TENASKA® BROWNSVILLE PARTNERS, LLC

1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446
402-691-9500
Fax: 402-691-9526

February 14, 2013

Mr. Jeffrey Robinson
Permit Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas TX 75202-2733

Via Overnight Courier

RE: Application for PSD GHG Permit
Tenaska Brownsville Partners, LLC – Tenaska Brownsville Generating Station
TCEQ Customer Reference Number (CN) 604252627
TCEQ Regulated Entity Number (RN) 106579600

Dear Mr. Robinson:

Tenaska Brownsville Partners, LLC is submitting the attached Prevention of Significant Deterioration (PSD) permit application for greenhouse gases for the proposed Tenaska Brownsville Generating Station to be located in Brownsville, Texas.

If you have any questions or require additional information, please feel free to contact me at (402) 938-1661 or lcarlson@tenaska.com.

Sincerely,

TENASKA BROWNSVILLE PARTNERS, LLC
a Delaware limited liability company
By: Tenaska Brownsville I, LLC, Its Manager

By: Larry G. Carlson, QEP
Director, Air Programs

Enclosure

cc: Air Permits Initial Review Team (APIRT), TCEQ Austin (without enclosure)

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

Tenaska Brownsville Partners, LLC
Tenaska Brownsville Generating Station

Prepared by

TENASKA INC.
Larry G. Carlson, QEP - Director of Air Programs

TRINITY CONSULTANTS

Paul Greywall, P.E. – Director
Melissa Dakas – Managing Consultant
Latha Kambham, Ph.D. – Senior Consultant
Chakri Tennety - Senior Consultant
Lele Bao - Consultant

February 2013

Project 124401.0126

Environmental solutions delivered uncommonly well

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Tenaska Brownsville Partners, LLC (Tenaska) proposes to construct a greenfield electric power generation facility in Brownsville, Cameron County, Texas (Tenaska Brownsville Generating Station).

The primary Standard Industrial Classification code of the proposed Tenaska Brownsville Generating Station (Brownsville Generating Station) is 4911 (Electric Services). Tenaska has been assigned a Texas Commission on Environmental Quality (TCEQ) Customer Reference Number (CN) 604252627 and the Brownsville Generating Station has been assigned a TCEQ Regulated Entity Number (RN) 106579600.

Cameron County is currently an attainment or unclassified area for all criteria pollutants.[1] Based on the location of the facility, the Brownsville Generating Station will not be subject to nonattainment new source review (NNSR).

1.1 PROPOSED PROJECT

Tenaska is proposing to permit two project designs: a 1-on-1 or a 2-on-1 combined cycle combustion turbine (CCCT) configuration. The Brownsville Generating Station will be designed to have an estimated nominal power generation summer condition output capacity of approximately 400 megawatts (MW) for the 1-on-1 configuration or 800 MW for the 2-on-1 configuration. Tenaska proposes to install Mitsubishi 501GAC combustion turbine generator(s) which will be equipped with a heat recovery steam generator (HRSG) with supplemental 250 million British thermal units per hour (MMBtu/hr, higher heating value[HHV]) natural gas-fired "duct" burners. Steam from the HRSG(s) will serve a single steam turbine generator. Each combustion turbine and associated duct burner will have a common exhaust stack. Therefore, these are represented as a single emission point for each CCCT. The CCCTs will be fueled by pipeline-quality natural gas only. Selective catalytic reduction (SCR) will be employed as the Best Available Control Technology (BACT) for emissions of nitrogen oxides (NO_X) from the CCCTs. Oxidation Catalyst will be employed as the BACT for emissions of carbon monoxide (CO) and volatile organic compounds (VOC) from the CCCTs. Construction of the proposed plant is projected to commence in May 2014 and the plant is proposed to be operational in June 2016.

The proposed Brownsville Generating Station will include the following emission sources:

- One (1) or two (2) Natural Gas-fired Combustion Turbines with duct burners, including planned maintenance, start-up, and shutdown (MSS) activities
- One (1) Cooling Tower
- One (1) Diesel Fire Pump Engine
- One (1) Diesel Emergency Generator
- One (1) Fuel Gas Heater
- One (1) Auxiliary Boiler
- Two (2) Diesel Storage Tanks
- Fugitive emissions from fuel and ammonia piping components and SF_6 emissions circuit breakers
- Other MSS activities onsite

[1] Per 40 CFR §81.344 (Effective July 20, 2012)

Tenaska proposes to use anhydrous ammonia for the SCR system. The anhydrous ammonia will be stored in a pressurized tank and the unloading operations will be equipped with a vapor return line. Therefore, the ammonia storage tank and unloading operations are not considered as potential emission sources.

A detailed process description is included in Section 6 of this permit application.

1.2. PERMITTING CONSIDERATIONS

PSD regulations define a stationary source as a major source if it emits or has the potential to emit (PTE) either of the following:

- 250 tons per year (tpy) or more of any PSD pollutant; or
- 100 tpy or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

Fossil fuel-fired steam electric plants with heat input greater than 250 MMBtu/hr are one of the 28 PSD major facility categories. Sources on this list are also required to include fugitive emissions in determining whether the source is a "major stationary source" and therefore subject to the PSD permitting program.

The proposed Brownsville Generating Station is within a major facility category and subject to a 100 tpy threshold for classification as a PSD major source. The Brownsville Generating Station is estimated to have potential emissions in excess of 100 tpy for NO_x, CO, and VOC emissions. In addition, the greenhouse gas (GHG) emissions exceed the tailored major source PSD threshold of 100,000 tpy. Therefore, the Brownsville Generating Station will be considered a new major source with respect to the PSD program. According to EPA guidance, the "major for one, major for all" PSD policy, if a site is major for one or more criteria pollutants, then the other criteria pollutant emissions need to be compared to the Significant Emission Rates (SERs) when determining PSD applicability for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist. Based on emissions estimates for the Brownsville Generating Station, the proposed project will be PSD major for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, and GHGs.

GHG emissions for each applicable emission source were estimated based on emission limits and controls proposed as BACT, proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel). The PTE of GHGs from the proposed Brownsville Generating Station will be greater than 100,000 tpy on a CO_2e basis. A summary of the GHG emissions from the proposed project, calculated on a CO_2e basis by use of the Global Warming Potentials set forth in Table A-1 to Subpart A of 40 CFR Part 98, is shown in Table 1.2-1.

Table 1.2-1. Brownsville Generating Station- Proposed Project GHG Emissions

EPN	Emission Point Description	GHG Emission Rates (short tons per year)				
		CO_2	CH_4	N_2O	SF_6	Total CO_2e
1	Combustion Turbine 1/ Duct Burner (Normal Operations)	1,570,399.4	105.57	40.099	-	1,585,046
2	Combustion Turbine 2/ Duct Burner (Normal Operations)	1,570,399.4	105.57	40.099	-	1,585,046
4	Fire Pump Engine	31.2	1.3E-03	2.52E-04	-	31
5	Emergency Generator	155.1	6.3E-03	1.26E-03	-	156
6	Fuel Gas Heater	5,119.7	0.10	0.010	-	5,125
7	Auxiliary Boiler	23,038.6	0.43	0.044	-	23,061
12	Fugitive SF_6 Circuit Breaker Emissions	-	-	-	0.005	122
12	Components Fugitive Leak Emissions	-	1.02	-	-	21
1 and 2	CCCT MSS Emissions		3,208.80	-	-	67,385
	Total (1 on 1 Scenario)	**1,598,744.0**	**1,711.52**	**40.155**	**0.005**	**1,647,254**
	Total (2 on 1 Scenario)	**3,169,143.4**	**3421.49**	**80.254**	**0.005**	**3,265,993**

To be consistent with the reporting format in GHG Mandatory Reporting Rule, the emissions rounded as follows: CO_2 - 1 decimal place, CH_4 - 2 decimal places, N_2O - 3 decimal places, and CO_2e - rounded to nearest digit.

1.3. PERMIT APPLICATION

All required supporting documentation for the permit application is provided in the following sections. The TCEQ Form PI-1 is included in Section 2 and a TCEQ Core Data form is found in Section 3 of this application. An area map indicating the site location and a plot plan identifying the location of various emission units at the site are included in Sections 4 and 5 of the report, respectively. A project description and process flow diagram are presented in Section 6. A summary of the emission calculations and the TCEQ Table 1(a) can be found in Sections 7 and 8 of this application.

Detailed federal regulatory requirements are provided in Section 9 and discussions of Best Available Control Technology (BACT) are provided in Section 10.

2. TCEQ FORM PI-1

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

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

I. Applicant Information			
A. Company or Other Legal Name: Tenaska Brownsville Partners, LLC			
Texas Secretary of State Charter/Registration Number (if applicable):			
B. Company Official Contact Name: Jim Welniak			
Title: Vice President, Engineering			
Mailing Address: 1044 N. 115th St., Suite 400			
City: Omaha	State: NE	ZIP Code: 68154-4446	
Telephone No.: 402- 691-9500	Fax No.: 402-691-9530	E-mail Address: jwelniak@tenaska.com	
C. Technical Contact Name: Larry G. Carlson			
Title: Director, Air Programs			
Company Name: Tenaska Brownsville Partners, LLC			
Mailing Address: 1044 N. 115th St., Suite 400			
City: Omaha	State: NE	ZIP Code: 68154-4446	
Telephone No.: 402-938-1661	Fax No.: 402-691-9530	E-mail Address: lcarlson@tenaska.com	
D. Site Name: Tenaska Brownsville Generating Station			
E. Area Name/Type of Facility: Power Generating Plant			☒ Permanent ☐ Portable
F. Principal Company Product or Business:			
Principal Standard Industrial Classification Code (SIC): 4911			
Principal North American Industry Classification System (NAICS): 221112			
G. Projected Start of Construction Date: 05/01/2014			
Projected Start of Operation Date: 06/01/2016			
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):			
Street Address: NE Corner of State Hwy 550 & Old Alice Road			
City/Town: Brownsville	County: Cameron	ZIP Code: 78575	
Latitude (nearest second): 26° 1'36"N	Longitude (nearest second): 97°30'13"W		

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
J.	Core Data Form.	
	Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).	☒ YES ☐ NO
K.	Customer Reference Number (CN): 604252627	
L.	Regulated Entity Number (RN): 106579600	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C.	Number of New Jobs : Approximately 20	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
	State Senator: Eddie Lucio	District No.: 27
	State Representative: Rene O. Oliveira	District No.: 37
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested. ☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* ☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit ☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Other:	
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

III. Type of Permit Action Requested *(continued)*		
E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: N/A		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined Permit Application will be submitted per the requirements
Associated Permit No (s.): N/A –Greenfield Site		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.		
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. **No**	
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F.	List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC): See emission calculations		
Sulfur Dioxide (SO2): See emission calculations		
Carbon Monoxide (CO): See emission calculations		
Nitrogen Oxides (NOx): See emission calculations		
Particulate Matter (PM): See emission calculations		
PM 10 microns or less (PM10): See emission calculations		
PM 2.5 microns or less (PM2.5): See emission calculations		
Lead (Pb): None		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above: NH_3, H_2SO_4 Mist and $(NH_4)_2SO_4$		

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Christie Couvillion		
Title: Sr. Environmental Specialist		
Mailing Address: 1044 N. 115th St, Suite 400		
City: Omaha	State: NE	ZIP Code: 68154
B. Name of the Public Place: Brownsville Public Library – Main Branch		
Physical Address *(No P.O. Boxes)*: 2600 Central Boulevard		
City: Brownsville	County: Cameron	ZIP Code: 78520
The public place has granted authorization to place the application for public viewing and copying.		☒ YES ☐ NO
The public place has internet access available for the public.		☒ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits		
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.		
The Honorable: Carlos H. Cascos		
Mailing Address: 1100 E. Monroe St., Dancy Building, Second Floor		
City: Harlingen	State: TX	ZIP Code: 78520
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Mayor Tony Martinez		
Mailing Address: P.O. Box 911		
City: Brownsville	State: TX	ZIP Code: 78522
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

V.	**Public Notice Information *(complete if applicable) (continued)***	
C.	Concrete Batch Plants, PSD, and Nonattainment Permits	
3.	Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):		
D.	Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?		☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	Spanish	
VI.	**Small Business Classification *(Required)***	
A.	Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☐ Existing Authorizations **N/A**	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b.	☒ Table 2 (Form 10155) entitled, Material Balance	
c.	☒ Other equipment, process or control device tables	
B.	Are any schools located within 3,000 feet of this facility?	☒ YES ☐ NO

VII.	**Technical Information**		
C.	Maximum Operating Schedule:		
Hour(s):24 hrs/day	Day(s):7 days/week	Week(s):52 weeks/yr	Year(s): 8,760 hrs/year
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?		☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
E.	Does this application involve any air contaminants for which a disaster review is required?		☒ YES ☐ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?		☐ YES ☒ NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*		
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?		☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?		☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?		☒ YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?		☒ YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*		
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?		☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?		☐ YES ☒ NO

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO

X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.	

XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $75,000 (TCEQ Fee)
Paid online?	☐ YES ☒ NO
Company name on check: Tenaska Inc.	
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

XII. Delinquent Fees and Penalties

This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature

The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: Jim Welniak - Vice President, Engineering

Signature: James Welniak
Original Signature Required

Date: Feb 13, 2013

3. TCEQ CORE DATA FORM

TCEQ Use Only

TCEQ Core Data Form

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (*If other is checked please describe in space provided)*

☒ New Permit, Registration or Authorization (*Core Data Form should be submitted with the program application)*

☐ Renewal (*Core Data Form should be submitted with the renewal form)* ☐ Other

2. Attachments Describe Any Attachments: (*ex. Title V Application, Waste Transporter Application, etc.)*

☒Yes ☐No NSR Initial Permit Application

3. Customer Reference Number (*if issued)*: CN 604252627

Follow this link to search for CN or RN numbers in Central Registry**

4. Regulated Entity Reference Number (*if issued)*: RN 106579600

SECTION II: Customer Information

5. Effective Date for Customer Information Updates (mm/dd/yyyy)

6. Customer Role (Proposed or Actual) – *as it relates to the Regulated Entity listed on this form. Please check only one of the following:*

☐Owner ☐ Operator ☒ Owner & Operator
☐Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐Other: ____________

7. General Customer Information

☒ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐Change in Legal Name (Verifiable with the Texas Secretary of State) ☐ No Change**
***If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.*

8. Type of Customer:

8. Type of Customer:	☒ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other: ____________

9. Customer Legal Name (*If an individual, print last name first: ex: Doe, John)* | *If new Customer, enter previous Customer below* | *End Date:*

Tenaska Brownsville Partners, LLC

10. Mailing Address: 1044 N. 115th St, Suite 400

City	Omaha	State	NE	ZIP	68154	ZIP + 4	4446

11. Country Mailing Information (*if outside USA)*

12. E-Mail Address (*if applicable)*: lcarlson@tenaska.com

13. Telephone Number: (402) 938-1661

14. Extension or Code:

15. Fax Number (*if applicable)*: (402) 691-9530

16. Federal Tax ID (*9 digits)*: 46-134904

17. TX State Franchise Tax ID (*11 digits)*:

18. DUNS Number (*if applicable)*:

19. TX SOS Filing Number (*if applicable)*:

20. Number of Employees: ☐ 0-20 ☒ 21-100 ☐ 101-250 ☐ 251-500 ☐ 501 and higher

21. Independently Owned and Operated? ☒ Yes ☐ No

SECTION III: Regulated Entity Information

22. General Regulated Entity Information (*If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)*

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☒ Update to Regulated Entity Information ☐ No Change** (*See below)*

**If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.

23. Regulated Entity Name (*name of the site where the regulated action is taking place)*

Tenaska Brownsville Partners, LLC

24. Street Address of the Regulated Entity: (No P.O. Boxes)	NE Corner of State Hwy 550 & Old Alice Road							
	City	Brownsville	State	TX	ZIP	78575	ZIP + 4	
25. Mailing Address:	1044 N. 115th St, Suite 400							
	City	Omaha	State	NE	ZIP	68154	ZIP + 4	4446
26. E-Mail Address:	lcarlson@tenaska.com							

27. Telephone Number	28. Extension or Code	29. Fax Number (if applicable)
(402) 938-1661		(402) 691-9530

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
4911		221112	

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*

Power Generation

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	NE Corner of State Hwy 550 & Old Alice Road in Brownsville

36. Nearest City	County	State	Nearest ZIP Code
Brownsville	Cameron	TX	78575

37. Latitude (N) In Decimal:	26.026777		38. Longitude (W) In Decimal:	97.503742	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
26	1	36.40	97	30	13.47

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Industrial Hazardous Waste	☐ Municipal Solid Waste
☒ New Source Review – Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS	☐ Sludge
☐ Stormwater	☐ Title V – Air	☐ Tires	☐ Used Oil	☐ Utilities
☐ Voluntary Cleanup	☐ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:

SECTION IV: Preparer Information

40. Name:	Larry G. Carlson	41. Title:	Director, Air Programs
42. Telephone Number	**43. Ext./Code**	**44. Fax Number**	**45. E-Mail Address**
(402) 938-1661		(402) 691-9530	lcarlson@tenaska.com

