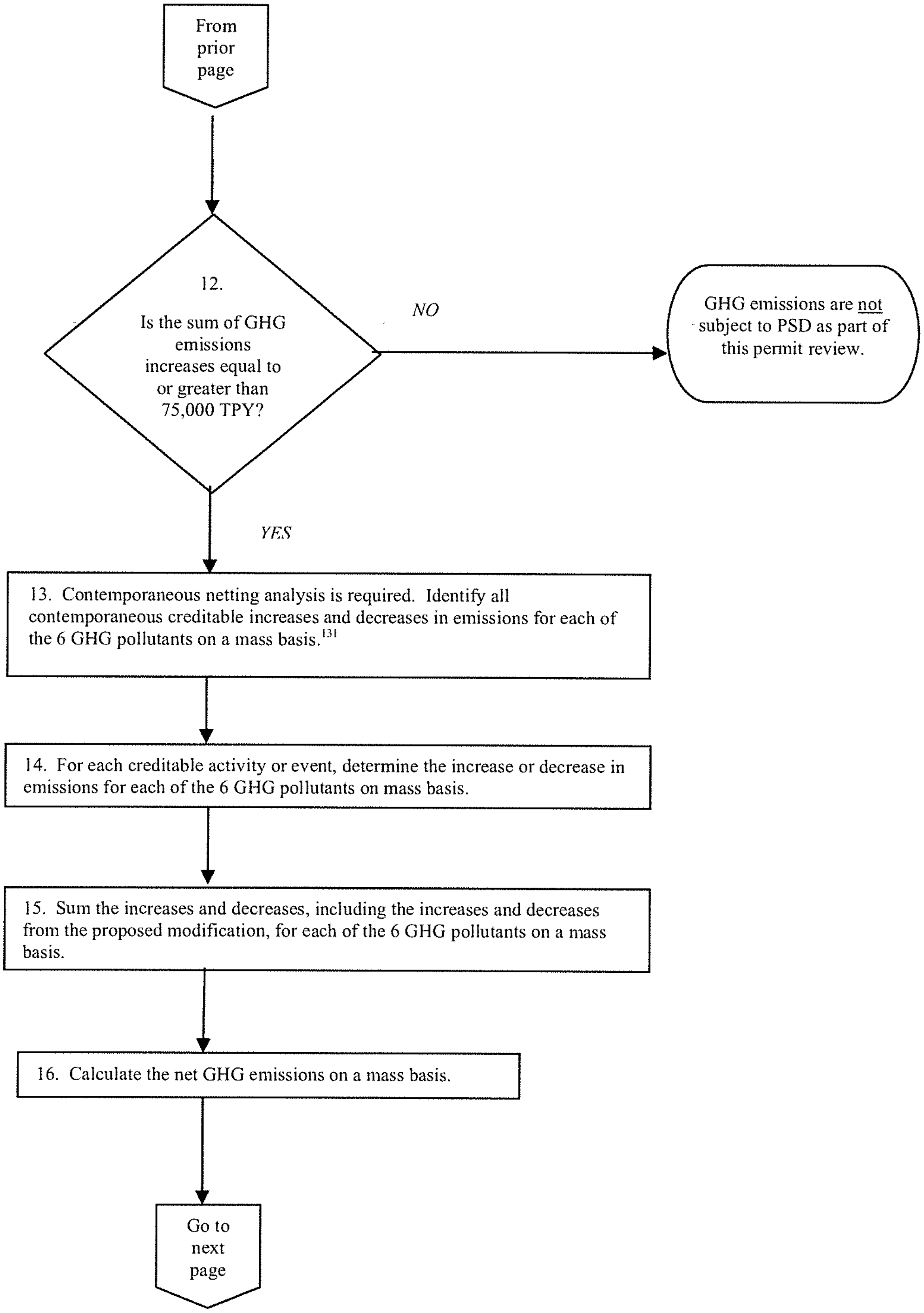


[128] For new units, the past actual emissions are zero.