SECTION V: Authorized Signature

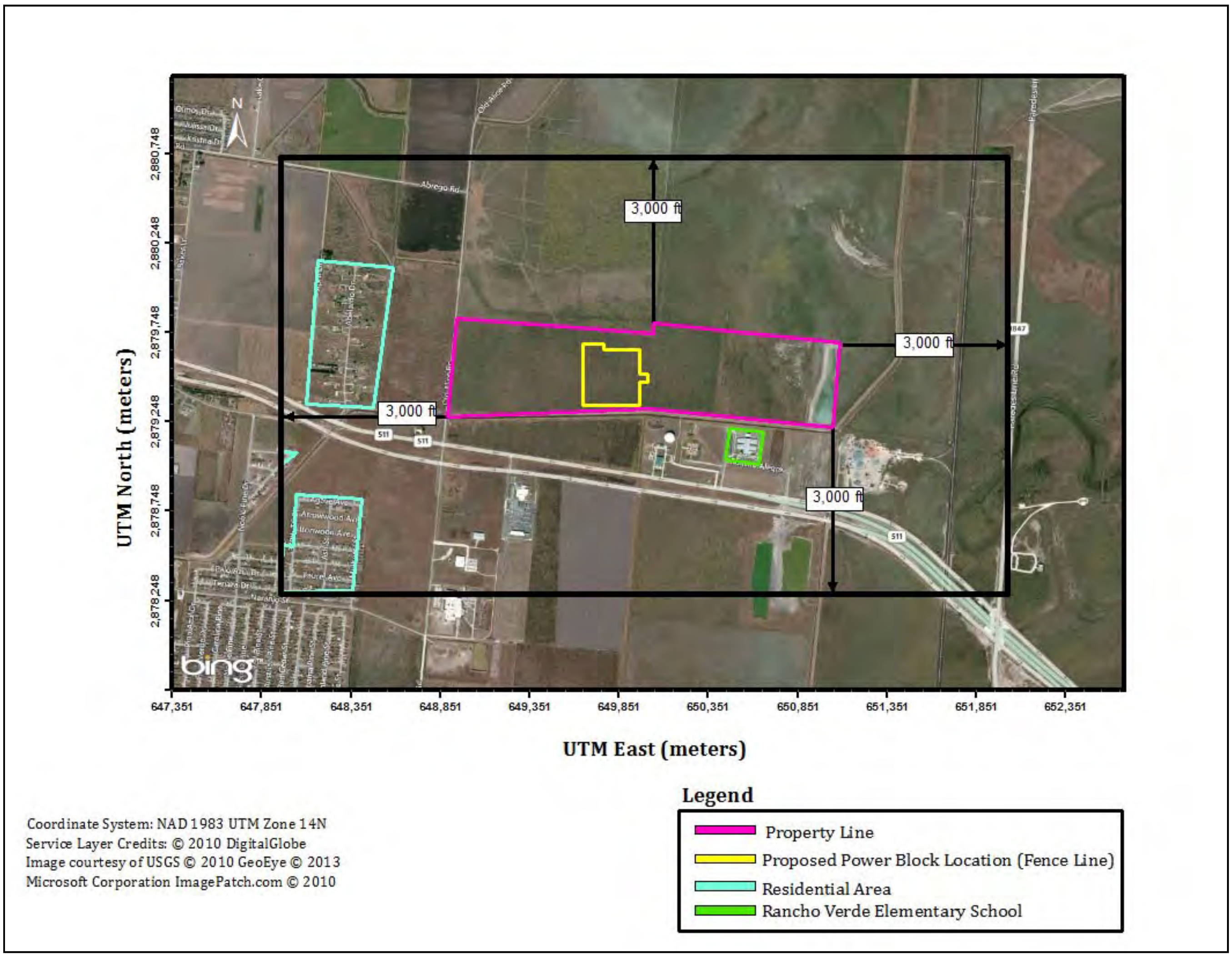
46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 9 and/or as required for the updates to the ID numbers identified in field 39.

(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Tenaska Brownsville Partners, LLC	Job Title:	Vice President, Engineering
Name (In Print):	Jim Welniak	Phone:	(402) 691-9500
Signature:	James Welniak	Date:	Feb. 13, 2013

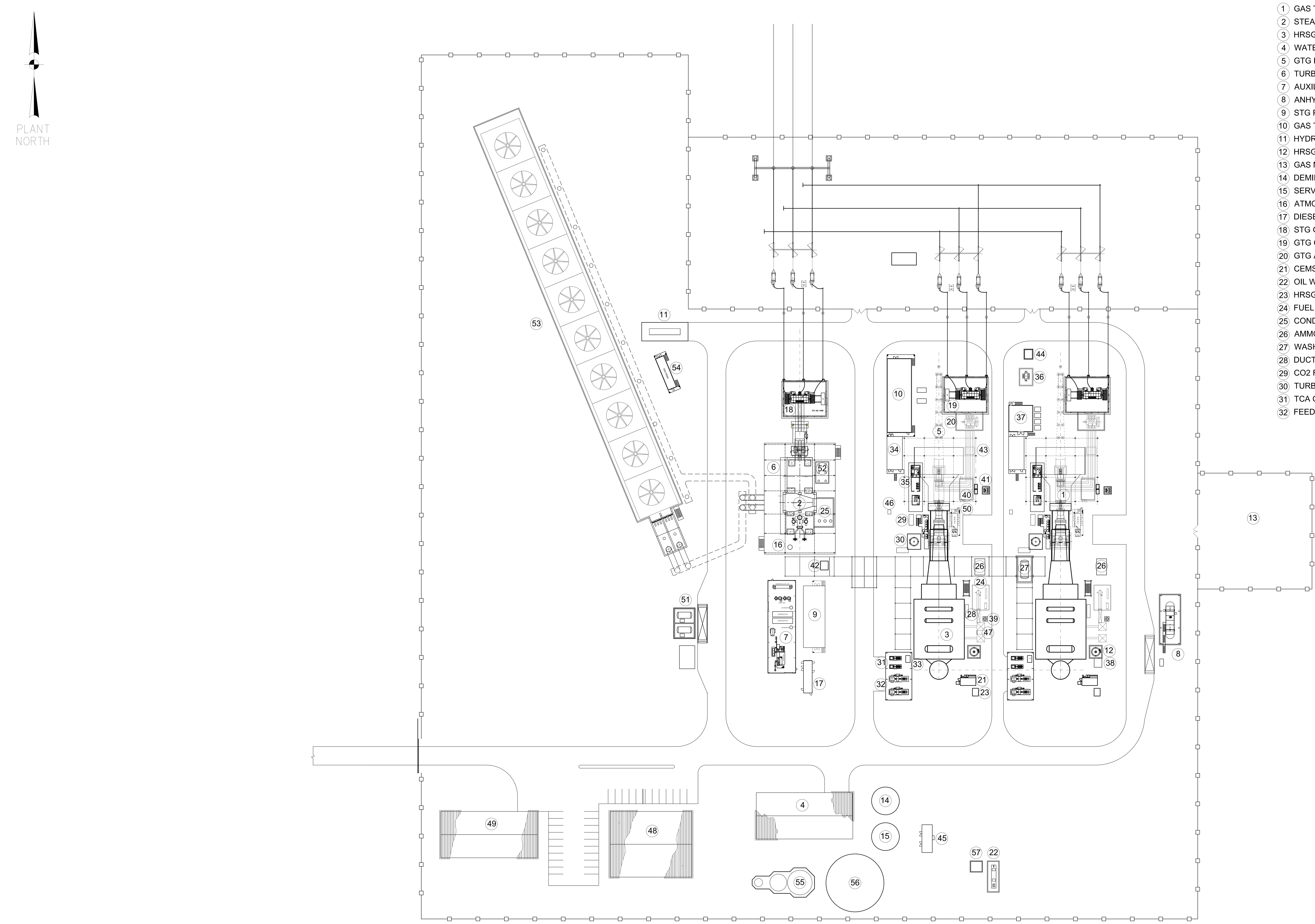
The Brownsville Generating Station will be located in Cameron County, Texas. An area map is included in this section to graphically depict the location of the facility and the power block with respect to the surrounding topography. Figure 4-1 is an area map centered on the Brownsville Generating Station that extends out at least 3,000 feet from the property line in all directions. The map depicts the property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). The image shows there is one elementary school (Rancho Verde Elementary School) within 3,000 feet of the facility boundary.

Figure 4-1 Area Map
Tenaska Brownsville Partners, LLC
Brownsville Generating Station



5. PLOT PLAN

The following figures depict the site plan for the proposed Brownsville Generating Station.



1. GAS TURBINE GENERATOR
2. STEAM TURBINE GENERATOR
3. HRSG HEAT RECOVERY STEAM GENERATOR
4. WATER TREATMENT BUILDING
5. GTG ROTOR REMOVAL SPACE
6. TURBINE OPERATING PLATFORM
7. AUXILIARY BOILER & EQUIPMENT ENCLOSURE
8. ANHYDROUS AMMONIA STORAGE
9. STG POWER DISTRIBUTION CENTER
10. GAS TURBINE POWER DISTRIBUTION CENTER
11. HYDROGEN STORAGE
12. HRSG BLOWDOWN TANKS
13. GAS METERING YARD
14. DEMINERALIZED WATER TANK
15. SERVICE / FIRE WATER TANK
16. ATMOSPHERIC DRAIN TANK
17. DIESEL GENERATOR
18. STG GSU TRANSFORMER
19. GTG GSU TRANSFORMER
20. GTG AUXILIARY TRANSFORMER
21. CEMS ENCLOSURE
22. OIL WATER SEPARATOR
23. HRSG SUMP
24. FUEL GAS HEATER & DRAIN TANK
25. CONDENSATE PUMPS
26. AMMONIA SKID
27. WASH WATER DRAIN TANK
28. DUCT BURNER MANAGEMENT SKID
29. CO2 FIRE PROTECTION TANK
30. TURBINE AIR COOLER
31. TCA COOLER PUMPS
32. FEEDWATER PUMPS
33. PHOSPHATE SKID
34. GTG ELECTRICAL CONTROL MODULE
35. GTG LUBE OIL MODULE
36. SFC TRANSFORMER
37. SFC MODULE
38. HRSG BLOWDOWN SUMP
39. FUEL GAS FILTER
40. EXCITATION MODULE
41. EXCITATION TRANSFORMER
42. STEAM TURBINE SUMP
43. GENERATOR CIRCUIT BREAKER
44. TRANSFORMER SUMP
45. FIRE PUMP ENCLOSURE
46. COMPRESSOR WASH SKID
47. SCR MAINTENANCE AREA
48. ADMINISTRATION / CONTROL BUILDING
49. WAREHOUSE BUILDING
50. GTG FUEL GAS UNIT
51. COOLING TOWER CHEMICAL STORAGE AREA
52. STG LUBE OIL SYSTEM
53. COOLING TOWER
54. COOLING TOWER POWER DISTRIBUTION SYSTEM
55. CLARIFIER
56. CLEARWELL / CLARIFIED WATER TANK
57. WASTEWATER SUMP

0 30' 60' 120' 180' 240'
1"=60'

REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REV	DATE	REVISION DESCRIPTION	BY	CHK	APPV	REFERENCE DWG NUMBER	REFERENCE DRAWINGS	REFERENCE DWG NUMBER	REFERENCE DRAWINGS
E															

FLUOR®

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CONTRACT	
DESIGNED BY	
CHECKED BY	
SUPERVISOR	APP DATE
LEAD ENGR/SPEC.	APP DATE
FLUOR	APP DATE
CLIENT	APP DATE

TENASKA
BROWNSVILLE POWER STATION

GENERAL ARRANGEMENT
SITE PLAN
2 x 1 MHI 501 GAC

SCALE	DRAWING NUMBER	REV
1"=60'		E

CAD FILE NAME Brownsville Site Plans Rev E.dwg

PLOT DATE: C:\1 Project Folders\Tenaska Brownsville\CAD\Brownsville Site Plans Rev E.dwg 01-24-13 3:26 pm Printed By: bry35542

The Brownsville Generating Station will consist of a 1-on-1 or a 2-on-1 CCCT configuration with duct burners and associated equipment including a cooling tower, a fire pump engine, an emergency generator, a fuel gas heater, an auxiliary boiler, two diesel storage tanks (one associated with the fire pump engine and the other associated with the emergency generator), and an ammonia storage and unloading system. A process flow diagram for the proposed operations is included at the end of this section. In addition, maintenance, start-up, and shutdown activities are detailed below.

6.1. COMBUSTION TURBINES

The combustion turbines at the proposed Brownsville Generating Station (Facility Identification Number [FIN]/Emission Point Number [EPN]s: 1 and 2) will be either one or two Mitsubishi's 501GAC CCCTs. The CCCTs will be fired with pipeline-quality natural gas and have an estimated nominal power generation summer condition capacity of 400 MW or 800 MW, depending upon whether one or two CCCTs are constructed.

Primary electric power production at the facility will be provided by the CCCTs. A combustion turbine operates by using ambient air as the primary working gas. Initially, air is inducted into a series of compressor stages to increase its overall potential energy. The high-pressure air exiting the compressor then passes into a low-NO_X burner unit, where it is mixed with the fuel (i.e., natural gas). The premixed working gases are then subjected to a near constant pressure combustion process. This increases the working gas temperature, further increasing potential energy. Following combustion, the working gases are expanded and cooled through a series of turbine stages. This decrease in potential energy of the working gases drives the turbine shaft. Part of the energy extracted by the rotating turbine is used to drive the compressor stages to allow for a continuous process, and the remaining energy is used to drive an electro-magnetic generator, thereby producing electricity.

Since the exhaust gases exiting the turbine blade stages are at temperatures significantly above the starting ambient conditions, they represent additional available energy. The turbine exhaust is routed to an HRSG. Each HRSG has an associated duct burner that can be used to raise the temperature of the turbine exhaust gas for additional steam generation under certain operating conditions. The duct burners operate as a natural gas diffusion flame process. Steam produced by the HRSGs is expanded through a steam turbine to drive another electro-magnetic generator, creating additional electricity. Exhaust from the steam generator is then sent to a condenser to condense the steam and reduce the water temperature for re-use in the steam cycle.

Emissions resulting from the combustion of natural gas in the CCCTs and duct burners consist mainly of criteria pollutants (i.e., NO_X, CO, SO_2, VOC, and all forms of PM), GHGs, and a small amount of hazardous air pollutants (HAPs). Emissions from each combustion turbine (CT) and HRSG duct burner unit will pass through an SCR unit before being released to the atmosphere through a common stack. There will be no bypass stack for the CT and duct burner exhaust. The SCR unit will employ ammonia and catalyst to control NO_X emissions. Oxidation catalyst will be employed upstream of the SCR catalyst for the control of CO and VOC emissions from the CTs and duct burners.

The details of the startup and shutdown (SUSD) events are provided in Section 7 of this application and in emission calculations.

6.2. FIRE PUMP ENGINE AND EMERGENCY GENERATOR

The Brownsville Generating Station will have two diesel-fired emergency engines: an emergency fire pump engine (FIN/EPN: 4) and an emergency generator (FIN/EPN: 5). The maximum rating of the fire pump engine will be 575 horsepower (hp). The emergency generator will have a maximum rated output of 2,000 kilowatts (kW). Both engines will be certified to applicable emissions standards with operation hours limited to 100 hours/year for each unit and operate solely in emergency situations and for required maintenance and testing.

6.3. FUEL GAS HEATER AND AUXILIARY BOILER

The Brownsville Generating Station will include one natural gas-fired fuel gas heater (FIN/EPN: 6) with a maximum rated heat input of 10 MMBtu/hr HHV. In addition to the fuel gas heater, the site will have an auxiliary boiler (FIN/EPN: 7). This boiler has a maximum rated heat input of 90 MMBtu/hr HHV. The fuel gas heater and the auxiliary boiler will be fired on pipeline-quality natural gas exclusively. The fuel gas heater is proposed to be authorized for 8,760 hours/year. Tenaska proposes to limit the usage of the auxiliary boiler by limiting its operation to 4,380 hours/year.

6.4. SF_6 CIRCUIT BREAKERS

The proposed project will include approximately 9 circuit breakers on site which contain sulfur hexafluoride (SF_6). There is expected to be minimal SF_6 leakage to the atmosphere (FIN/EPN: FUG_GHG).

6.5. PIPING COMPONENTS

The proposed project will include piping components in natural gas service. The Brownsville Generating Station will implement an Audio/Visual/Olfactory (AVO) program to reduce emissions from equipment leaks, with corresponding control efficiencies applied to the equipment leak fugitive calculations (FIN/EPN: FUG_GHG).

6.6. COOLING TOWER

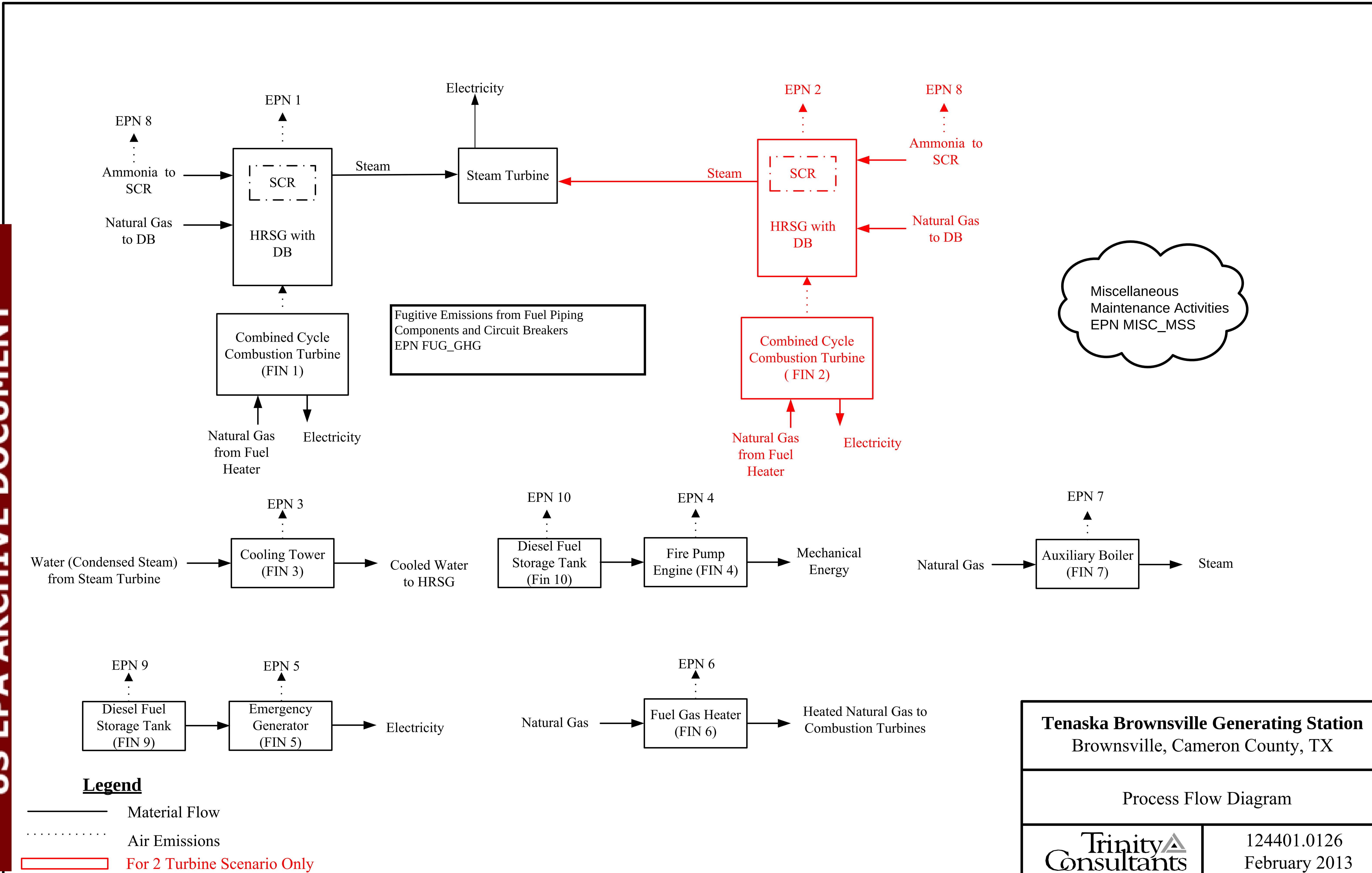
The Brownsville Generating Station will install one cooling tower (FIN/EPN: 3). Cooling tower emissions consist only of total suspended PM (TSP), PM_{10} and $PM_{2.5}$, originating from the dissolved solids (e.g., calcium, magnesium, etc.) in the circulating water that are assumed to crystallize and form airborne particulates as a portion of the circulating water escapes the cooling tower through the induced draft fans and evaporates. Particulate emissions from the cooling tower will be minimized by drift eliminators. The cooling tower is not a source of GHG emissions.

6.7. AMMONIA STORAGE AND UNLOADING SYSTEM

Anhydrous ammonia will be used in the SCR system. Anhydrous ammonia will be brought on-site via tank trucks and unloaded into a pressurized storage tank. The NH_3 unloading system will be equipped with a vapor return line to collect NH_3 vapors generated during unloading and will be routed back to the tank truck using a vacuum system. Ammonia will be transferred to the SCR system using transfer pumps and pipelines. Therefore, the ammonia storage tank and unloading operations are not considered as potential emission sources; however, fugitive emissions of NH_3 will be produced from equipment leaks from components in ammonia service (FIN/EPN: 8). The ammonia storage and unloading system are not a source of GHG emissions.

6.8. DIESEL STORAGE TANKS

Diesel used for the fire pump engine and the emergency generator will be stored in horizontal tanks that are internally associated with the engine enclosure (FIN/EPNs: 9 and 10 for emergency generator tank and fire pump engine tank, respectively). The diesel storage tanks are not a source of GHG emissions.


EPN 8
Ammonia to SCR
Natural Gas to DB
EPN 1
SCR
HRSG with DB
Steam
Electricity
Steam Turbine
Combined Cycle Combustion Turbine (FIN 1)
Natural Gas from Fuel Heater
Electricity
Fugitive Emissions from Fuel Piping Components and Circuit Breakers EPN FUG_GHG
EPN 2
EPN 8
Ammonia to SCR
Steam
SCR
HRSG with DB
Natural Gas to DB
Combined Cycle Combustion Turbine (FIN 2)
Natural Gas from Fuel Heater
Electricity
Miscellaneous Maintenance Activities EPN MISC_MSS
EPN 3
Water (Condensed Steam) from Steam Turbine
Cooling Tower (FIN 3)
Cooled Water to HRSG
EPN 10
Diesel Fuel Storage Tank (Fin 10)
EPN 4
Fire Pump Engine (FIN 4)
Mechanical Energy
EPN 7
Natural Gas
Auxiliary Boiler (FIN 7)
Steam
EPN 9
Diesel Fuel Storage Tank (FIN 9)
EPN 5
Emergency Generator (FIN 5)
Electricity
EPN 6
Natural Gas
Fuel Gas Heater (FIN 6)
Heated Natural Gas to Combustion Turbines
Legend
Material Flow
Air Emissions
For 2 Turbine Scenario Only
Tenaska Brownsville Generating Station
Brownsville, Cameron County, TX
Process Flow Diagram
Trinity Consultants
124401.0126
February 2013

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the emission sources of GHGs at the proposed Brownsville Generating Station. Detailed emission calculation spreadsheets, including example calculations, are included in Appendix B. These emission estimates reflect the emission limits and controls proposed as BACT in Section 10.

Potential GHG emissions from the proposed project will result from the following emission units:

- Combustion Turbines, Duct Burners and SUSD emissions (EPNs: 1 and 2);
- One Diesel Fire Pump Engine (EPN: 4);
- One Emergency Generator (EPN: 5);
- One Fuel Gas Heater (EPN: 6);
- One Auxiliary Boiler (EPN: 7);
- Fugitive Emissions from Fuel Piping Components and SF_6 Circuit Breaker Fugitive Emissions (EPN: FUG_GHG)

Table 7-1 provides a summary of the annual potential to emit emissions of GHGs for the proposed project.

Table 7-1. Proposed Project Potential GHG Emissions

Source	Annual Potential GHG Emissions (short tons per year)				
	CO_2	CH_4	N_2O	SF_6	CO_2e
Combustion Turbine 1/ Duct Burner (Normal Operations)	1,570,399.4	105.57	40.099	-	1,585,046
Combustion Turbine 2/ Duct Burner (Normal Operations	1,570,399.4	105.57	40.099	-	1,585,046
Fire Pump Engine	31.2	1.3E-03	2.52E-04	-	31
Emergency Generator	155.1	6.3E-03	1.26E-03	-	156
Fuel Gas Heater	5,119.7	0.10	0.010	-	5,125
Auxiliary Boiler	23,038.6	0.43	0.044	-	23,061
Fugitive SF_6 Circuit Breaker Emissions	-	-	-	0.005	122
Components Fugitive Leak Emissions	-	1.02	-	-	21
CCCT MSS Emissions		3,208.80	-	-	67,385
Total Project Emissions – 1 on 1 Scenario	**1,598,744.0**	**1,711.52**	**40.155**	**0.005**	**1,647,254**
Total Project Emissions – 2 on 1 Scenario	**3,169,143.4**	**3.421.49**	**80.254**	**0.005**	**3,265,993**

GHG emissions for the CCCTs (for both normal and MSS operations), were based on emission levels proposed as BACT and equipment specifications provided by the equipment manufacturer. For all other combustion sources, the GHG emissions for each emission unit were based on emission levels and controls proposed as BACT, proposed equipment specifications as provided by the manufacturer, and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel).

According to 40 CFR §52.21(b)(49)(ii), GHG emissions for PSD applicability must show CO_2e emissions calculated by multiplying the mass of each of the six GHGs by the gas' associated global warming potential (GWP), which is established in Table A-1 to Subpart A of 40 CFR Part 98. Table 7-2. Global Warming Potentials provides the GWP for each GHG emitted from this proposed project.

Table 7-2. Global Warming Potentials (GWPs)

Pollutant	GWP[1]
CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

[1] GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A.

The following is an example calculation for annual CO_2e emissions:

$$\begin{aligned} CO_2e \text{ Annual Emission Rate (tpy)} \\ = CO_2 \text{ Annual Emission Rate (tpy)} \times CO_2 \text{ GWP } + CH_4 \text{ Annual Emission Rate (tpy)} \times CH_4 \text{ GWP} \\ + N_2O \text{ Annual Emission Rate (tpy) } \times N_2O \text{ GWP} \\ + SF_6 \text{ Annual Emission Rate (tpy) } \times SF_6 \text{ GWP} \end{aligned}$$

7.1. COMBUSTION TURBINES

The combustion turbines at the proposed Brownsville Generating Station (EPNs: 1 and 2) will be either one or two of Mitsubishi's 501GAC combustion turbines. The CCCTs will be fired with pipeline-quality natural gas and have an estimated nominal summer condition power generation capacity of 400 MW or 800 MW, depending upon whether one or two CCCTs are constructed.

Each turbine is rated at a maximum nominal heat input capacity of 2,903 MMBtu/hr HHV at 20 °F ambient. The annual hours of operation for each CCCT will be to 8,760 hours per year (hr/yr). Each duct burner is rated a maximum heat input capacity of 250 MMBtu/hr HHV. The annual maximum hours of operation for each duct burner will be limited to 5,200 hr/yr.

GHG emissions are estimated based on emission levels proposed as BACT, proposed equipment specifications as provided by the manufacturer, and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (MRR). See Appendix A for detailed emission calculations.

GHG emissions from MSS activities result from the combustion of natural gas and the release of unburned natural gas, which contains methane. SUSD emissions from each combustion turbine are estimated based on a worst-case scenario of 2 hot starts, 350 warm starts, 2 cold starts, 2 cold cold starts, and 356 shutdown events per year. A planned startup of each CCCT is defined as the period that begins when the data acquisition and handling system (DAHS) measures fuel flow to the CT and ends when the CT generator (CTG) load reaches 50%. A planned shutdown of each CCCT is defined as the period that begins when the CTG output drops below 50% load and ends when there is no longer measurable fuel flow to the CCCT.

Further definitions for the four types of startup events as follows:

- A cold cold start is defined as a startup where the power block has not operated during the preceding 96 hours;
- A cold start is defined as a startup where the power block has not operated during the preceding 72 hours;
- A hot start is defined as a startup when the power block has operated within the previous 8 hours; and
- A warm start is a startup that is neither hot nor cold.

Annual CH_4 emissions during SUSD events are calculated based on CH_4 emissions from each SUSD event, duration of event SUSD event, and the number of SUSD events per year. Maximum CO_2 and N_2O emissions occur during steady state (i.e., non-SUSD) operations.

See detailed emission calculations in Appendix A.

7.2. FIRE PUMP ENGINE AND EMERGENCY GENERATOR

The Brownsville Generating Station will have two diesel-fired emergency engines: an emergency fire pump engine (FIN/EPN: 4) and an emergency generator (FIN/EPN: 5). The maximum rating of the fire pump engine will be 575 horsepower (hp). The emergency generator will have a maximum rated output of 2,000 kilowatts (kW). Both engines will be certified to applicable emissions standards and operate solely in emergency situations and for required maintenance and testing. The diesel fire pump engine and emergency generator will be limited to 100 hours per year for each unit for routine testing, maintenance, and inspection purposes only. Combustion of diesel fuel will result in emissions of CO_2, CH_4, and N_2O.

GHG emissions are estimated based on emission levels and controls proposed as BACT, proposed equipment specifications as provided by the manufacturer, and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (MRR). See Appendix A for detailed emission calculations.

7.3. FUEL GAS HEATER AND AUXILIARY BOILER

The Brownsville Generating Station will include one natural gas-fired fuel gas heater (FIN/EPN: 6) with a maximum rated heat input of 10 MMBtu/hr HHV. In addition to the fuel gas heater, the site will have an auxiliary boiler (FIN/EPN: 7). This boiler has a maximum rated heat input of 90 MMBtu/hr HHV. The auxiliary boiler will be fired on pipeline-quality natural gas exclusively. The fuel gas heater is proposed to be authorized for 8,760 hours/year. Tenaska proposes to limit the usage of the auxiliary boiler by limiting its operation to 4,380 hours/year.

GHG emissions for each emission unit were estimated based on emission levels and controls proposed as BACT, proposed equipment specifications as provided by the manufacturer, and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule (40 CFR 98, Subpart C, Tables C-1 and C-2 for natural gas and diesel).

7.4. CIRCUIT BREAKER SF_6 EMISSIONS

The proposed project will use approximately 9 circuit breakers on site which contain sulfur hexafluoride (SF_6). There is expected to be minimal SF_6 leakage to the atmosphere. SF_6 fugitive emissions (EPN: FUG_GHG) are calculated as follows:

Annual Emission Rate (short tpy) =
(Amount of SF_6 in Full Charge (lb)) x (SF_6 Leak Rate (%/yr)) x (1/2,000 (short ton/lb))

A worst-case leak rate of 0.5% per year was used from EPA's technical paper titled, "SF_6 Leak Rates from High Voltage Circuit Breakers - EPA Investigates Potential Greenhouse Gas Emission Source - by J. Blackman, Program Manager, EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting". See Appendix A for detailed emission calculations.

7.5. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

Fugitive emissions of CH_4 are produced by equipment leaks from components in natural gas service (EPN: FUG_GHG). The controlled CH_4 emissions are calculated using the methodology and emission factors obtained from Table 2 for Oil and Gas Production Operations from Addendum to RG-360, Emission Factors for Equipment Leak Fugitive Components, TCEQ, January 2008, gas factors. The Brownsville Generating Station will implement an Audio/Visual/Olfactory (AVO) program to reduce emissions from equipment leaks, with corresponding control efficiencies applied to the equipment leak fugitive calculations. See Appendix A for detailed emission calculations.

8. EMISSION POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2013	Permit No.:	TBD	Regulated Entity No.:	106579600
Area Name:	Tenaska Brownsville Generating Station			Customer Reference No.:	604252627

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) Pound Per Hour	(B) TPY
1	1	Combustion Turbine 1/Duct Burner	CH_4 (Normal Operations)	25.70	1,709.97
			CH_4 (MSS Operations)[1]	See Note 1	
			N_2O	9.46	40.10
			CO_2	370,435.00	1,570,399.40
			CO_2e (Normal operations)	373,907.00	1,618,738.40
			CO_2e (MSS operations)	See Note 1	
2	2	Combustion Turbine 2/Duct Burner	CH_4 (Normal Operations)	25.70	1,709.97
			CH_4 (MSS Operations)[1]	See Note 1	
			N_2O	9.46	40.10
			CO_2	370,435.00	1,570,399.40
			CO_2e (Normal operations)	373,907.00	1,618,738.40
			CO_2e (MSS operations)	See Note 1	
4	4	Fire Pump Engine	CH_4	0.03	<0.01
			N_2O	0.01	<0.01
			CO_2	623.24	31.20
			CO_2e	626.97	31.00
5	5	Emergency Generator	CH_4	0.13	0.01
			N_2O	0.03	<0.01
			CO_2	3,102.97	155.10
			CO_2e	3,115.00	156.00

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**February 2013**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**106579600**
Area Name:	**Tenaska Brownsville Generating Station**			**Customer Reference No.:**	**604252627**

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) Pound Per Hour**	**(B) TPY**
6	6	Fuel Gas Heater	CH_4	0.02	0.10
			N_2O	<0.01	0.01
			CO_2	1,168.88	5,119.70
			CO_2e	1,169.98	5,125.00
7	7	Auxiliary Boiler	CH_4	0.20	0.43
			N_2O	0.02	0.04
			CO_2	10,519.91	23,038.60
			CO_2e	10,530.31	23,061.00
FUG_GHG	FUG_GHG	Fugitive Emissions - GHGs	SF_6 (from circuit breakers)	<0.01	0.005
			CO_2e (from circuit breakers)	27.85	122.00
			CH_4 (from fuel piping components)	0.23	1.02
			CO_2e (from fuel piping components)	4.79	21.00

EPN = Emission Point Number
FIN = Facility Identification Number

[1] **Unburned CH_4 emisions during MSS operations are provided for the annual emission limits.**

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2013	Permit No.:	TBD	Regulated Entity No.:	106579600
Area Name:	Tenaska Brownsville Generating Station			Customer Reference No.:	604252627

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above Ground	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	(Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
1	1	Combustion Turbine 1/Duct Burner	14	649,867	2,879,440		160	18	55.98	177			
2	2	Combustion Turbine 2/Duct Burner	14	649,915	2,879,440		160	18	55.98	177			
4	4	Fire Pump Engine	14	649,859	2,879,373	10.0	10	0.5	282.49	906			
5	5	Emergency Generator	14	649,821	2,879,437	12.0	12	1.5	95.23	762			
6	6	Fuel Gas Heater	14	649,992	2,879,495		30	2.5	17.06	1000			
7	7	Auxiliary Boiler	14	649,802	2,879,447		40	4	42.78	331			
FUG_GHG	FUG_GHG	Fugitive Emissions - GHGs	14	650,310	2,879,452					Ambient	39	43	

EPN = Emission Point Number
FIN = Facility Identification Number

9. FEDERAL REGULATORY REQUIREMENTS

This section addresses the applicability of the following parts of 40 CFR for the equipment at the proposed Brownsville Generating Station:

- Prevention of Significant Deterioration (PSD) in 40 CFR Section 52.21;
- New Source Performance Standards (NSPS) in 40 CFR Part 60;
- National Emissions Standards for Hazardous Air Pollutants (NESHAP) in 40 CFR Part 61; and
- NESHAP in 40 CFR Part 63, i.e., Maximum Available Control Technology (MACT) rules.