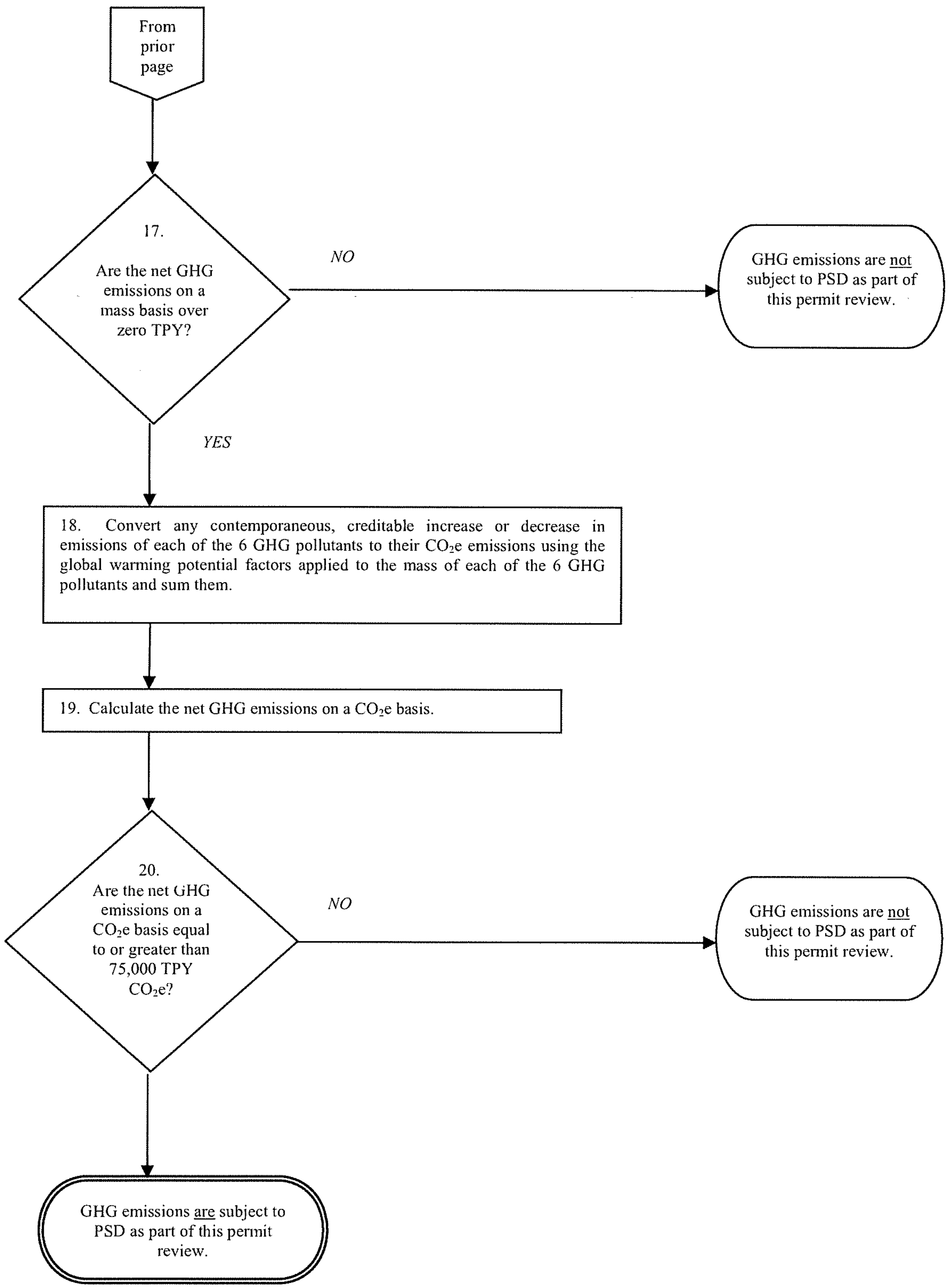
[129] For new units that are not like-kind replacements, future actual emissions are always the PTE.



[130] Emission decreases are not considered at this step.



[131] Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.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17.
Are the net GHG emissions on a mass basis over zero TPY?
NO
GHG emissions are not subject to PSD as part of this permit review.
YES
18. Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants to their CO_2e emissions using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them.
19. Calculate the net GHG emissions on a CO_2e basis.
20.
Are the net GHG emissions on a CO_2e basis equal to or greater than 75,000 TPY CO_2e?
NO
GHG emissions are not subject to PSD as part of this permit review.
GHG emissions are subject to PSD as part of this permit review.