9.1. PSD APPLICABILITY REVIEW

A stationary source is considered "major" for PSD if it has the potential to emit either (1) 100 tpy or more of a regulated pollutant if the source is classified as one of 28 PSD major facility source categories, or (2) 250 tpy or more of any regulated pollutant for unlisted sources. Fossil fuel-fired steam electric plants with heat input greater than 250 MMBtu/hr are one of the 28 PSD major facility categories. Sources on this list are also required to include fugitive emissions in determining whether the source is a "major stationary source" and therefore subject to the PSD permitting program.

The proposed Brownsville Generating Station is within a major facility category and is subject to a 100 tpy threshold for classification as a PSD major source. The Brownsville Generating Station is estimated to have potential emissions in excess of 100 tpy for NO_x, CO, VOC and GHG and will therefore be considered a new major source with respect to the PSD program. According to EPA guidance, "major for one, major for all" PSD policy, if a site is major for one or more criteria pollutants, then the other criteria pollutant emissions need to be compared to the Significant Emission Rates (SERs) when determining PSD applicability for particulate matter (PM), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist. Based on emissions estimates for the Brownsville Generating Station, the proposed project will be PSD major for NO_X, CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4 mist, and GHGs.

The proposed potential source-wide emissions of all federally regulated NSR pollutants are compared to the applicable PSD SERs in Table 9.1-1.

Table 9.1-1. Proposed Potential Emissions Compared with PSD Thresholds and PSD SERs

PSD Applicability Summary (1 on 1 Scenario)

	CO	NO_x	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	H_2SO_4 Mist	CO_2e
Site-wide Emissions (tpy)	828	155	59	40	36	9	262	7	1,647,254
PSD Major Source Threshold (tpy)	100	100	100	100	100	100	100	100	100,000
Is the site above PSD limits?	**YES**	**YES**	NO	NO	NO	NO	**YES**	NO	**YES**
Significant Emission Rates (SER) (tpy)	100	40	25	15	10	40	40	7	75,000
Is the site above SER?	**YES**	**YES**	**YES**	**YES**	**YES**	NO	**YES**	**NO**	**YES**

PSD Applicability Summary (2 on 1 Scenario)

	CO	NO_x	PM	PM_{10}	$PM_{2.5}$	SO_2	VOC	H_2SO_4 Mist	CO_2e
Site-wide Emissions (tpy)	1,644	304	92	74	70	18	525	14	3,265,993
PSD Major Source Threshold (tpy)	100	100	100	100	100	100	100	100	100,000
Is the site above PSD limits?	**YES**	**YES**	NO	NO	NO	NO	**YES**	NO	**YES**
Significant Emission Rates (SER) (tpy)	100	40	25	15	10	40	40	7	75,000
Is the site above SER?	**YES**	**YES**	**YES**	**YES**	**YES**	NO	**YES**	**YES**	**YES**

The estimated GHG emissions from the proposed Brownsville Generating Station are greater than 100,000 tpy on a CO_2e basis and will trigger the requirement for PSD permitting due to being a major source of GHG emissions. The proposed project will also result in a significant net emissions increase for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and H_2SO_4 Mist emissions. Therefore, PSD requirements, including best available control technology (BACT), apply for GHGs and for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, VOC, and H_2SO_4 Mist emissions. Tenaska Brownsville Generating Station is submitting two separate applications; one to the TCEQ for authorization of its non-GHG emissions in accordance with the PSD rules and this one to the EPA for authorization of its GHG emissions. The application to authorize the non-GHG emissions is being submitted to the TCEQ .

Under the PSD regulations, each new source or modified emission unit subject to PSD is required to undergo a BACT review. The BACT requirements for GHG emissions from the Brownsville Generating Station are addressed in Section 10 of this application.

9.2. NEW SOURCE PERFORMANCE STANDARDS

EPA proposed a new New Source Performance Standard (NSPS) that, as proposed, will be applicable to the GHG emissions from the proposed CCCTs at the Brownsville Generating Station. The final requirements of this NSPS are not known at this time. However, since this project will commence construction after the proposal date of NSPS TTTT, the affected source will be subject to the final limits established by NSPS Subpart TTTT, as adopted.

Applicability: As proposed, NSPS Subpart TTTT applies to electric utility generating units (EGUs) that commence construction after April 13, 2012 with a base load rating of more than 250 MMBtu/hr heat input of fossil fuel, unless the unit qualifies for certain exceptions that are not applicable here. Key definitions for applicability are as follows.

> Electric utility generating unit *or* EGU *means any steam electric generating unit or stationary combustion turbine that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale….*
>
> Stationary combustion turbine *means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post combustion emission control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system….*
>
> *Steam electric generating unit means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines*

Brownsville Generating Station will have one or two combustion turbines, each with a heat input exceeding 250 MMBtu/hr and each supplying more than 25 MW to the power grid. The CCCT will include both a stationary combustion turbine and a steam electric generating unit. As such, the Brownsville CCCTs are subject to NSPS Subpart TTTT as proposed.

Emission Limits: NSPS Subpart TTTT, as proposed, includes a 1,000 $lb/MW\text{-}hr_{gross}$ CO_2 emission limit on a 12-operating month annual average basis. Emissions from each CCCT will be limited to 914 lb of $CO_2/MW\text{-}hr_{gross}$ at ISO conditions (Standard pressure at 14.696 psia and temperature at 60 degree F), at base load and at plant elevation.

The proposed emission limit includes emissions from the duct burner for each CCCT. The compliance with the proposed emission limits will be demonstrated on 12- operating month annual average basis. This value includes a degradation factor of 12.3% to account for normal wear and tear of the equipment. The details of these degradation factors are included in Section 10.5.6. Therefore, it is expected the proposed CCCTs will comply with NSPS Subpart TTTT, as proposed.

9.3. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

There are currently no NESHAPs or MACTs for the regulation of GHGs. The applicable criteria pollutant MACTs are addressed in the Criteria Pollutant PSD application submitted to the TCEQ under a separate cover.

This section documents the assumptions, methodologies and conclusions of the BACT analysis undertaken to determine the BACT based limits on GHG emissions from the proposed emission units.

10.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulation at 40 CFR § 52.21(j)(2):

(j) Control Technology Review. ...

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations at 40 CFR § 52.21(b)(12)(emphasis added) as follows:

...an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61.

Differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

10.1.1. Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is predicated upon the application of technologies reflecting the maximum reduction rate achievable, the final result of a BACT determination is an emission limit. Typically, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu HHV, ppm, or lb/hr). [2, 3] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes.[4]

[2] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[3] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per unit of heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per unit of time).

[4] US EPA,, *PSD and Title V Permitting Guidance for Greenhouse Gases.* EPA-457/B-11-001 (Mar. 2011), page 46 (hereinafter "2011 Guidance")

10.1.2. Each Pollutant

Because BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[5] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six GHGs and not a single pollutant. In the final Tailoring Rule preamble, EPA made clear that this combined pollutant approach for GHGs did not apply just to PSD applicability determinations but also to PSD BACT determinations, such that applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG pollutant:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[6]

Tenaska acknowledges the potential benefits of conducting a single GHG BACT evaluation on a CO_2e basis for the purposes of addressing potential tradeoffs among constituent gases for certain types of emission units. However, for the proposed Brownsville Generating Station, the GHG emissions are predominated by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

10.1.3. BACT Applies to the Proposed Source

The applicant defines the proposed source (i.e., its goals, aims, and objectives). BACT applies to the type of source proposed by the applicant. Accordingly, EPA's GHG Permitting Guidance states that applicants need not identify control options that fundamentally redefine the source or the applicant's purpose.[7]

10.1.4. Case-by-Case Basis

The PSD program's BACT evaluation is case-by-case. In 1990, EPA issued a Draft Manual on New Source Review permitting, which included a "top-down" BACT analysis, to assist applicants and regulators with this case-by-case process.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify*

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[5] 40 CFR §52.21(b)(12)

[6] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule*, June 3, 2010.

[7] "EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility." 2011 Guidance, page 26

a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.[8]

The five steps in a top-down BACT evaluation can be summarized as follows:

Step 1. Identify all available control technologies;
Step 2. Eliminate technically infeasible options;
Step 3. Rank the technically feasible control technologies by control effectiveness;
Step 4. Evaluate most effective controls; and
Step 5. Select BACT.

While this EPA-recommended five step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[9]

10.1.5. Achievable

BACT is to be set at the lowest value that is "achievable." However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the D.C. Circuit Court of Appeals:

Where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."[10]

EPA has reached similar conclusions in prior determinations for PSD permits.

Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured "emissions rates," which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.[11]

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[8] Draft NSR Manual at B-2. "The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training, and as a guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to by this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr.*, 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

[9] Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

[10] *Sierra Club v. U.S. EPA*, 167 F.3d 658 (D.C. Cir. 1999), quoting. *National Lime Ass'n v. EPA,* 627 F.2d 416, 431 n.46 (D.C. Cir. 1980).

[11] EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

Thus, BACT must be set recognizing that compliance with that limit must be achievable for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

10.1.6. Production Process

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

10.1.7. Available

The term "available" in the definition of BACT is implemented through a feasibility analysis – a determination that the technology being evaluated is demonstrated or available and applicable.

10.1.8. Floor

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61). As discussed in Section 9.2, NSPS Subpart TTTT, as proposed, includes a 1,000 $lb/MW\text{-}hr_{gross}$ CO_2 emission limit on a 12- operating month annual average basis. Therefore, this applicable limit, as proposed, is considered the floor for BACT analysis.

10.2. GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed project has been evaluated via a "top-down" approach, which includes the steps outlined in the following subsections.

It should be noted that EPA clarified the scope of a GHG BACT review in two ways:

> EPA stressed that applicants should clearly define the scope of the project being reviewed. Tenaska has provided this information in Section 6 (Process Description) of this application.[12]
> EPA clarified that the BACT analysis should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review. Because the project's GHG emissions are predominated by the two natural gas CCCTs, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project.

10.2.1. Step 0 - Define the Project

Historical practice, as well as recent court rulings, has been clear that a key foundation of the BACT process is that BACT applies to the type of source proposed by the applicant, and that redefining the source is not appropriate in a BACT determination.

[12] *2011 Guidance*, pages 22-23.

Though BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. As EPA notes, a key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. As discussed by EPA in an opinion on the Prairie State PSD project,

> *We find it significant that all parties here, including Petitioners, agree that Congress intended the permit applicant to have the prerogative to define certain aspects of the proposed facility that may not be redesigned through application of BACT and that other aspects must remain open to redesign through application of BACT.*[13]
>
> …
>
> *When the Administrator first developed* [EPA's policy against redefining the source] *in Pennsauken, the Administrator concluded that permit conditions defining the emissions control systems "are imposed on the source as the applicant has defined it" and that "the source itself is not a condition of the permit.*[14]

Given that some parts of the project are not open for review under BACT, EPA then discusses that it is the permit reviewer's burden to define the boundary. Based on precedent set in multiple prior EPA rulings (e.g., Pennsauken County Resource Recovery [1988], Old Dominion Electric Coop [1992], Spokane Regional Waste to Energy [1989]), EPA states the following in the Prairie State PSD Appeal:

> *For these reasons, we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.* [15]

EPA's opinion in Prairie State was upheld on appeal to the Seventh Circuit Court of Appeals, where the court affirmed the substantial deference due the permitting authority on defining the demarcation point.[16] Taken as a whole, the permitting agency is tasked with determining which controls are appropriate, but the discretion of the agency does not extend to a point requiring the applicant to redefine the source. As such, it is imperative for Tenaska to include a discussion under "Step 0" of the GHG BACT Assessment Methodology as to what actually constitutes the proposed project and its fundamental objectives and basic design. Please refer Section 6 (Process Description) for what constitute the scope of the proposed project.

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[13] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 26.

[14] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 29.

[15] EPA Environmental Appeals Board decision, *In re: Prairie State Generating Company*. PSD Appeal No. 05-05, decided August 24, 2006, Page 30. See also EPA Environmental Appeals Board decision, *In re: Desert Rock Energy Company LLC*. PSD Appeal Nos. 08-03, 08-04, 08-05 & 08-06, decided Sept. 24, 2009, page 64 ("The Board articulated the proper test to be used to [assess whether a technology redefines the source] in *Prairie State*.").

[16] *Sierra Club v. EPA and Prairie State Generating Company LLC*, Seventh Circuit Court of Appeals, No. 06-3907, August 24, 2007. Rehearing denied October 11, 2007.

10.2.2. Step 1 - Identify All Available Control Technologies

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified under Step 1. The application of demonstrated control technologies in other source categories similar to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
2. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies, including EPA Region 6 website with the details of PSD GHG permit applications;[17]
3. Engineering experience with similar control applications;
4. Information such as commercial guarantees provided by air pollution control equipment vendors with significant market share in the industry; and/or
5. Review of peer reviewed literature from industrial technical or trade organizations.

10.2.3. Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is deemed feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45.[18] "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[19]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[20] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is 'applicable' if it can reasonably be installed and operated on the source type under

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[17] GHG PSD permits and applications available at EPA Region 6 website, http://yosemite.epa.gov/r6/Apermit.nsf/AirP, accessed January 2013.

[18] PSD Appeal No. 05-05, Prairie State Generating Company (decided August 24, 2006), page 13.

[19] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[20] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

consideration."[21] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

10.2.4. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

10.2.5. Step 4 - Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the Global Warming Potential (GWP) of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_X emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_X emissions above the reduction of CO emissions, approving low NO_X control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

10.2.6. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

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[21] Ibid.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Work Group has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, National Ambient Air Quality Standards (NAAQS) are not established for GHGs and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Tenaska proposes only an annual average GHG BACT limit.

10.3. GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit for which the calculated GHG emissions are subject to PSD review. The proposed Brownsville Generating Station is a new major source with respect to GHG emissions. The estimated GHG emissions from the proposed facility will be greater than 100,000 tpy on a CO_2e basis primarily due to the combustion of natural gas in the two turbines.

Potential emissions of GHGs from the proposed Brownsville Generating Station will result from the following emission units:

- Combustion turbines, duct burners, and SUSD emissions (EPN: 1 and 2);
- Fire Pump Engine (EPN: 4);
- Emergency Generator (EPN: 5);
- Fuel Gas Heater (EPN: 6);
- Auxiliary Boiler (EPN: 7);
- Fugitive emissions from fuel piping components (EPN: FUG_GHG); and
- Fugitive emissions from SF_6 circuit breakers (EPN: FUG_GHG).

This BACT analysis focuses mainly on the predominant sources of CO_2e from the project (i.e., combustion turbines). GHG emissions from small emission sources such as the fire pump engine, emergency generator, fuel gas heater, auxiliary boiler, MSS activities, circuit breaker equipment leaks, and fuel piping component leaks are included in the BACT analysis as well.

The emission calculations provided in Appendix A include a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Brownsville Generating Station. GHG emissions for each emission unit are estimated based on emission limits and controls proposed as BACT, proposed equipment specifications provided by the manufacturer, and the default emission factors in the EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR 98, Subpart C).

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

1. PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[22]

[22] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

2. Report of the Interagency Task Force on Carbon Capture & Storage (hereafter referred to as CCS Task Force Report)[23]

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Brownsville Generating Station following the EPA's five-step "top-down" BACT process. Tenaska is proposing the use of good combustion, operating and maintenance practices together with other BACT controls described below for all the stationary combustion sources at the proposed facility.

Table 10.1 provides a summary of the proposed BACT limits discussed in the following sections.

Table 10.1. Proposed GHG BACT Limits for the Brownsville Generating Station

EPN	Description	Proposed BACT Limit[a] (CO_2e tpy)	Proposed BACT Limit[b] (lbs of CO_2/MW-hr_{gross})
1	Combustion Turbine 1/ Duct Burner (Normal Operations)	1,585,046	914
2	Combustion Turbine 2/ Duct Burner (Normal Operations)	1,585,046	914
4	Fire Pump Engine	Work Practice Standards	
5	Emergency Generator	Work Practice Standards	
6	Fuel Gas Heater	5,125	
7	Auxiliary Boiler	23,061	
1 and 2	MSS Operations for CCCTs	Work Practice Standards	
FUG_GHG	Fugitive emissions from equipment leaks	Work Practice Standards	

[a] The BACT limits are represented in short tons

[b] The BACT limits are represented at ISO conditions (Standard pressure at 14.696 psia and temperature at 60 degree F), at base load, and at plant elevation.

A detailed BACT analysis is conducted for the two combustion turbines, MSS emissions from the combustion turbines, the fire water pump, emergency generator, fuel gas heater, auxiliary boiler, fugitive emissions from fuel piping components, and the circuit breaker equipment leaks.

10.5. COMBUSTION TURBINES

GHG emissions from the proposed combustion turbines consist of CO_2, CH_4, and N_2O and result from the combustion of natural gas. The following section presents a GHG BACT evaluation for the proposed CCCTs.

[23] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf

10.5.1. Step 0 – Define the Project

As described in Section 1.1 of this report, Tenaska's fundamental objective in pursuing the proposed project is to construct a pipeline quality natural gas-fired CCCT facility near Brownsville for the reliable and economical supply of an estimated nominal power generation summer condition capacity of 400 MW or 800 MW on a flexible or baseload basis.

10.5.2. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for CCCTs that are analyzed as part of this BACT analysis consists of:

- Carbon Capture and Sequestration,
- Evaporative Cooling,
- Selection of Efficient CCCT,
- Fuel Selection, and
- Good Combustion, Operating, and Maintenance Practices.

10.5.2.1. Carbon Capture and Sequestration

CCS involves "capturing" and separating the CO_2 from the exhaust of the emission source, transporting the CO_2 to an appropriate injection site, and then storing CO_2 at a suitable sequestration site. The following sections describe the technical feasibility of each of the three steps necessary for the successful implementation of CCS. The CO_2 transfer options include both transfer to a pipeline or use in Enhanced Oil Recovery (EOR).

10.5.2.1.1. *CO_2 Capture*

CCS would involve post combustion capture of the CO_2 from the combustion turbines and duct burners and sequestration of the CO_2 in some fashion. In theory, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale, and solid sorbents and membranes are only in the research and development phase.

Florida Power & Light (FP&L) conducted CO_2 capture to produce 320-350 tpd CO_2 using the Fluor Econamine FG℠ scrubber system on 15 percent of the flue gas from its 320 MWe 2 x 1 natural gas combined cycle unit in Bellingham, Massachusetts from 1991 to 2005. The captured CO_2 was compressed and stored on site for sale to two nearby major food processing plants.[24, 25] Therefore, this project indicates CO_2 capture is potentially technically feasible for a small slip stream of natural gas combined cycle (NGCC) flue gas.

As discussed below, a number of larger scale coal-based CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI).[26]

> *"CCPI is pursuing three pre-combustion and three post-combustion CO_2 capture demonstration projects using currently available technologies (see Appendix A, Table A-8) . . . The post-combustion projects will capture CO_2 from a portion of the PC plant's flue gas stream. The specific projects include the following:*

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[24] International Energy Agency GHG Research & Development Program, *RD&D Database: Florida Light and Power Bellingham CO_2 Capture Commercial Project*, http://www.ieaghg.org/index.php?/RDD-Database.html.
[25] Reddy, Satish, et. al., Fluor's Econamine FG Plus℠ Technology for CO_2 Capture at Coal-fired Power Plants, Power Plant Air Pollutant Control "Mega" Symposium, August 25-28, 2008, Baltimore, Maryland, http://web.mit.edu/mitei/docs/reports/reddy-johnson-gilmartin.pdf.
[26] CCS Task Force Report, August 2010, p. 32.

- *Basin Electric: amine-based capture of 900,000 tonnes per year of CO_2 from a 120 MW equivalent slipstream at a North Dakota plant for use in an EOR application and/or saline storage.*
- *NRG Energy: amine-based capture of 400,000 tonnes per year of CO_2 from a 60 MW equivalent slipstream at a Texas plant for use in an EOR application.*
- *American Electric Power: ammonia-based capture of 1.5 million tonnes per year of CO_2 from a 235 MW equivalent slipstream at a West Virginia plant for saline storage."*

None of these CCS projects are operating and, in fact, none have been fully designed or constructed. Furthermore, American Electric Power recently announced that the CCS project has been put on hold due to the lack of federal carbon limits. [27] Finally, Tenaska is currently in the process of developing a 900 MWe_{gross} generating plant fueled by pulverized coal near Sweetwater, Texas. Tenaska is planning to capture 85 to 90 percent of the CO_2 emitted from the plant using the Fluor Econamine FG Plus[sm] (amine-based) technology, and send the captured CO_2 to the Permian Basin for enhanced oil recovery.[28] This plant has also not yet begun construction.

As mentioned above, there has been only one case of post combustion capture of CO_2 from a natural gas CCCT facility and it utilized only a small slip stream of the total exhaust gas volume. One reason for there being more, yet still not full-scale commercial, experience on coal-based combustion flue gas is that the exhaust from a coal-fueled plant has a significantly higher concentration of CO_2 as compared to a more dilute stream from the combustion of natural gas (approximately 13-15 $\text{percent}_{\text{volume}}$ for a coal fired system versus 3-5 $\text{percent}_{\text{volume}}$ for a natural-gas fired system).[29] Based on the emissions and stack exhaust data provided by the CCCT manufacturer, the concentration of CO_2 varies from 4 to 5 percent for the proposed CCCTs.

In addition, prior to sending the CO_2 stream to the appropriate sequestration site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[30]

While carbon capture technology may be technologically available on a small-scale, it has not been demonstrated in practice for full-scale natural gas combined cycle power plants, such as the proposed Brownsville Generating Station.

10.5.2.1.2. CO_2 Transport

CO_2 capture has not been demonstrated in practice on a full sized natural gas power plant and, therefore, not commercially available as BACT. Nonetheless, Tenaska is including a discussion on the feasibility of transporting the CO_2 captured from the exhaust of the CCCTs to an appropriate sequestration site. Tenaska would need to either transport the captured CO_2 to an existing CO_2 pipeline located at the Hastings Oil Field, operated by Denbury Resources (258 miles from the proposed Brownsville Generating Station[31]), or transport the CO_2 to a site with recognized potential for storage (e.g., enhanced oil recovery [EOR] sites). The closest potential EOR site is an existing oil well, located in Jim Hogg County, operated by Wynn - Crosby Operating, Ltd. (Jim Hogg Well, API No. 24732057). This well is located approximately 106 miles from the proposed Brownsville Generating Station. [32] Refer to Figures

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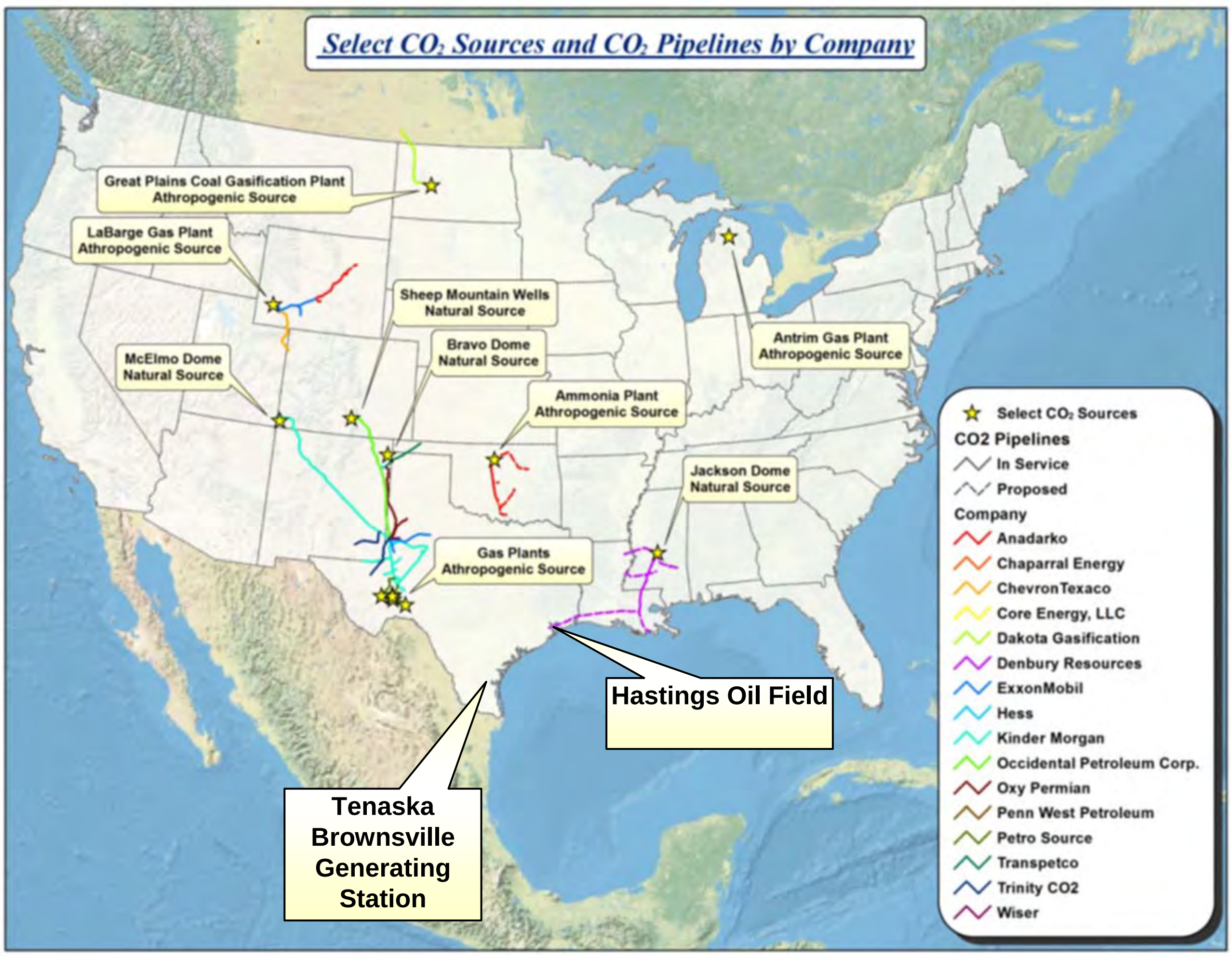
[27] Sweet, Cassandra. *The Wall Street Journal.* "AEP Drops Carbon Storage Project On Lack Of Federal Carbon Limits". http://online.wsj.com/article/BT-CO-20110714-716173.html. July 14, 2011.
[28] Tenaska, July 26, 2010, http://www.tenaska.com/newsItem.aspx?id=82
[29] CCS Task Force Report, August 2010, p. 29 and CO_2 concentrations from vendor provided exhaust characteristics
[30] CCS Task Force Report, August 2010, p. 30.

[31] CCS Task Force Report, August 2010, p, 159 – Appendix B.1 – Existing Pipeline Networks in the United States

[32] RRC Online System – Oil & Gas Data Query

10.1 and 1.2 below for maps illustrating the distance from the proposed facility to the closest CO_2 pipeline located at the Hastings Oil Field and the Jim Hogg Well site respectively.

Figure 10.1. CO_2 Sources and Pipelines[33]



[33] This map is taken directly from CCS Task Force Report, p. B-1.

Figure 10.2. Jim Hogg Well in Relation to the Brownsville Generating Station

It is technically feasible to construct a CO_2 pipeline 106 miles to the closest potential sequestration site.

10.5.2.1.3. CO_2 Storage

The process of injecting CO_2 into subsurface formations for long-term sequestration is referred to as CO_2 storage. CO_2 can be stored underground in oil/gas fields, un-mineable coal seams, and saline formations. In practice, CO_2 is currently injected into the ground for enhanced oil and gas recovery. Per the CCS Task Force Report, approximately 50 million tonnes of CO_2 per year are injected during enhanced oil and gas recovery operations.

Internationally, there are three large scale projects that are currently in operation worldwide as follows:[34]

1. The Sleipner Project (1996 – current): One million tonnes of CO_2 per year is separated from produced natural gas in Norway and is injected into Utsira Sand (high permeability, high porosity sandstone) 1,100 meters below the sea surface.
2. The Weyburn Project (2000 – 2011): 1.8 million tonnes of CO_2 per year was injected into 29 horizontal and vertical wells into two adjacent carbonate layers in Saskatchewan, Canada near the North Dakota border. The CO_2 originates from a nearby synfuel plant.[35]
3. The Snohvit Project (2010 – current): The project is expected to inject 0.7 million tonnes CO_2 per year from natural gas production operations near the Barents Sea. The injection well reaches 2,600 meters beneath the seabed in the Tubasen sandstone formation.
4. The In Salah Project (2004 – current): The project injects 1.2 million tonnes of CO_2 annually produced from natural gas into 1,800 meter deep muddy sandstone (low porosity, low permeability).

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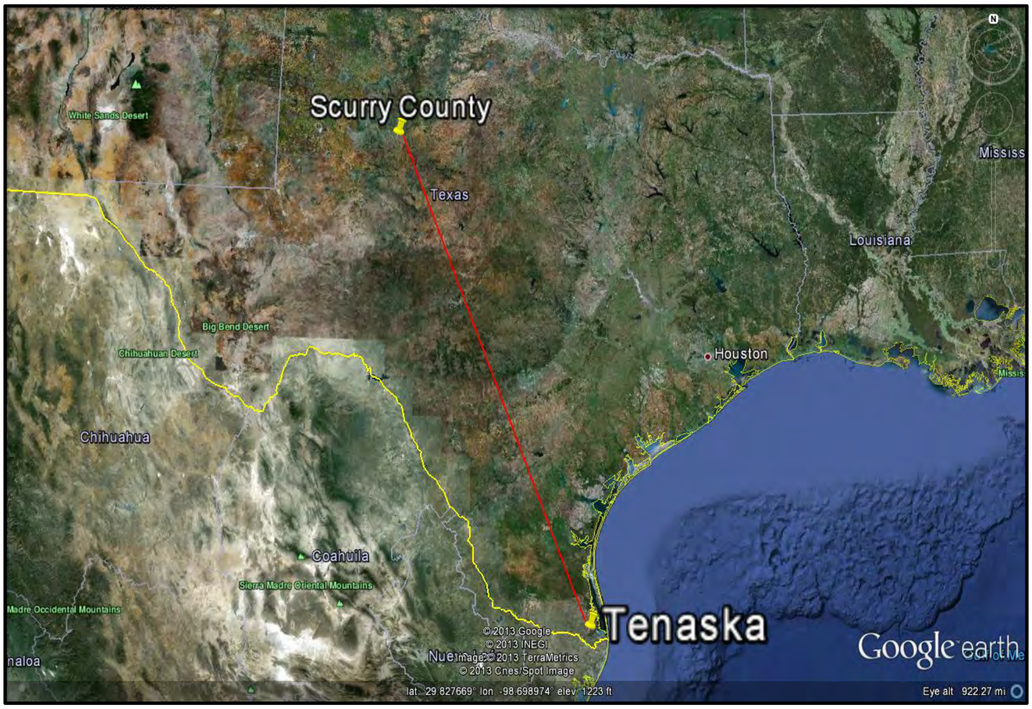
[34] CCS Task Force Report, Pages C-1 and C-2.

[35] Petroleum Technology Research Centre, http://www.ptrc.ca/weyburn_overview.php

In Texas, EOR is currently conducted on a large scale at the Scurry Area Canyon Reed Operators (SACROC) oilfield near the eastern edge of the Permian Basis in Scurry County, Texas. Since 1974, over 175 million tonnes of CO_2 have been injected into the SACROC oilfield for EOR.[36] The SACROC oilfield is approximately 505 miles from the Brownsville Generating Station. Figure 10.3 below provides a visual illustration of the proximity of the Brownsville Generating Station to the SACROC oilfield. EOR is occurring in other areas of Texas as well, and for purposes of this analysis, Tenaska has identified the closest potential sequestration site as the Jim Hogg Well (API No. 24732057) located in Jim Hogg County, which is approximately 106 miles from the proposed Brownsville Generating Station.

Figure 10.3: SACROC Oil Field in Relation to the Brownsville Generating Station[37]



In conclusion, even though transporting and sequestering CO_2 is feasible, CCS is not a viable, technically feasible option for this project due to the fact that CO_2 capture has not been achieved in practice for a large scale, 800 MW natural gas combined cycle plant, which was determined by Tenaska not to be feasible in Section 10.5.2.1.1. Nevertheless, Tenaska has chosen to carry it forward in the BACT analysis to evaluate and present the associated environmental, energy and economic impacts.

10.5.2.2. Evaporative Cooling

Evaporative cooling involves the cooling of gas turbine inlet air in order to increase combustion air mass flow. Air flows through a wetted medium and is cooled as some of the water evaporates off the wet media and into the inlet air. The evaporation process reduces the air temperature. Cooled air then passes through a mist eliminator to remove

[36] Bureau of Economic Geology, SACROC Research Project, http://www.beg.utexas.edu/gccc/sacroc.php

[37] Map obtained from the following website: http://www.beg.utexas.edu/gccc/sacroc.php

leftover water droplets, and is then directed into the compressor inlet. Cooling the combustion air increases the density and, therefore, results in a higher mass-flow rate and pressure ratio, resulting in increased turbine output and efficiency. The two CCCTs will employ evaporative cooling when ambient temperatures are high enough to render it effective.

10.5.2.3. Selection of Efficient CCCT

Tenaska conducted a comprehensive evaluation of the available CCCTs that could be installed at the proposed Brownsville Generating Station while remaining consistent with the project definition. Several advanced heavy duty frame type combustion turbine technologies were considered and evaluated such as General Electric's 7FA.05, Siemens SGT6-5000F5ee, Siemens SGT6-8000H, Mitsubishi 501GAC, Mitsubishi 501J. Evaluation criteria included plant size, market considerations, heat rate, operating experience, capital and O&M costs, and all-in levelized cost of energy. Each of the aforementioned combustion turbine models were evaluated solely in a combined cycle configuration.

Table 10.2 below includes a comparison of the CCCTs evaluated based on the efficiency of the turbines (e.g., Btu input per kWh output) and net plant output in 2x1 configuration. In general, GHG emissions are proportional to heat rate.

Table 10.2. CCCTs Evaluated

CCCT Description	Combined Cycle Unfired Net Plant Heat Rate (Btu/kW-hr) LHV[38]	Net Plant Output 2x1 Configuration
MHI 501GAC	5,744	810.7
Siemens SGT6-5000F	5,970	620.0
GE 7FA.05	5,831	647.8
Siemens SGT6-8000H	5,691	822.0
MHI 501J	5,531	942.9

As shown in Table 10.2, the GE 7FA.05 and Siemens SGT6-5000F have significantly lower output rates than the desired nominal plant output and have higher heat rates compared to the other models. The MHI 501J model exceeds the desired nominal 400 MW or 800 MW plant output. Although Table 10.2 indicates the Mitsubishi 501J and Siemens SGT6-8000H exhibit a slightly better net plant design heat rate (approximately 1%), either a single unit or two-unit combined cycle configuration utilizing those turbines exceeds the desired nominal 400 MW or 800 MW plant output. Based on the evaluation criteria above, the Mitsubishi 501GAC was selected as best meeting Tenaska's project scope, since the output for this model is the closest to the desired plant output for normal operations.

In addition, Tenaska proposes to use duct burners to provide additional power during peak demand periods. A detailed project analysis including alternative options considered for the duct burners is provided in Appendix B. As

[38] Gas Turbine World 2012 Performance Specs 28th Ed.; ISO Conditions

shown in this analysis, use of duct burners is the only economically reasonable option to meet Tenaska's project scope.

In order for the Brownsville Generating Station to provide flexible, baseload capacity to "balance" other intermittent generation such as wind it must have the ability to start and stop as dictated by dispatch. Therefore, a conservative approach has been taken with respect to the estimated annual number of startups and shutdowns, by assuming the units will cycle daily (one warm start and stop each day) in addition to two hot starts each year, and two annual cold and cold cold starts following preventative maintenance outages. While the number of each type of start is not proposed as a permit limit, nor would that be appropriate, the emissions calculated according to this schedule will be included in the annual permit limits. The assumptions used present a worst-case annual scenario taking into account the number of hours of CT downtime associated, by definition, with each type of start as follows:

- Hot <8 hrs
- Warm >8 hrs but <72 hrs
- Cold >72 hrs but < 96 hrs
- Cold Cold > 96 hrs

For example, although the cold and cold cold starts have higher emissions due to their longer duration, this is less conservative on an annual basis because the turbines are assumed to be down for the preceding 72-96 hours and, therefore, have no normal operating emissions during that time.

The duration of such events, particularly startups, is dictated by several factors including ambient temperature, elapsed time since last operation, equipment temperature, equipment warranty restrictions, off-taker contractual obligations, and dispatch instructions. Of course the Brownsville Generating Station has every incentive to minimize the durations, as these are less efficient modes of operation while little to no power is being sold. Plant operations will be optimized to minimize the frequency and duration of starts and stops to the extent practical.

Faster combustion turbine start capabilities are available in the market and have been considered for the Mitsubishi 501GAC and other combustion turbine models. The fast start options have a detrimental impact on overall plant performance and maintenance costs. The Brownsville Generating Station will primarily be a base loaded, combined cycle plant, as market allows. For this reason, as well as performance and maintenance considerations, the higher-performing standard Mitsubishi 501GAC was selected.

The plant will be designed to optimize (i.e., minimize) plant startup durations. The proposed auxiliary boiler will be used to facilitate commissioning and pre-commercial operation plant startup activities, as well as post-commercial operation plant startups and maintenance activities. The auxiliary boiler can be used to warm steam piping and balance of plant systems in addition to providing steam for steam turbine seals to aid in reducing startup durations and related emissions.

10.5.2.4. Fuel Selection

Tenaska proposes the use of pipeline quality natural gas as the sole fuel source for the two CCCTs being proposed as part of this project. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (in terms of kg/MMBtu) for a wide variety of industrial fuel types. As shown in this table, Natural gas has the lowest carbon intensity of any available fuel for the combustion turbines. The proposed combustion turbines will be fired with only pipeline quality natural gas fuel.

10.5.2.5. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices (GCPs) are a potential control option by improving the fuel efficiency of the combustion turbines. GCPs also include proper maintenance and tune-up of the combustion turbines at least annually per the manufacturer's specifications. Tenaska will implement the following good combustion, operating, and maintenance practices on the two CCCTs:

Table 10.3-1. Good Combustion, Operating, and Maintenance Practices

Good Combustion Technique	Practice	Standard
Operator practices	• Official documented operating procedures, updated as required for equipment or practice change. • Procedures include startup, shutdown, malfunction • Operating logs/record keeping	• Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, and malfunction.
Maintenance knowledge	• Training on applicable equipment & procedures.	• Equipment maintained by personnel with training specific to equipment.
Maintenance practices	• Official documented maintenance procedures, updated as required for equipment or practice change • Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved • Maintenance logs/record keeping	• Maintain site specific procedures for best/optimum maintenance practices • Scheduled periodic evaluation, inspection, overhaul as appropriate.
Fuel quality analysis and fuel handling	• Monitor fuel quality • Fuel quality certification from supplier if needed • Periodic fuel sampling and analysis • Fuel handling practices • Tenaska will use pipeline quality natural gas	• Fuel analysis where composition could vary • Fuel handling procedures applicable to the fuel.

10.5.3. Step 2 – Eliminate Technically Infeasible Options

As discussed above, CCS is deemed technically infeasible for control of GHG emissions from the combustion turbines. However, Tenaska has decided to perform an economic feasibility analysis for the use of CCS on the CO_2 emissions from the two CCCTs. All other control options discussed above are technically feasible.

10.5.4. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The following remain as technically feasible control options or, in the case of CCS, a control option that Tenaska has chosen to carry forward in the BACT analysis despite infeasibility concerns, for minimizing GHG emissions from the combustion turbines:

- Carbon Capture and Sequestration (CCS);
- Evaporative cooling;
- Selection of efficient CCCTs;
- Fuel selection; and
- Implementation of good combustion, operating, and maintenance practices.

Ranking the above control options is unnecessary because Tenaska proposes to implement all of these control options, except for CCS, based on the environmental, energy, and economic analysis discussed in Step 4.

10.5.5. Step 4 – Evaluate Most Effective Control Options

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. For all identified control technologies except CCS, Tenaska has not identified any adverse energy, environmental, or economic impacts.

As discussed in Sections 10.5.2 and 10.5.3, CCS is considered technically infeasible for the proposed project. However, Tenaska has opted to include a cost feasibility assessment for use of CCS for completeness . The following analysis of the environmental and economic impacts from implementing CCS deems this control option infeasible. The costs associated with CCS can be broken down into the same three categories that the CCS process is divided: CO_2 Capture, CO_2 Transport, and CO_2 Storage. The CCS cost estimation presented in this document is primarily based on cost factors obtained from the CCS Task Force Report. The cost analysis carried out in this report identifies a range of costs associated with each component of CCS (i.e., capture, transport, and storage). To be conservative, the lowest, most applicable factors are taken for use in the cost estimation presented herein. It should also be noted that for this analysis, the factors which appear in the CCS Task Force Report have been converted from a metric tons basis to a short tons basis and escalated from December 2009 dollars to December 2012 (current) dollars using appropriate price indices.[39] The original values as published in the CCS Task Force Report as well as the adjusted values are shown in Table 10.3 below.

Capture and compression costs vary widely depending on what type of combustion equipment and process is used at the facility. Of the power plant configurations for which cost factors are provided in the CCS Task Force Report, the factor for a new natural gas combined cycle facility is taken to be the most applicable. Capture and compression costs typically use either a "CO_2-Captured" or a "CO_2-Avoided" basis. The CO_2-captured basis accounts for all CO_2 that is removed from the process as a result of the installation and use of a control technology, without including any losses during transport and storage or emissions from the control technology itself. A CO_2-avoided basis takes into account the CO_2 losses during transport and storage as well as CO_2 emissions from equipment associated with the implementation of the CCS system. It is more appropriate to use the CO_2 captured monetary estimates because the BACT analysis is based on emissions from a single source (i.e., the direct emissions from the CCCTs) and does not account for secondary emissions (e.g., the GHG emissions generated from the act of compressing the CO_2 to pipeline pressures). As such, the cost factor which uses a CO_2-captured basis is selected for use in this analysis.

The CO_2 transport costs presented in the CCS Task Force Report (i.e., \$1.00 per tonne CO_2) are based on a pipeline length of 100 km (62 miles). It is assumed that this factor may be linearly scaled up for longer pipeline lengths. The hypothetical length of a CO_2 pipeline associated with the proposed project is 106 miles (the minimum distance to the

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[39] Price indices for December 2009 and December 2012 are obtained from the Consumer Price Index published by the U.S. Bureau of Labor Statistics. CPI values obtained from historic tables. Accessed online 3/16/2012 at http://www.bls.gov/cpi/tables.htm.

nearest pipeline or EOR site). As such, the CO_2 transport cost factor from CCS Task Force Report has been adjusted upward proportionally for this consideration.

As presented in the CCS Task Force Report, the costs associated with storage of CO_2 show large variability. The CCS Task Force Report presents a cost range of $0.40 up to $20.00 per tonne of CO_2 stored. While a cost of forty cents per tonne may be an underestimation, it is conservatively taken as the appropriate cost factor for this cost estimate.

Table 10.3. Cost Evaluation of CCS

Carbon Capture and Storage (CCS) Component	Approximate Cost Factors (ACF) ($/tonne CO_2 removed, 08/10 Dollars)	Adjusted ACF ($/ton CO_2 removed, 12/2012 Dollars)[1]	Basis
Capture - NGCC	114.00	108.57	CO_2 Captured
Transport	4.00	2.67	CO_2 Transported per 106 miles of pipeline
Storage	0.40	0.38	CO_2 Stored
Total Cost For Capture, Transport, and Storage	$118.40	$111.61	CO_2 Captured, Transported, and Stored

The original and adjusted cost factors as well as the overall estimated cost of CCS implementation at the Brownsville Generating Station are shown in Table 10.3 above. The overall estimated cost of CCS implementation represents the sum of the individual cost factors. As shown in the table, the estimated cost of CCS implementation at the Brownsville Generating Station is $111.61/ton of CO_2 removed. This equals approximately $523 million/yr (includes installation, operation, and maintenance costs for CCS) based on the annual CO_2 emissions controlled by implementing CCS. The capital cost for the proposed Brownsville Generating Station is approximately $500 million. Using the same cost factors as CCS cost, the ammortized capital cost for the proposed project is approximately $52 million/yr (including annual operation and maintenance costs). Based on these cost estimations, **implementation of CCS will cost Tenaska almost 10 times the project capital cost on an annual basis, which is economically infeasible**. The detailed CCS cost analysis and comparison with project capital costs are presented in Appendix C of this application.

The following Table 10.4 summarizes the cost per ton of CO_2 avoided as represented in other GHG PSD applications for combined cycle power plants in U.S. EPA Region 6.

Table 10.4. Summary of Cost per ton of CO_2 Avoided from other CCCT Plants

Facility	$/ton of CO_2 avoided
La Paloma Energy Center	$91.82
Energy Transfer	$414.81
Calpine Energy Deer Park, TX	$122.22
Calpine Energy Pasadena, TX	$122.22
Apex Bethel Energy Center	$185
Air Liquide – Pasadena, TX	$66

The cost estimated for the proposed CCCTs is consistent with the costs estimated in other permit applications. All these applications deemed CCS as economically infeasible.

The following is a list of the site specific safety or environmental impacts associated with a potential CO_2 removal system.

1. **Economic Feasibility**: The low purity and concentration of CO_2 in the combustion turbines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel power facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of $256 per ton for a new natural gas combined cycle facility, assuming a conservative $6/MMBtu gas price means added cost to the project over $200,000,000 per year.[40]
2. **Energy and Emissions Penalty**: Published studies mentioned elsewhere in this response estimate energy penalties in the range of 15% to 30% of produced energy for CCS. This would also mean that approximately 15% - 30% more fuel will be consumed and up to an additional 15% - 30% of CO_2 per year will be produced (based on total fuel used for 2 CCCTs). This equates to burning up to an additional 16,133 MMscf/yr of natural gas per year (using a 30% energy penalty) and produces additional combustion emissions as listed below,

   - 951,028 tons of CO_2 per year
   - 490 tons of CO per year
   - 89 tons of NO_X per year
   - 20 tons of $PM/PM_{10}/PM_{2.5}$ per year
   - 6 tons of SO_2 per year
   - 157 tons of VOC per year
   - 4 tons of H_2SO_4 Mist per year
   - 108 tons of NH_3 per year
   - 5 tons of HAPs per year.

   The combustion emissions from the additional natural gas usage are calculated based on the emission calculation methods used to estimate emissions from the CCCTs.

3. **Long-term Storage Uncertainty**: A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas.[41] The liability of underground CO_2 storage, however, is less understood. A recent publication from MIT states that "The characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability."[42]

As such, Tenaska contends that CCS is economically infeasible control technology option and eliminates CCS from further review under this BACT analysis.

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[40] Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC

[41] Benson, S. 2006. CARBON DIOXIDE CAPTURE AND STORAGE, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations. Lawrence Berkley National Laboratory

[42] de Figueiredo, M., 2007. The Liability of Carbon Dioxide Storage, Ph.D. Thesis, MIT Engineering

10.5.6. Step 5 – Select BACT for the CCCTs

Tenaska proposes the following design elements and work practices as BACT for the combustion turbines:

- Evaporative cooling design;
- Installation of one or two MHI 501GAC CCCTs along with duct burners for peak capacity;
- Use of pipeline-quality natural gas as fuel; and
- Implementation of good combustion, operating, and maintenance practices.

The proposed BACT limit is determined by applying a "reasonable margin of compliance" to the "new and clean" design net base heat rate established for 2-on-1 scenario. The margin of compliance accounts for the following degradation factors:

- A 3.3% design margin to reflect that the baseline performance values for the HRSGs and steam turbine generators are preliminary estimates absent equipment supplier commercial guarantees and that the equipment as constructed and installed may not fully achieve the assumptions that went into the design calculations,
- A 6% reasonable performance degradation margin to reflect normal wear and tear over the life of the combustions turbines, HRSGs, and steam turbine generators, and
- A 3% reasonable degradation margin based on normal wear and tear over the life of the auxiliary plant equipment (e.g., cooling towers).

Tenaska proposes a combined cycle combustion turbine BACT limit as 914 lb of $CO_2/MW\text{-}hr_{gross,}$ for each CCCT. This value includes the degradation factors discussed above. The proposed BACT limit is below the emission limit of 1,000 lb of $CO_2/MW\text{-}hr_{gross,}$ included in the proposed NSPS Subpart TTTT. The proposed BACT limit applies at combined cycle baseload, with duct burners, at ISO conditions (standard pressure of 14.696 psia and temperature at 60 degree F) corrected for plant elevation, and not accounting for transformer losses and balance of plant auxiliary loads. In addition, Tenaska proposes CO_2e emission limit of 1,577,254 tpy CO_2e for each of the two CCCTs for normal operations. The proposed emission limit is based on a 12-month rolling average basis and includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

The proposed GHG BACT limit for startup and shutdown events is good operating practices that lead to the minimization of startup and shutdown durations. As discussed above, many factors can influence the duration with most being beyond the control of the plant. Therefore, a numerical emissions limit would need to be so conservative, as to allow for the worst-case startup conditions, that it would be rather meaningless for the majority of these events.

Compliance with the proposed BACT limits during normal operations will be demonstrated based on periodic performance testing conducted at base load, corrected to ISO conditions, and not accounting for transformer losses and balance of plant auxiliary loads. Tenaska proposes to conduct the performance test at a frequency of at least once every 25,000 hours of operation of each CCCT block.

In addition, Tenaska proposes to monitor and record the following parameters and summarize the data on a calendar month basis, to demonstrate continuous compliance with the applicable emission limits:

- Fuel for the CCCTs will be limited to pipeline-quality natural gas. The gross calorific value of the fuel will be determined monthly by the procedures contained in 40 CFR part 75, Appendix 5.5.2.
- A fuel flow meter will be installed, calibrated, and operated for each CCCT and the fuel flow meter will comply with the applicable requirements, including certification testing, of 40 CFR Part 75, Appendix D and 40 CFR Part 60.

- The energy output (MWh (gross)) will be measured and recorded on an hourly basis at the generator terminals.
- The amount of actual CO_2 emitted from the CCCTs in tpy will be calculated using applicable equations in 40 CFR Part 98 Subpart C. Compliance with the emission limits will be evaluated based on a 12-month rolling total.
- Calculated CO_2 emissions from normal, unfired, baseload operations will be divided by the gross hourly energy output ($MW\text{-}hr_{gross}$) to determine emissions in terms of lb of $CO_2/MW\text{-}hr_{gross,}$ and compared with the proposed BACT emission limit of 914 lb of $CO_2/MW\text{-}hr_{gross}$.
- Emissions of CH_4 and N_2O will be calculated based on the fuel flow and applicable equations in 40 CFR Part 98 subpart C. Compliance with the emission limits will be evaluated based on a 12-month rolling total.
- Operating hours for the CCCTs with and without duct burners will be monitored.
- The number, type, date, and duration of each start-up and shutdown event for the CCCTs will be monitored and recorded.

10.6. FIRE PUMP ENGINE AND EMERGENCY GENERATOR

The proposed project will comprise of one 500-hp diesel fired fire pump engine and one 2,000 kW diesel fired emergency generator. The fire pump engine and the emergency generator will be limited to 100 hours of operation per year per unit for purposes of maintenance and testing. $CO_{2,}$ CH_4, and N_2O emissions from these units are produced from the combustion of diesel fuel.

The following sections present a BACT evaluation of GHG emissions from the emergency generator engine and the fire pump.

10.6.1. Step 1 - Identify All Available Control Technologies

The available GHG emission control strategies for emergency generator and fire pump that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration (CCS);
- Selection of fuel efficient engine;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices.

10.6.1.1. Carbon Capture and Sequestration

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

10.6.1.2. Efficient Engine Design

Since Tenaska is proposing to install a new fire pump and a new emergency generator, the equipment is designed for optimal combustion efficiency. Additionally, these units are designed to meet the emergency requirements at the Brownsville Generating Station.

10.6.1.3. Fuel Selection

The only technically feasible fuel for the fire pump and the emergency generator is diesel fuel. While natural gas-fueled fire pumps may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the fire pump and emergency generator since it will need to be used in the event of fire, when natural gas supplies may be interrupted.

10.6.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the fire pump and emergency generator per the manufacturer's specifications.

10.6.2. Step 2 - Eliminate Technically Infeasible Options

As discussed above, CCS is not technically feasible for the emergency equipment. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis. As explained above, the only technically feasible fuel for the fire pump and emergency generator is diesel fuel. All other control technologies are considered feasible.

10.6.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Tenaska will select a fire pump and an emergency generator with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

10.6.4. Step 4 - Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

10.6.5. Step 5 - Select CO_2 BACT for Fire Pump and Emergency Generator

Based on the selection of a fuel efficient fire pump and emergency generator and implementing work practice standards including good combustion, operating and maintenance practices. These include:

- Fire pump and emergency generator internal combustion engines (ICE) certified by the manufacturer will be purchased to meet applicable emission standards under NSPS and MACT regulations.
- A non resettable hour meter will be installed and hours of operation will be recorded.
- Operation of the fire pump and emergency generator, for purposes of maintenance checks and readiness testing (per recommendations from the government, manufacturer/vendor, or insurance), will be limited to 100 hours per year for each unit.
- The fuel combusted in the fire pump engine and emergency generator will be calculated using the hours of operation and maximum hourly fuel flow rate.
- The fire pump engine and emergency generator will be tuned for thermal efficiency on an annual basis.

Tenaska will maintain reports and documents of fire pump engine and diesel emergency generator, including but not limited to the following; records pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator and the fire pump engine.

10.7. FUEL GAS HEATER AND AUXILIARY BOILER

The Brownsville Generating Station will include one natural gas-fired fuel gas heater (FIN/EPN: 6) with a maximum rated heat input of 10 MMBtu/hr HHV. In addition to the fuel gas heater, the site will have an auxiliary boiler (FIN/EPN: 7). CO_2, CH_4, and N_2O emissions from the fuel gas heater and auxiliary boiler are produced from the combustion of natural gas.

The following sections present a BACT evaluation of GHG emissions from the fuel gas heater and the auxiliary boiler.

10.7.1. Step 1 - Identify All Available Control Technologies

The available GHG emission control strategies for fuel gas heater and auxiliary boiler that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Selection of fuel efficient gas heater and auxiliary boiler;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices.

10.7.1.1. Carbon Capture and Sequestration

CCS is not feasible solely for small combustion units such as the 10 MMBtu/hr HHV and 90 MMBtu/hr HHV units proposed with this project. However, since the proposed project also include large combustion sources (i.e., CCCTs), it is potentially feasible to capture and transfer CO_2 emissions from these units. As discussed in Section 10.5.5 CCS is not an economically or environmentally feasible option. Therefore, this option is not evaluated in the subsequent analysis.

10.7.1.2. Efficient Engine Design

Since Tenaska is proposing to install a new fuel gas heater and auxiliary boiler, the equipment is designed for optimal combustion efficiency. In addition, the size of the fuel has heater and auxiliary boiler is determined based on the plant's operational requirements and optimal use of these units.

10.7.1.3. Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for the combustion sources. The proposed fuel gas heater and auxiliary boiler will be fired with only natural gas as fuel.

10.7.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the equipment. Good combustion practices include proper maintenance, maintaining good fuel mixing in the combustion zone, and maintain proper air/fuel ratio to facilitate complete combustion.

10.7.2. Step 2 - Eliminate Technically Infeasible Options

As explained above, CCS is not evaluated as a feasible option for the fuel gas heater and auxiliary boiler. All other control technologies are considered feasible.

10.7.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Tenaska will select fuel gas heater and auxiliary boiler with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

10.7.4. Step 4 – Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

10.7.5. Step 5 – Select CO_2 BACT for Fuel Gas Heater and Auxiliary Boiler

Based on the selection of an efficient fuel gas heater and auxiliary boiler and implementing good combustion, operating and maintenance practices, Tenaska proposes a CO_2e BACT limit of 5,125 tons per year for fuel gas heater and 23,061 tons per year for auxiliary boiler, on a 12-month rolling average basis.

Compliance with these emission limits will be demonstrated by monitoring fuel usage and performing calculations consistent with the calculations included in Appendix A of this application.

Compliance with the requested BACT limits demonstrated through the following operational, monitoring and recordkeeping requirements:

- CO_2 emitted from the fuel gas heater and auxiliary boiler will be calculated on a monthly basis using equations in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in 40 CFR Part 98 and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- The higher heating value (HHV) of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the fuel gas heater and auxiliary boiler will be measured and recorded using a flow meter. Flow meters will be calibrated according to manufacturer's recommendations.
- The fuel gas heater and auxiliary boiler will be tuned for thermal efficiency according to manufacturer's recommendations.

Tenaska will maintain reports and documents of fuel gas heater and auxiliary boiler, including but not limited to the following; records pertaining to maintenance performed, all records relating to performance tests and monitoring of the fuel gas heater and auxiliary boiler equipment results.

10.8. FUGITIVE COMPONENTS

The following sections present a BACT evaluation of fugitive CH_4 emissions. Piping components that produce fugitive emissions at the proposed project include: valves, pressure relief valves, pump seals, compressor seals, and sampling connections.

GHG emissions from leaking pipe components (fugitive emissions) from the proposed project include CH_4 and CO_2. The ratio of CO_2 to CH_4 in pipeline-quality natural gas is relatively low. For purposes of the GHG calculations, it was assumed all piping components are in a rich CH_4 stream.

10.8.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified:

- Installing leakless technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an AVO monitoring program for compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

10.8.2. Step 2 - Eliminate Technically Infeasible Options

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions.

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

Leaking fugitive components can be identified through AVO methods. Natural gas leaks from components at the proposed facility are expected to have discernible odor to some extent, making them suitable for detection by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

10.8.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv, accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97%.

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

10.8.4. Step 4 – Evaluate Most Effective Control Options

With leakless components eliminated from consideration, Tenaska proposes to implement the most effective remaining control option. Instrumented monitoring implemented through the 28 MID LDAR program, with control effectiveness on 97%, is considered top BACT. An AVO program to monitor leaks also has a control effectiveness of 97% for most components. Tenaska has chosen to implement an AVO program to monitor fugitive emissions from natural gas service piping components. The proposed project will also utilize high quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed. Since Tenaska is implementing the most effective control options available, additional analysis is not necessary.

10.8.5. Step 5 – Select CH_4 BACT for Fugitive Emissions

Fugitive CH_4 is the major component of the GHG emissions from piping components; Tenaska proposes to implement a work practice as BACT. The AVO program will be used to detect any leaks and repairs will be performed as soon as practicable.

10.9. CIRCUIT BREAKERS

Sulfur hexafluoride (SF_6) gas is used in the circuit breakers associated with electricity generation equipment. Potential sources of SF_6 emissions include equipment leaks from SF_6 containing equipment, releases from gas cylinders used for equipment maintenance and repair operations, and SF_6 handling operations. The following section proposes appropriate GHG BACT for SF_6 emissions.

10.9.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling and reducing SF_6 emissions from circuit breakers, permits and permit applications and EPA's RBLC were consulted. In addition, currently available literature was reviewed to identify emission reduction methods.[43,44,45] Based on these resources, the following available control technologies were identified:

- Use of new and state-of-the-art circuit breakers that are gas-tight and require less amounts of $SF_{6;}$
- Evaluating alternate substances to SF_6 (e.g., oil or air blast circuit breakers);
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

10.9.2. Step 2 - Eliminate Technically Infeasible Options

Of the control technologies identified above, only substitution of SF_6 with other non-GHG substances is determined as technically infeasible. While dielectric oil or compressed air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of SF_6 circuit breakers. In addition, per the EPA,

"No clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[46]

All other control technologies are technically feasible. Tenaska proposes to implement these methods to reduce and control SF_6 emissions.

10.9.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Since Tenaska proposes to implement feasible control options, ranking these control options is not necessary.

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[43] 10 Steps to Help Reduce SF_6 Emissions in T&D, Robert Mueller, Airgas Inc., available at: http://www.airgas.com/documents/pdf/50170-120.pdf.
[44] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.
[45] SF^6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), June 2006, available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.
[46] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, U.S. Environmental Protection Agency, December 2008, available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

10.9.4. Step 4 – Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the aforementioned technically feasible control options.

10.9.5. Step 5 – Select SF_6 BACT for Circuit Breakers

Tenaska proposes the following work practices as SF_6 BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission [IEC]);
- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6 gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

APPENDIX A

GHG Emission Calculations

SITE-WIDE EMISSIONS SUMMARY FOR GHG EMISSIONS

Annual Potential GHG Emissions

EPN	Emission Point Description	Pontentual GHG Emissions (short tons per year)				
		CO_2	CH_4	N_2O	SF_6	Total CO_2e [1]
1	Combustion Turbine 1/Duct Burner - Normal Operations	1,570,399.4	105.57	40.099	-	1,585,046
1	Combustion Turbine 1/Duct Burner - MSS Operations	-	1,604.40	-	-	33,692
2	Combustion Turbine 2/Duct Burner - Normal Operations	1,570,399.4	105.57	40.099	-	1,585,046
2	Combustion Turbine 2/Duct Burner - MSS Operations	-	1,604.40	-	-	33,692
4	Fire Pump Engine	31.2	1.3E-03	2.52E-04	-	31
5	Emergency Generator	155.1	6.3E-03	1.26E-03	-	156
6	Fuel Gas Heater	5,119.7	0.10	0.010	-	5,125
7	Auxiliary Boiler	23,038.6	0.43	0.044	-	23,061
FUG_GHG	Fugitive SF_6 Circuit Breaker Emissions	-	-	-	0.005	122
FUG_GHG	Components Fugitive Leak Emissions	-	1.02	-	-	21
	Total GHG Emissions - 1 on 1 Scenario	**1,598,744.0**	**1,711.52**	**40.155**	**0.005**	**1,647,254**
	Total GHG Emissions - 2 on 1 Scenario	**3,169,143.4**	**3,421.49**	**80.254**	**0.005**	**3,265,993**

[1] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310
SF_6	23900

[2] Percent Contribution (%) = Total CO_2e for each EPN (tpy) / Total CO_2e (tpy) * 100

[3] Proposed BACT limits are rounded upto the nearest digit.

GHG EMISSION CALCULATIONS FOR COMBUSTION TURBINES - NORMAL OPERATIONS

FIN: 1 & 2
EPN: 1 & 2
Mitsubishi MHI 501GAC Combustion Turbines in 1x1 or 2x1 Combined-Cycle Configuration

Input Data[1]

Parameter	Value	Units
Annual Hours of Operation per Turbine[1]	8,760	hr/yr
Annual Maximum Hours of Operation w/o Duct Burner[1]	3,560	hr/yr
Annual Maximum Hours of Operation w/ Duct Burner[1]	5,200	hr/yr
Rated Output of Each Combustion Turbine at 20 deg F, Unfired[2]	305	MW
Rated Output for Steam Turbine, 1x1 Fired Configuration[2]	174	MW
Rated Output of 1x1 Combined Cycle Configuration, Fired at 20 ^{o}F[2]	479	MW
Combustion Turbine Capacity (HHV basis)[2]	2,903	MMBtu/hr/turbine
Duct Burner Capacity (HHV basis)[2]	250	MMBtu/hr
Total Combustion Turbine Capacity (HHV basis, each turbine)[2]	3,153	MMBtu/hr/turbine
Natural Gas High Heat Value, Site-Info (HHV)[2]	1,027	btu/scf
Number of Turbines	2	(for 2 x 1 scenario)

1 Hours of operation data provided by Mr. Larry Carlson (Tenaska) via email to Ms. Latha Kambham (Trinity Consultants) on October 24, 2012.
2 Turbine and duct burner capacity and site-specific natural gas HHV are based on MHI 501GAC model data provided by Mr. Larry Carlson (Tenaska) via email to Ms. Latha Kambham (Trinity Consultants) on January 17, 2013, February 5, 2013 and February 11, 2013.

Proposed Hourly and Annual Emissions - GHG Pollutants - Based on Vendor Data

Pollutant	Hourly Emissions per Turbine[1] Without Duct Burner (lb/hr)	Hourly Emissions per Turbine[1] With Duct Burner (lb/hr)	Annual Emissions for 1x1 Scenario[2] (metric tpy)	Annual Emissions for 2x1 Scenario (metric tpy)	Annual Emissions for 1x1 Scenario[3] (short tpy)	Annual Emissions for 2x1 Scenario (short tpy)
CO_2	341,162.0	370,435.0	1,424,657.0	2,849,314.0	1,570,399.4	3,140,798.8
CH_4	21.77	25.70	95.77	191.54	105.57	211.14
N_2O	8.710	9.460	36.378	72.756	40.10	80.198
CO_{2e}	344,319	373,907	1,437,944	2,875,888	1,585,046	3,170,092

1 Emissions data for combustion turbines provided by Mr. Larry Carlson (Tenaska) via email to Ms. Latha Kambham (Trinity Consultants) on February 5, 2013. Emission data are based on MHI 501 GAC combustion turbine.
2 Annual emissions are calculated based on the maximum hourly emissions and hours of operation with and without duct burner, as follows:
Annual Emissions (tpy) =
[Hourly Emission Rate w/o Duct Burner (lb/hr) x Hours of Operation w/o Duct Burner (hrs/yr) + Hourly Emission Rate w/ Duct Burner (lb/hr) x Hours of Operation w/ Duct Burner (hrs/yr)] x (1 ton /2,000 lb) x (1 metric ton/1.1023 short ton)

$$\text{Annual Emissions of } CH_4 \text{ (tpy)} = \left(\frac{21.77 \text{ lb}}{\text{hr}} \Big| \frac{3{,}560 \text{ hr}}{\text{yr}} + \frac{25.70 \text{ lb}}{\text{hr}} \Big| \frac{5{,}200 \text{ hr}}{\text{yr}} \right) * \frac{1 \text{ short ton}}{2{,}000 \text{ lb}} * \frac{\text{metric ton}}{1.1023 \text{ short tor}} = 95.77 \text{ tpy}$$

metric ton to short ton 1.1023 short ton/metric ton
Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

3 Annual Emissions (short tpy) = Annual Emission (metric tpy) * 1.1023 (short ton/metric ton)
To be consistent with the reporting format in GHG Mandatory Reporting Rule, the emissions rounded as follows: CO_2 - 1 decimal place, CH_4 - 2 decimal places, N_2O - 3 decimal places, and CO_2e - rounded to nearest digit.

GHG EMISSION CALCULATIONS FOR COMBUSTION TURBINES - MSS OPERATIONS

Proposed Startup/Shutdown Events and Duration[1]

Parameter	SUSD Event Details Per Turbine				1x1 Scenario	2x1 Scenario
	Hot Start	Warm Start	Cold Start	Cold Cold Start		
Max Annual Starts Per Unit	2	350	2	2	356	712
Startup Duration (hrs)	0.9	2.4	4.0	4.0		
Shutdown Duration (hrs)	0.4	0.4	0.4	0.4		
SU/SD Duration (hrs/yr)	2.6	986	8.8	8.8	1,006	2,012

[1] Information provided by Mr. Larry Carlson (Tenaska) via email to Ms. Latha Kambham (Trinity Consultants) on January 31, 2013.
An auxiliary boiler will be used to reduce the duration of SUSD durations.
A cold cold start is defined as a startup where the unit has not operated during the preceding 96 hours;
A cold start is defined as a startup where the unit has not operated during the preceding 72 hours;
A hot start is defined as a startup when the unit has operated within the previous 8 hours; and
A warm start is a startup that is not hot or cold.

Proposed Methane Emissions During Startup and Shutdown per Turbine[1]

	SUSD Emissions Per Turbine				1x1 Scenario	2x1 Scenario
	Hot Start	Warm Start	Cold Start	Cold Cold Start		
CH_4 Emissions:						
Startup (lbs/start)	1,500	7,600	20,500	20,500	1,604	3,209
Shutdown (lbs/shutdown)	1,300	1,300	1,300	1,300		
Event (lbs/SUSD event)	2,800	8,900	21,800	21,800		
Annual (tpy)	2.8	1,558	21.8	21.8		
Annual CO_2e (tpy)					**33,692**	**67,385**

[1] Information provided by Mr. Larry Carlson (Tenaska) via email to Ms. Latha Kambham (Trinity Consultants) on January 31, 2013.
CH_4 emissions are assumed to equal to unburned hydrocarbon emissions.
[2] Global Warming Potential of CH_4 = 21 per 40 CFR 98, Subpart A, Table A-1

GHG EMISSION CALCULATIONS FOR OTHER COMBUSTION SOURCES

FINs: 3, 4, 5 & 6
EPNs: 3, 4, 5 & 6

Combustion Sources of GHG Emissions

Parameter	Units	Fire Pump Engine	Emergency Generator	Fuel Gas Heater	Auxiliary Boiler
EPN	-	4	5	6	7
Rated Capacity (HHV) [1]	MMBtu/hr	3.82	19.03	10	90
Hours of Operation per Year [2]	hrs/yr	100	100	8,760	4,380
Natural Gas Potential Throughput [3]	scf/yr	--	--	85,277,148	383,747,167
Diesel Potential Throughput [4]	gal/yr	2,789.80	13,890.51	--	--
Natural Gas High Heat Value (HHV) [5]	MMBtu/scf	--	--	1.027E-03	1.027E-03
Diesel Fuel High Heat Value (HHV) [6]	MMBtu/gal	0.137	0.137	--	--

[1] Rated Capacity for ancillary equipment provided by Mr. Larry Carlson (Tenaska) to Ms. Latha Kambham (Trinity Consultants) on October 22, 2012 and on February 4, 2013.
[2] Annual hours of operation for ancillary equipment provided by Mr. Larry Carlson (Tenaska) to Ms. Latha Kambham (Trinity Consultants) on October 22, 2012.
[3] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value.
[4] Diesel Potential Throughput (gal/yr) = Rated Capacity (MMBtu/hr) * Hours of Operation Per Year (hrs/yr) / Diesel Fuel HHV (MMBtu/gal)

$$\text{Diesel Potential Throughput for Fire Pump Engine (gal/yr)} = \frac{3.82 \text{ MMBtu}}{\text{hr}} \times \frac{100 \text{ hrs}}{\text{yr}} \times \frac{1 \text{ gal}}{0.137 \text{ MMBtu}} = 2789.80 \text{ gal/yr}$$

[5] High Heating Value for Natural Gas represents the site specific HHV.
[6] High Heating Value for Diesel Fuel Oil No.2 is obtained from 40 CFR Part 98, Subpart C, Table C-1.

GHG Emission Factors for Diesel Engine

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for petroleum fuel.

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG EMISSION CALCULATIONS FOR OTHER COMBUSTION SOURCES

FINs: 3, 4, 5 & 6
EPNs: 3, 4, 5 & 6

GHG Potential Emission Calculations

				Hourly Emissions[1] (lb/hr)				Annual Emissions [3,4] (metric tons/yr)				Annual Emissions [5] (short tons/yr)			
EPN	**Description**	**Fuel Type**	**Tier Used**	**CO_2**	**CH_4**	**N_2O**	**CO_2e [2]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e [2]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e [2]**
4	Fire Pump Engine	No.2 Fuel Oil	Tier I	623.24	0.03	0.01	626.97	28.27	1.15E-03	2.29E-04	28	31.2	1.27E-03	2.52E-04	31
5	Emergency Generator	No.2 Fuel Oil	Tier I	3,102.97	0.13	0.03	3,115.00	140.75	5.71E-03	1.14E-03	141	155.1	6.29E-03	1.26E-03	156
6	Fuel Gas Heater	Natural Gas	Tier I	1,168.88	0.02	2.20E-03	1,169.98	4,644.55	0.09	8.76E-03	4,649	5,119.7	0.10	0.010	5,125
7	Auxiliary Boiler	Natural Gas	Tier I	10,519.91	0.20	0.02	10,530.31	20,900.48	0.39	0.04	20,921	23,038.6	0.43	0.044	23,061
			Total	15,415.00	0.38	0.06	15,442	25,714.05	0.49	0.05	25,740	28,344.6	0.54	0.056	28,373

[1] Hourly Emission Rates are calculated based on Annual Emission Rates.
Example Calculation:

Hourly Emissions of CO_2 for Fire Pump Engine (lb/hr) = $\frac{28.27 \text{ metric tons}}{\text{yr}} \left| \frac{1.1023 \text{ short ton}}{\text{metric ton}} \right| \frac{2{,}000 \text{ lb}}{1 \text{ short ton}} \left| \frac{\text{yr}}{100 \text{ hr}} \right.$ = 623.24 lb/hr

tons to lb 2000 lb/ton

metric ton to short ton 1.1023 short ton/metric ton

[2] Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

[3] CO_2 emissions from No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

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

Where:
CO_2= Annual CO_2 mass emissions for the specific fuel type (metric tons).
Fuel = Mass or volume of fuel combusted per year.
HHV = Default high heat value of the fuel.
EF = Fuel-specific default CO_2 emission factor.
1×10^{-3}= Conversion factor from kilograms to metric tons.

[4] CH_4 and N_2O emissions No.2 Fuel Oil and Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

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

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric ton).
Fuel = Mass or volume of the fuel combusted.
HHV = Default high heat value of the fuel.
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).
1×10^{-3}= Conversion factor from kilograms to metric tons.

[5] Annual Emissions (short tpy) = Annual Emission (metric tpy) * 1.1023 (short ton/metric ton)
To be consistent with the reporting format in GHG Mandatory Reporting Rule, the emissions rounded as follows: CO_2 - 1 decimal place, CH_4 - 2 decimal places, N_2O - 3 decimal places, and CO_2e - rounded to nearest digit.

SF_6 EMISSION CALCULATIONS FOR CIRCUIT BREAKERS

FIN: FUG_GHG
EPN: FUG_GHG

SF_6 Emission Rates

EPN	Description	Model Name [1] (kV)	Total Number of Circuit Breakers for Brownsville Station	Amount of SF_6 in Full Charge [1] (lb)	SF_6 Leak Rate [2] (%/yr)	Annual SF_6 Emission Rate [3] (short tons /yr)	Annual CO_2e Emission Rate [4] (short tons/yr)
FUG_GHG	Transmission / Switchyard Breakers	345 kV ABB 362 PM or similar	6	300	0.50	4.50E-03	107.55
	Generator Breakers	Alstom FKG1N G1 or similar	2	66	0.50	3.30E-04	7.89
	Bottle Storage	Large Bottle	1	115	0.50	2.88E-04	6.87
Total						**5.12E-03**	**122**

[1] Information provided by Mr. Larry Carlson (Tenaska) to Ms. Latha Kambham (Trinity Consultants) on October 22, 2012.

[2] From EPA's technical paper titled, "SF6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emission Source - by J. Blackman, Program Manager, U.S. EPA and M. Averyt, ICF Consulting, and Z. Taylor, ICF Consulting". Used the worst-case estimate of 0.5% per year.

[3] Annual Emission Rate (tpy) = Number of Circuit Breakers * Amount of SF_6 in Full Charge (lb) * SF_6 Leak Rate (%/yr) * 1/2000 (ton/lb)

[4] Global Warming Potential (GWP) of SF_6 = 23,900

To be consistent with the reporting format in GHG Mandatory Reporting Rule, the CO_2e emissions are rounded to nearest digit.

FUGITIVE GHG EMISSION CALCULATIONS FOR NATURAL GAS SERVICES

FIN: FUG_GHG
EPN: FUG_GHG

Fugitive GHG Emissions Rates in Natural Gas Services

EPN	Components	Component Count [1]	Emission Factors [2] (lb/hr-component)	Control Efficiency [3] (%)	CH_4 Emissions [4, 5,6] (tons/yr)	Annual CO_2e Emissions [7] (short tons/yr)
FUG_GHG	Valves	624	0.00992	97%	0.79	16.57
	Pressure Relief Valves	12	0.0194	97%	0.03	0.62
	Flanges	1752	0.000860	97%	0.19	4.03
	Pumps	4	0.00529	93%	5.66E-03	0.12
				Total Emissions	**1.02**	**21**

[1] Component counts provided from Mr. Larry Carlson (Tenaska) to Ms. Latha Kambham (Trinity Consultants) on October 22,2012. A 20% safety factor is also included in the fugitive component counts.

[2] Emission factors obtained from Table 4 for Oil and Gas Production Operations from Addendum to RG-360A, *Emission Factors for Equipment Leak Fugitive Components,* TCEQ, January 2008, Gas factors.

[3] The Brownsville Generating Station will implement Audio/Visual/Olfactory (AVO) program to minimize emissions. Control efficiencies are obtained from October 2000 Draft TCEQ Technical Guidance Package.

[4] The methane content in the gas is conservatively assumed to be 97 %.

[5] The annual hours of operation are 8,760 hrs/yr.

[6] Annual Emission Rate (tpy) = Component Count * Emission Factor (lb/hr-component) * Methane Content (%) * Annual Hours of Operation (hrs/yr) * 1/2000 (ton/lb)

$$CH_4 \text{ Annual Emissions from Valves (tpy)} = 624 \text{ components} \times \frac{0.00992 \text{ lb}}{\text{hr - component}} \times \frac{97\ \%}{100} \times \frac{8{,}760 \text{ hrs}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = 0.79 \text{ tpy}$$

[7] Global Warming Potential of CH_4 = 21 per 40 CFR 98, Subpart A, Table A-1

APPENDIX B

Alternative Options Analysis for Duct Burners

Capital Costs for Incremental Nominal 36 MW Plant Capacity Alternatives

Capital Cost Summary		Larger CTs NOT APPLICABLE *(2x1 MHI 501 J Plant size would exceed 800 MW maximum)*	Aeroderivative Simple Cycle CTs (1xLM6000 PF DLE, 35 MW)	Reciprocating Internal Combustion Engines 4 x 10 MW Engines, 37.6 MW Net)	Duct Burners (36 MW)
	Unfired Plant Output, kW		764,000	764,000	764,000
	Incremental Plant Output, kW		36,985	37,635	36,000
	Maximum Plant Output, kW		800,985	801,635	800,000
TOTAL INSTALLED CAPITAL COST (TIC)	**TIC =**		**$55,516,695**	**$46,212,418**	**$4,032,000**

Annual Costs for Incremental Nominal 36 MW Plant Capacity Alternatives

Annual Cost Summary				
DIRECT ANNUAL COSTS				
Operating Hours per day:		20	20	20
Days per year:		260	260	260
Operating & Maintenance				
Fixed		$1,306,622	$1,163,052	$434,160
Variable		$1,367,839	$2,047,790	$241,488
Energy Costs	Heat Rate, Btu/kwh HHV	9,838	8,739	9,500
Fuel Costs		$8,686,737	$8,551,261	$8,645,000
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$11,371,036**	**$11,770,842**	**$9,330,148**
INDIRECT OPERATING COSTS				
General & Administrative Charges (0.554% of TCI)	0.0055	$307,562	$256,017	$22,337
Insurance (0.483% of TCI)	0.0048	$268,146	$223,206	$19,475
Property Taxes (1.5% of TCI)	0.0150	$833,861	$694,111	$60,561
Capital Recovery (CRF x TCI)				
	CRF = 0.1258	$6,985,111	$5,814,446	$507,306
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$8,394,679**	**$6,987,780**	**$609,679**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)	**TAC=**	**$19,765,716**	**$18,758,622**	**$9,939,827**
Cost Effectiveness Summary				
Annual Control Cost:		**$19,765,716**	**$18,758,622**	**$9,939,827**
Incremental Power Output (KW-hr)		**192,322,715**	**195,703,418**	**187,200,000**
Average Cost ($/KW-hr)		**$0.103**	**$0.096**	**$0.053**

APPENDIX C

CCS COST ANALYSIS

Table C-1. Cost Estimation for Transfer of CO_2 via Pipeline to Existing CO_2 Well

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	106	miles
Average Diameter of Pipeline	8	inches
CO_2 emissions from combustion turbines (both CCCTs)	3,140,799	Short tons/yr
CO_2 Capture Efficiency	90%	
Captured CO_2	2,826,719	Short tons/yr

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D² + 686.7 x D + 26,960)	$10,576,690.16
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D2 + 2,074 x D + 170,013)	$41,242,164.78
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$12,639,149.60
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$4,424,225.80
Other Capital			
CO_2 Surge Tank	$	$1,150,636	$1,150,636.00
Pipeline Control System	$	$110,632	$110,632.00
Operation & Maintenance (O&M)			
Fixed O&M	$/mile/yr	$8,632	$914,992.00
		Total Pipeline Cost	**$71,058,490.34**

Amortized Cost Calculation

Equipment Life [2]	20	years
Interest rate [3]	7%	
Capital Recovery Factor (CRF) [4]	0.09	
Total Pipeline Installation Cost (TCI)	$70,143,498	$ (Pipeline + Other Capital)
Amortized Installation Cost (TCI *CRF)	$6,621,050	$/yr
Amortized Installation + O&M Cost	$7,536,042	$/yr
CO_2 Transferred	2,826,719	Short tons/yr
Annuitized control cost per ton [5]	**3**	**$/ton-yr**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[2] Pipeline life is assumed based on engineering judgment.

[3] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

[4] Capital Recovery Fraction = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

[5] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment.

Table C-2. Carbon Capture and Storage (CCS) - Total Costs

Carbon Capture and Storage (CCS) Component System	Cost ($ per ton of CO_2 Controlled)[1,2]	Annual System CO_2 Throughput (Short tons controlled/yr)	Total Annual Cost
CO_2 Capture and Compression System - NGCC[3]	$108.57	2,826,719	$306,890,946
CO_2 Transport Facilities[4]	$2.67	2,826,719	$7,536,042
CO_2 Storage system[5]	$0.38	2,826,719	$1,076,810
Total Cost For Capture, Compression, Transport, and Storage[6]	$111.61	N/A	$525,444,218

[1] Cost Factors are converted from dollars per metric ton to dollars per short ton using a conversion factor of 1 metric ton = 1.1023 short tons.
[2] Costs are from Report of the Interagency Task Force on Carbon Capture (August, 2010). A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost.
[3] The cost factor for post-combustion capture of CO_2 from a Natural Gas Combined Cycle (NGCC) system is selected because it is the most similar process with available cost information to that of the proposed project.
[4] The original cost factor for CO_2 transport obtained from the *Report of the Interagency Task Force on Carbon Capture and Storage* was $1.00 / tonne and is based on a pipeline length of 62 miles. As such, this factor has been linearly adjusted to account for the hypothetical pipeline length (106 miles) associated with the proposed project.

[5] Storage cost includes consideration for initial site screening and evaluation, operation of injection equipment, and post-injection site monitoring. It should be noted that in the *Report of the Interagency Task Force on Carbon Capture and Storage* , storage costs range from $0.4 to $20 / tonne are cited.
[6] Total Cost for implementation of a CCS system equals the sum of the individual Capture, Compression, Transport, and Storage costs.

Table C-3. Comparison of CCS Costs with Project Capital Cost

Project Capital Cost: Amortized Cost Calculation

Equipment Life [1]	20	years
Interest rate [2]	7%	
Capital Recovery Factor (CRF) [3]	0.09	
Total Capital Cost for the proposed Brownsville Generating Station (TCI)	$500,000,000	$ (Equipment and control costs)
O & M Cost (O&M)	$53,000,000	For Equipment life
Amortized Installation Cost (TCI *CRF)	$47,196,463	$/yr
Amortized O & M Cost (O&M *CRF)	$5,002,825	$/yr
Amortized Installation + O&M Cost for the Project	**$52,199,288**	**$/yr (Capital Cost)**
Amortized Installation + O&M Cost for CCS	**$525,444,218**	**$/yr for CCS**
Ratio of CCS Cost to Project Capital Cost on Annual Basis	**10**	**times the capital cost**

[1] Equipment life is assumed based on engineering judgment.
[2] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.
[3] Capital Recovery Fraction = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)
[5] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment.