RPS

411 N. Sam Houston Parkway E., Suite 400, Houston, Texas 77060-3545 USA
T +1 281 448 6188 **F** +1 281 488 6189 **W** www.rpsgroup.com

February 13, 2013

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

RE: **Application for PSD Air Quality Permit**
Greenhouse Gas Emissions
Victoria Power Station
Victoria WLE LP
Victoria, Victoria County, Texas
RN 100214980
CN 602656548
TCEQ Account No. VC-0003-D

Dear Mr. Robinson:

On behalf of Victoria WLE LP (Victoria), RPS is submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions from a new combined cycle combustion turbine to be installed at the Victoria Power Station.

A State NSR and PSD permit application for other regulated pollutants is being submitted to TCEQ simultaneously. Victoria and RPS are committed to working with EPA to ensure a timely review of this permit application. We are available to meet with you at your convenience in your offices to discuss the project and answer any questions you may have.

Should you have questions concerning this application, or require further information, please do not hesitate to contact me at (832) 239-8016 or Ms. Mona Johnson of Victoria at (713) 358-9736.

Yours truly,

Stephen A. Langevin

Stephen A. Langevin
Senior Consultant, RPS

Enclosure

cc: Ms. Melanie Magee, EPA Region 6
Ms. Mona Johnson, Victoria WLE LP
Mr. Shanon DiSorbo, RPS

Cielo Center, 1250 South Capital of Texas Highway, Building Three, Suite 200, Austin, Texas 78746, USA
T +1 512 347 7588 **F** +1 512 347 8243 **W** www.rpsgroup.com

Application for a Prevention of Significant Deterioration Air Permit for Greenhouse Gas Emissions

Victoria WLE LP
Victoria Power Station
Victoria, Victoria County, Texas

February 2013

Table of Contents

List of Sections

Table of Contents (continued)

List of Tables

List of Figures

List of Appendices

Section 1
Introduction

Victoria WLE LP (Victoria) owns the Victoria Power Station in Victoria, Victoria County, Texas. The facility is a combined cycle electric generating station operated in a 1 by 1 by 1 (1X1X1) configuration with a gas turbine (M501F), heat recovery steam generator (HRSG) with duct burners, and a steam generator (General Electric D5). The facility is currently authorized under Standard Permit No. 80878 and several Permits by Rule, including Permit by Rule §106.263 for MSS (Registration Number 94387) and operates under Title V Permit, No. O-35.

Victoria proposes to install an additional natural gas-fired turbine (GT) and HRSG with duct burners at the Victoria Power Station. The resulting new facility will be a combined cycle generating unit in a 2 by 2 by 1 (2X2X1) configuration (two combustion turbines, two HRSGs with duct burners, and one steam turbine). No change to the steam turbine generator will be made, although power generation will be increased due to utilization of orphaned capacity. The proposed gas turbine and duct burner will fire natural gas exclusively. Operation of the existing unit will continue to be in a 1X1X1 combined cycle configuration until the new HRSG and gas turbine construction is completed. Following startup of the new HRSG and gas turbine, the capability to operate the turbines in a 1X1X1 combined cycle mode will be retained.

No modifications to the existing GT/HRSG or steam turbine are proposed. Emission rate increases associated with the installation and operation of the proposed new facilities and affected existing facilities are included in this application. A new chiller will replace the existing evaporative cooler used with the existing turbine to allow the existing turbine to operate more efficiently during the summer months. Although it is an affected source, the turbine itself will not be modified and will not operate or be capable of operating at rates higher than it is currently capable of and authorized for. Actual emissions will not exceed current permit allowable emissions.

The existing cooling tower will be modified to increase its capacity, and an additional aqueous ammonia (NH_3) storage tank and associated piping will also be installed.

Victoria has submitted an application to TCEQ for an air quality permit for this project that includes all applicable state New Source Review (NSR) requirements and Prevention of Significant Deterioration (PSD) review for nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter ($PM/PM_{10}/PM_{2.5}$). The project emission rate increases also exceed the 75,000 ton per year (tpy) PSD applicability thresholds for greenhouse gases (GHG). Permitting of GHG emissions in Texas is currently conducted by the USEPA Region VI; therefore, a separate PSD permit application is required to be submitted to USEPA for GHG emissions. This document constitutes the application for the required Victoria Power Station GHG PSD permit. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission points with respect to the plant property.

Section 4 contains more details about the proposed modifications and changes in operation and a brief process description and simplified process flow diagram.

Section 5 describes the basis of the calculations for the project GHG emission rate increases and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new and modified sources of GHG emissions.

Appendix A contains the completed TCEQ Federal NSR applicability Tables 1F, 2F and 3F.

Appendix B contains detail GHG emissions calculations for the affected facilities.

Section 2
TCEQ Forms

This section contains the required Administrative Information Form. Federal NSR applicability forms (TCEQ Tables 1F, 2F and 3F) are included in Appendix A.

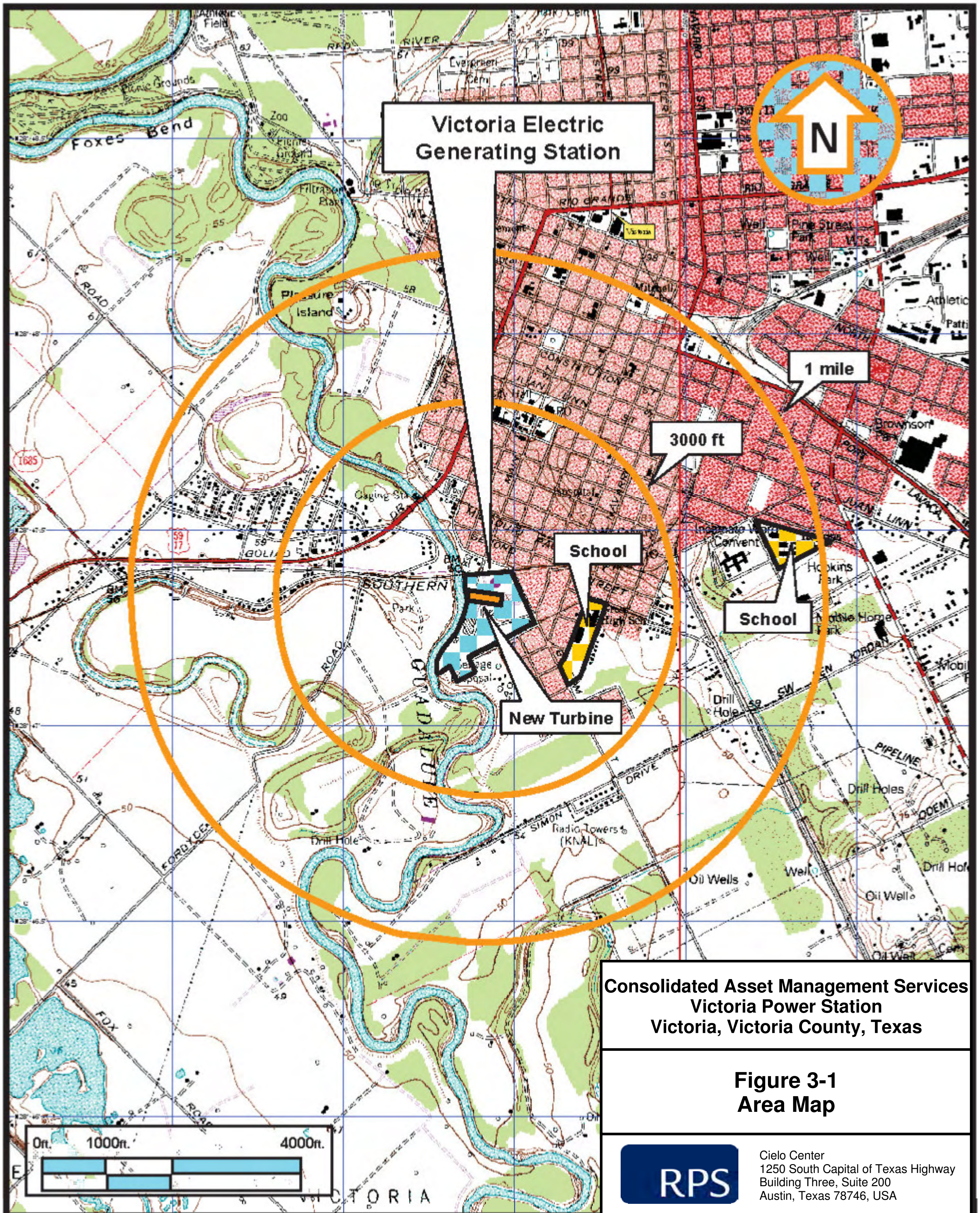
Because this application covers only GHG emissions, and permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of carbon dioxide equivalent (CO_2e); therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: **Victoria WLE, L.P.**		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): **Gary Clark**		
Title: **Asset Manager**		
Mailing Address: **1205 South Bottom Street**		
City: **Victoria**	State: **TX**	ZIP Code: **77901**
Telephone No.: **(361) 947-9934**	Fax No.: **(361) 575-4978**	E-mail Address: **rgclark@camstex.com**
C. Technical Contact Name: **Ms. Mona Johnson**		
Title: **Regulatory & Compliance Manager**		
Company Name: **Consolidated Asset Management Services**		
Mailing Address: **919 Milam, Suite 2300**		
City: **Houston**	State: **TX**	ZIP Code: **77002**
Telephone No.: **(713) 358-9736**	Fax No.: **(713) 358-9730**	E-mail Address: **mjohnson@camstex.com**
D. Facility Location Information:		
Street Address: **1205 South Bottom Street**		
If no street address, provide clear driving directions to the site in writing:		
City: **Victoria**	County: **Victoria**	ZIP Code: **77901**
E. TCEQ Account Identification Number (leave blank if new site or facility): **VC-0003-D**		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: **CN602656548**		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: **RN100214980**		
H. Site Name: **Victoria Power Station**		
I. Area Name/Type of Facility: **Electric Generating Unit**	☒ Permanent ☐ Portable	
J. Principal Company Product or Business: **Electric Services**		
K. Principal Standard Industrial Classification Code: **4911 Electric Services**		
L. Projected Start of Construction Date: **June 1, 2014**	Projected Start of Operation Date: **June 1, 2015**	
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.		
NAME: Mr. Gary Clark, Asset Manager		
SIGNATURE: *Original Signature Required*		
DATE: 2/13/2013		

Section 3
Area Map and Plot Plan

An area map showing the general location of the facility and a 3,000 ft. radius is included as Figure 3-1. Figure 3-2 is a plot plan that shows the location of major equipment and facilities and the emission points at the Victoria Power Station that will be included in this permit.



Consolidated Asset Management Services
Victoria Power Station
Victoria, Victoria County, Texas

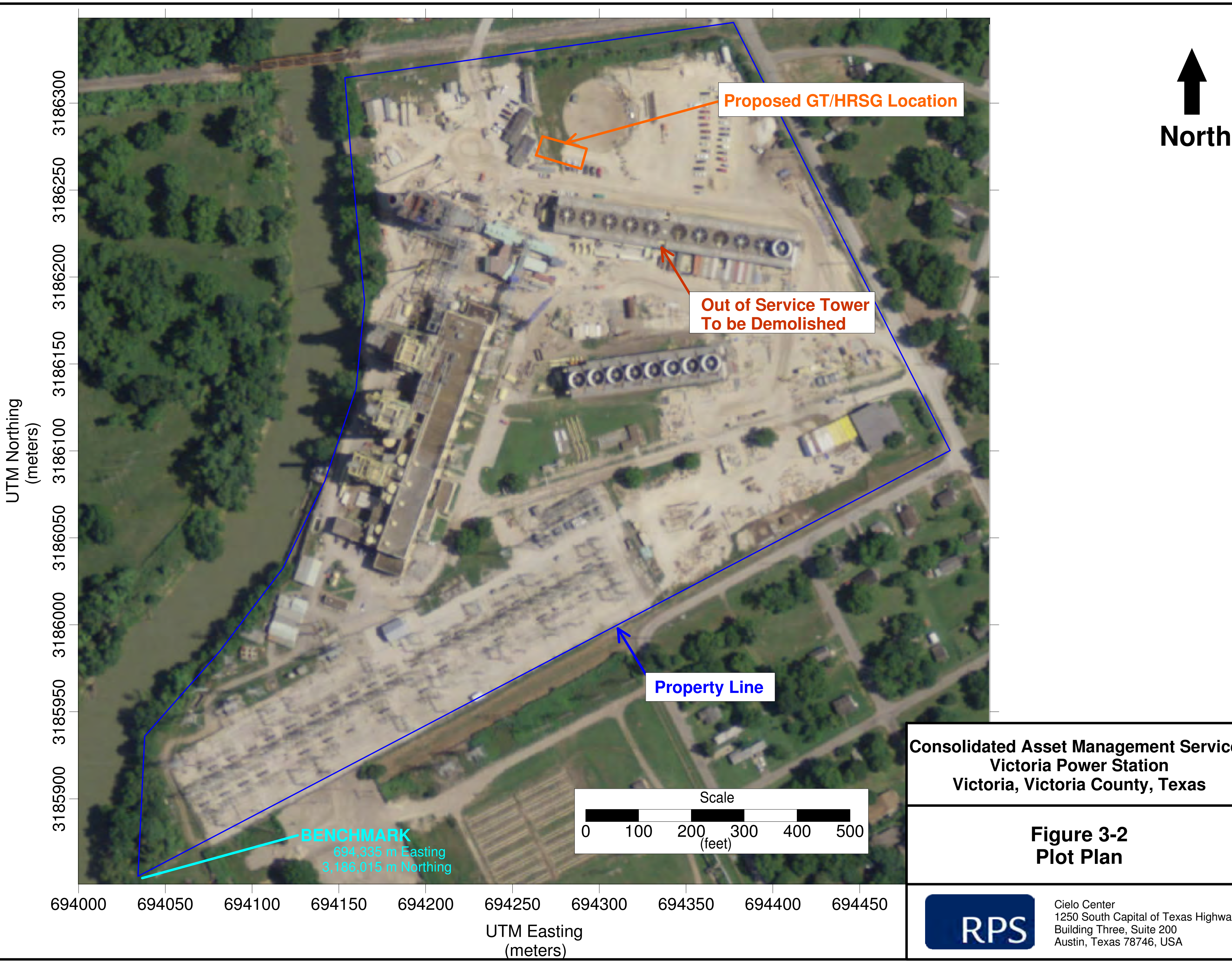
Figure 3-1
Area Map

RPS

Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

3-D TopoQuads Copyright © 1999 DeLorme Yarmouth, ME 04096 Source Data: USGS

700 ft Scale: 1 : 24,000 Detail: 13-6 Datum: WGS84



Consolidated Asset Management Services
Victoria Power Station
Victoria, Victoria County, Texas

Figure 3-2
Plot Plan

RPS

Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Section 4
Project and Process Description

4.1 Electric Generating Units

This project includes the addition of a new gas turbine and a new HRSG (VIC10) with the capability to operate with the existing 1X1X1 combined cycle facility. The resulting operation will be a 2X2X1 combined cycle facility, consisting of two gas turbine-generators (GT), two HRSGs with duct burners, two inlet chillers, one steam turbine generator, and other mechanical and electrical auxiliary systems. The existing cooling tower will be modified to increase its capacity, and an additional aqueous ammonia (NH_3) storage tank and associated piping will also be installed. A process flow diagram (PFD) for the facility is shown in Figure 4-1.

The current facilities will continue to be authorized by the Standard Permit. No modifications to the existing turbine/HRSG or steam turbine are proposed; however, the new inlet chiller will allow the existing turbine to operate more efficiently in the summer months. The turbine itself will not be modified and will not operate or be capable of operating at rates higher than it is currently capable of and authorized for. Therefore, the existing turbine is only considered to be an “affected unit” for this project. Actual emissions will not exceed current permit allowable emissions.

The following process description is for the facility operating in combined cycle mode at 100% load with the average ambient temperature at approximately 60°F and 60% percent relative humidity. The operations will vary with the ambient temperature, relative humidity, and load conditions. In addition, the values presented below are approximate and are subject to change per final design. The existing combustion turbine and steam turbine will continue to operate in a combined cycle mode in a 1X1X1 configuration prior to completion of construction of the new gas turbine and HRSG. This capability will be maintained permanently.

The new GHG emission sources associated with the proposed project are one gas turbine/HRSG exhaust stack and potential fugitive emissions of methane from natural gas piping components. The hot exhaust gas from the GT will be directed to a dedicated HRSG where thermal energy will be recovered to generate steam in the steam turbine. Supplemental firing capability will be available in the HRSG. The GT and HRSG duct burners will be fired exclusively with natural gas.

The GT and HSRG duct burner exhaust will be fitted with a selective catalytic reduction (SCR) system for secondary NO_x control. The SCR consists of a catalyst bed and an ammonia injection grid. The catalyst consists of a porous ceramic, honeycomb substrate that has been coated with either a vanadium-titanium or zeolite catalyst. Nineteen percent (19%) aqueous ammonia is injected into the flue gas upstream of the catalyst bed. The catalyst promotes a reaction between flue gas NO_x and the ammonia to convert NO_x into nitrogen and water, thereby reducing NO_x emissions. NO_x emissions will be controlled to 2 ppmvd at 15% oxygen on a 24-hr average. A post-combustion oxidation catalyst will also be installed to control emissions of CO from the GT/HRSG exhaust.

As a result of these changes, the available capacity of the steam turbine will be increased from 125 MW in its existing 1X1X1 configuration to approximately 185 MW in the 2x2x1 configuration.

Total gross design capacity of the plant will increase from approximately 290 MW to 545 MW of generation power. Factoring in the estimated station use of 13 MW, the total net capacity will be approximately 530 MW.

4.1.1 Gas Turbines

The existing GT is a Mitsubishi Heavy Industries 501F turbine with a maximum heat consumption of approximately 1,936 MMBtu/hr (HHV). The installation of an inlet chiller to cool the inlet air to the existing GT (M501F) gas turbine will optimize inlet conditions and allow the gas turbine to operate more efficiently in the summer months. This operating level does not exceed the maximum rate that the turbine is currently capable of operating at and has operated at during cooler winter months.

The new GT will be a General Electric 7FA.04 (GE 7FA) or equivalent. The GE 7FA turbine will have a maximum heat consumption of approximately 1,924 MMBtu/hr (HHV) and a nominal capacity of up to 196.9 MW of power.

The GT will be equipped with lube oil vents, an inlet chiller, rotor air cooling fans, and totally enclosed water to air cooled (TEWAC) generators.

4.1.2 Heat Recovery Steam Generators

The new HRSG with natural gas-fired duct burners to allow for supplemental gas firing will be used to provide additional steam to the steam turbine. The new HRSG will be a natural circulation-type unit similar to the one on the existing facility.

The duct burners will be capable of a maximum natural gas firing rate of up to 483 MMBtu/hr (HHV). The duct burners may be fired additional hours; however, total annual firing will not exceed the equivalent of 4,375 hours at maximum capacity per duct burner. The heat recovery surface of each unit will be finned tube, modular type for efficient, economical heat recovery and rapid field erection. The combined exhaust stream from the new GT and duct burner will be emitted to the atmosphere through one common dedicated stack.

4.1.3 Inlet Air Cooling

The inlet air to the new and existing GT will be cooled during high ambient temperature conditions through the use of chillers. Cooling of the inlet air will increase output of the GT while lowering the heat rate.

4.1.4 Steam Turbine Generator

The existing steam turbine will be driven by the steam produced in the two HRSGs (existing and new) to produce approximately 185 MW of power in the 2X2X1 configuration.

4.2 Condenser and Cooling Tower

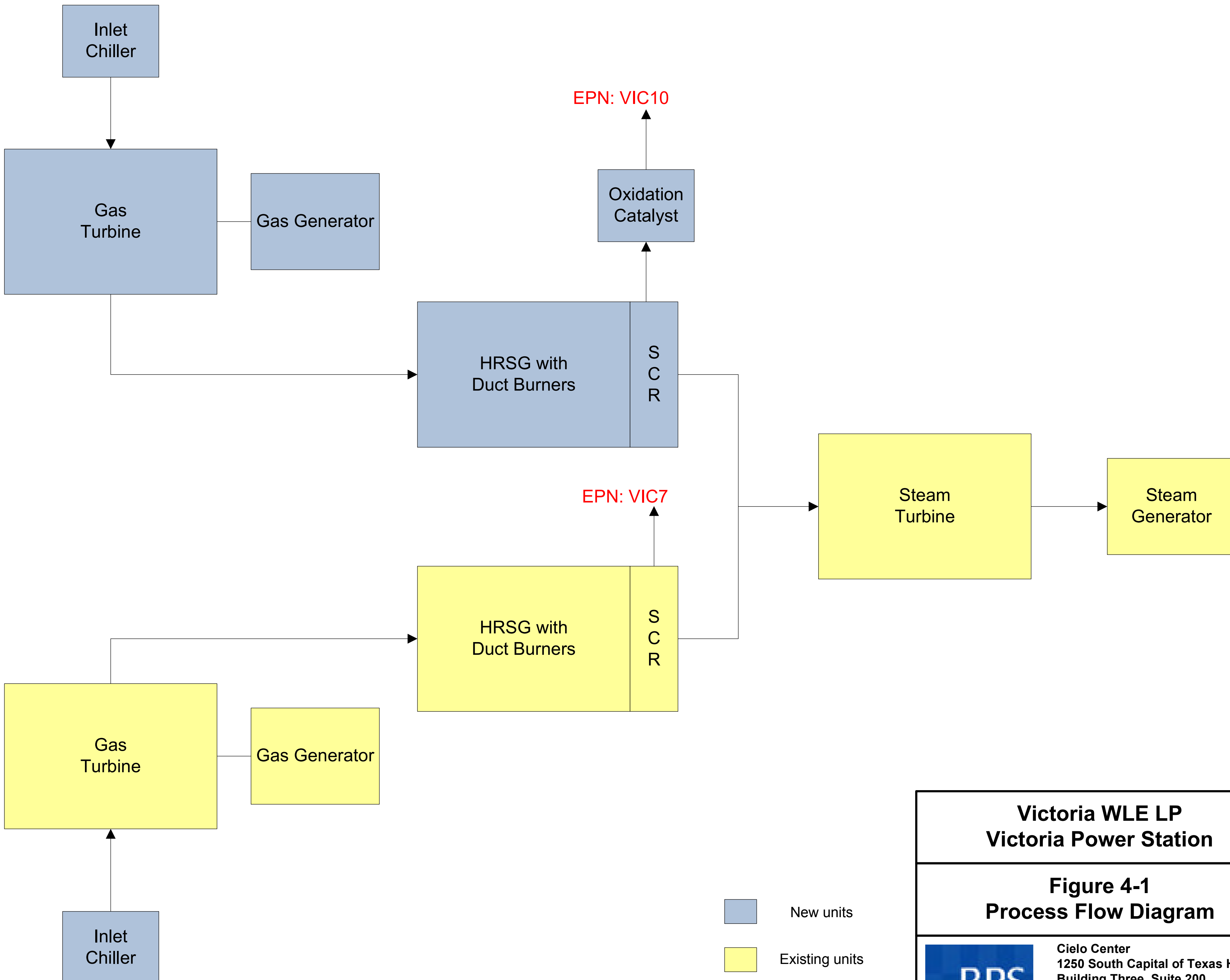
The existing condenser/cooling tower arrangement that cools steam exhausted from the steam turbine will be modified to enhance performance. The condenser is a surface contact heat exchanger and the cooling tower a multi-cell, motor-driven, mechanical draft, counterflow tower with film fill. The existing cooling tower will be modified to have a 197,000 gpm circulation rate and a design drift rate of 0.001%.

The auxiliary cooling water system cools the plant auxiliaries such as the TEWAC generators, lube oil coolers, etc. The auxiliary cooling system uses a cross exchanger to transfer heat to the cooling tower water.

4.3 Emissions Control

The new GT will employ a dry low NOx (DLN) combustion system as the primary method to control NO_X emissions. The dry low NOx system uses lean premix gas nozzle technology and multiple staged fuel nozzles to control flame temperature and promote thorough combustion during the permitted load range.

An SCR system will also be installed at the HRSG to further reduce NO_x emissions from the combined GT/HRSG exhaust. A catalyst bed and an ammonia injection grid are located in a temperature region of the HRSG that will favor the reaction. Ammonia for the SCR will be provided from a new on-site 15,000 gallon aqueous ammonia tank. Associated emissions include potential fugitive leaks from the ammonia piping system as well as ammonia slip. A post-combustion oxidation catalysit will also be installed to control CO emissions from the new GT/HRSG.



Victoria WLE LP
Victoria Power Station

Figure 4-1
Process Flow Diagram

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new and affected facilities associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix B.

5.1 Gas Turbine/Duct Burner

Combustion turbine and duct burner emission rates were calculated for each GHG pollutant: CO_2, CH_4, and N_2O and then converted to CO_2e emission rates. Annual (tpy) emission limits, to be enforced on a 12-month rolling average basis, were calculated for the new generating unit. Because only annual emission rate limits are proposed, the emission representations were based on turbine performance at average annual site conditions of approximately 60 °F and a relative humidity of 60% for Victoria County. The turbine contribution to the annual pollutant emission rates is based on this condition at 100% load for 8,760 hour per year. The duct burner contribution to the annual pollutant emission rates is based on the equivalent of the duct burner system firing at maximum capacity for 4,375 hours per year. The actual duct firing hours may exceed these hours; however, total annual emission rates will not exceed those represented by this scenario.

Emissions of CO_2 were calculated by applying the 40 CFR Part 75, Appendix G, Section 2.3 emission factor of 1,040 scf_{CO2}/mmBtu (118.9 lb/mmBtu) to the total annual firing rates of the turbine and HRSG duct burner system. Emissions of CH_4 and N_2O were calculated using emission factors of 0.001 kg/mmBtu and 0.0001 kg/mmBtu, respectively, from 40 CFR Part 98, Subpart C Table C-2 for natural gas combustion. CO_2e emissions were calculated by multiplying the emission rate of each GHG by the global warming potential factors from 40 CFR Part 98, Subpart A, Table A-1.

During startup of the combustion turbine, emissions of GHGs are not elevated above routine levels; therefore, alternate emission rates were not calculated for these periods. Emissions during startup and shutdown periods will be counted toward the total annual emission rates for the purpose of assessing compliance with the proposed annual CO_2e emission limits.

5.2 Natural Gas Pipeline Fugitives

Fugitive emissions of methane may originate from the natural gas fuel lines that provide fuel to the combustion turbine and the HRSG duct burners. Fugitive emission rates were estimated using the methods outlined in the TCEQ's Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, Draft, October 2000. Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate SOCMI without ethylene emission factor and then applying appropriate control credit.

No control credit was applied for the natural gas fuel lines although periodic walk-through inspections of lines will be made. The methane emission rates for each compound were established by multiplying the total emission rates by the concentration (weight %) of methane in the natural gas. The methane emission rates were then converted to CO_2e emission rates using the global warming potential factor from 40 CFR Part 98, Subpart A, Table A-1.

5.3 SF_6 Emissions from Electrical Equipment Insultation Leaks

Emissions of sulfur hexafluoride (SF_6) due to leaks from the insulation used in new circuit breakers were estimated by applying a 0.5% annual leak rate to the weight of SF_6 estimated to be present in circuit breakers associated with the new facilities (International Electrotechnical Commission Standard 62271-1, 2004).

Table 5-1. Proposed GHG Emission Limits (CO_2e)

EPN	Description	Annual (tpy)
VIC10	Unit 10 Routine Emissions (GE 7FA)	1,071,912.30
VIC10-FUG-NGAS	Unit 10 Natural Gas Fugitive Emissions	373.44
VIC10-INS-SF6	Unit 10 Circuit Breaker Insulation Leaks (SF_6)	1.35

Section 6
BACT Analysis

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emission rate increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project that emit GHGs include the VIC10 natural gas fired GT and associated duct burners, natural gas pipeline fugitives, and SF_6 leaks from circuit breaker insulation. This BACT analysis addresses these emission sources.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (New Source Review Workshop Manual (Draft), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1. Identification of available control technologies;
2. Technically infeasible alternatives are eliminated from consideration;
3. Remaining control technologies are ranked by control effectiveness;
4. Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and
5. Selection of BACT.

In its PSD and Title V Permitting Guidance for Greenhouse Gases (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

6.1 Gas Turbine/HRSG

6.1.1 Step 1 – Identification of Potential Control Technologies

The proposed combustion turbine and duct burners will produce CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents in the natural gas. Small quantities of CH_4 and N_2O will also be emitted based on emission factors required for use in the Mandatory Greenhouse Gas Reporting Rules.

A RACT/BACT/LAER Clearinginghouse (RBLC) database search of CO_2 and CO_2e emissions from large natural gas fired combustion turbines was conducted to identify potential controls and performance standards. No comparable units were identified in the search. Four turbines, all much smaller than the proposed turbine were found, and no performance standards were included in the database. Emission controls were listed as good combustion practices and use of natural gas fuel for all four turbines. Due to the absence of usable information, the results of the search are not included in this permit application. Potentially applicable control technologies were identified for the analysis based on process knowledge, previous permit applications for similar facilities, and EPA guidance.

The proposed VIC10 electric generating facility will be designed and constructed to operate in combined cycle mode. Combined cycle power plants are the most efficient means of generating electric power from the combustion of natural gas, and combustion of natural gas has the lowest GHG emission factor of all available fossil fuels. Thus, the proposed plant design results in the lowest possible GHG emission rate per kwh of electricity generated of all available fossil fuel fired electric generation technologies, prior to consideration of add-on technologies to capture and dispose of the produced CO_2. In a combined cycle configuration, the hot gases in the turbine exhaust are routed through a HRSG to produce steam that is then used to generate additional electricity in a steam turbine; thus, significantly increasing the thermal efficiency of the process compared to a simple cycle configuration. Additional natural gas is commonly burned in duct burners in the HRSG to allow additional steam to be produced for power production by the steam turbine. The proposed VIC10 configuration will include duct firing capability.

Although the combined cycle configuration is inherently efficient, design and operating practices can further improve and maintain that efficiency, and these practices are considered in this BACT analysis. Based on process and engineering knowledge and judgment and permit applications that have been submitted to EPA Region 6 for similar facilities, the following potentially applicable GHG control technologies and operating practices were identified for consideration:

- **Periodic Maintenance and Tune-up** - After several months of continuous operation of the combustion turbine, fouling and degradation contribute to a loss of thermal efficiency. A periodic maintenance program consisting of inspection and cleaning of key equipment components and tuning of the combustion system will minimize performance degradation and recover thermal efficiency to the maximum extent possible. The manufacturer of the proposed turbine has developed a periodic inspection and maintenance program that is based on the projected operating profile of the unit. The owner will follow this program as it fits actual operations.

- **Turbine Design** - Good turbine design maximizes thermal efficiency. Combustion turbines operate at high temperatures. Heat radiated by the hot turbine components is lost to the surrounding atmosphere. To minimize this heat loss, turbines can be wrapped with insulating blankets so that more of the heat is retained in the hot gases for recovery of useful energy.

- **Instrumentation and Controls** - Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Today's F-Class turbines, like those being considered for this project, come from the manufacturer with a digital control package included. These systems control turbine operation, including fuel and air flow, to optimize combustion for control of criteria pollutant emissions (NO_X and CO) in addition to maintaining high operating efficiency to minimize fuel usage over the full range of operating conditions and loads.

- **Waste Heat Recovery** - As previously discussed, in a combined cycle configuration, a HRSG is used to recover what would otherwise be waste heat lost to the atmosphere in the hot turbine exhaust. Use of heat recovery from the turbine exhaust to produce steam to power a steam turbine which generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines used for electric power generation. The overall efficiency can be increased from about 30% for a simple cycle (no heat recovery) unit to about 50% for a combined cycle unit.

- **HRSG Design** - Efficient design of the HRSG improves overall thermal efficiency. This includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (IMO) for thermal efficiency; use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to HRSG surfaces and steam and water lines to minimize heat loss from radiation.

- **Minimizing Fouling of Heat Exchanger Surfaces** - Fouling of interior and exterior surfaces of the heat exchanger tubes hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance, including cleaning the tube surfaces as needed during scheduled equipment outages.

- **Fuel Heating** - Thermal efficiency of the turbine can be increased by pre-heating the fuel prior to combustion. This is usually accomplished by heat exchange with hot water from the HRSG.

- **Multiple Trains** - Combustion turbine efficiency is highest at full design load. As power demand drops, power production must be cut back. This may be accomplished by reducing duct burner firing to reduce power output of the steam turbine, reducing turbine output, and/or shutting down the unit completely. Use of multiple turbine/HRSG trains allows one or more train to be shut down while maintaining the remaining unit(s) at or near full load where maximum efficiency is achieved rather than operating a single unit at lower less efficient loads. The proposed unit in combination with the existing combined cycle unit will provide this flexibility.

- **CO_2 Capture and Sequestration (CCS)** - Capture and compression, transport, and geologic storage of the CO_2 is a post-combustion technology that is not considered commercially viable at this time for natural gas combustion sources. However, based on requests by EPA Region 6 for other GHG permit applications, CCS is evaluated further in this analysis.

- **Use of Low Carbon Fuel (other than natural gas)** - Natural gas is the lowest carbon fossil fuel that exists. Fuel gases, that contain significant amounts of hydrogen and which produce no CO_2 when burned, can be burned in turbines and duct burners if available. Use of fuel gas is an effective means of reducing GHG emissions in such situations.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 with the exception of CCS are considered "technically" feasible for the proposed turbine. Victoria successfully uses many of these efficiency and control measures on the existing combined cycle facility; thus, they are considered viable for the new proposed facility as well.

CCS is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities at the current time. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

> *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."*

A CCS project that EPA Region 6 has requested be addressed in GHG BACT analyses is the Indiana Gasification Project. This project differs from the Victoria VIC10 Project in several significant ways. The Indiana project will gasify coal, with the primary product being substitute natural gas (SNG), or methane. When coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. A series of reactions are then used to convert the CO and H_2 to methane. To meet pipeline specifications, the CO_2 must be removed from the SNG, which produces a relatively pure CO_2 stream that is inherently ready for sequestration. Combustion of natural gas in the proposed facilities produces an exhaust stream that is less than 5% CO_2, which is far from pure CO_2. Thus, while the Indiana Gasification Project will produce a CO_2 byproduct that is amenable to sequestration or use in enhanced oil recovery without significant further processing, the Victoria turbine will not. Separation (purification) of the CO_2 from the turbine combustion exhaust streams requires additional costly steps not otherwise necessary to the process. In addition, the viability of the Indiana Gasification Project is highly dependent on a 30-year contract requiring the State of Indiana to purchase the SNG produced and federal loan guarantees should the plant fail. In contrast, the proposed Victoria project relies on market conditions for viability and is not guaranteed by the government. Additionally, the Indiana project would produce SNG that has essentially the same CO_2 potential as the natural gas that will be burned in the proposed Victoria facilities. As such, the captured CO_2 equates only to the incremental increase from coal combustion compared to natural gas combustion. If, for example, the proposed unit were to burn SNG produced by the Indiana project, the CO_2e emissions would be virtually the same as proposed in this permit application.

The CO_2 stream included in this permit application is similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example, which are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1. The inference from the above citation is that for other types of facilities, CCS does not need to be listed as an available option in Step 1. However, to satisfy EPA Region 6 requests to address CCS in other BACT analyses, Victoria has assumed that CCS is a viable control option in the remainder of this BACT analysis.

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu that is about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes that typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Process fuel gas is also not an available fuel option for Victoria. Table C-1 in 40 CFR Part 98 Subpart C contains CO_2 emission factors for a variety of fuels. Coke oven gas, with a CO_2 factor of 46.85 kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas (53.02 kg/MMBtu). This fuel, however, is not an available fuel for the proposed project. Use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by up to 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most electric generating facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen is not produced at the Victoria Power Station and is not an available fuel for the proposed turbine and duct burners. Natural gas is the lowest carbon fuel available for use in the proposed facility; thus, use of low carbon fuel other than natural gas was eliminated due to lack of availability for the proposed facility.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies that were considered for controlling GHG emissions from the proposed turbine and duct burners in order of most effective to least effective include:

- CO_2 capture and storage;
- Waste heat recovery;
- Instrumentation and control system;
- Turbine design;
- HRSG design;
- Minimizing fouling of turbine/HRSG;
- Fuel pre-heating;
- Multiple turbine/HRSG trains; and
- Periodic maintenance and tune-ups.

CO_2 capture and storage is capable of achieving 90% reduction of CO_2 emissions in certain applications and thus is considered to be the most effective control method, when available.

Exhaust waste heat recovery can take several forms, and use of an HRSG with a steam turbine can increase thermal efficiency from around 30% for a simple cycle unit to about 50%, which is equivalent to about a 40% reduction in CO_2e emissions.

An instrumentation and control package to continuously monitor the turbine/HRSG equipment ensures the turbine is operating in the most efficient manner. Instrumentation and controls include:

- Fuel gas flow and usage;

- Exhaust gas temperature monitoring;
- Pressure monitoring around the turbine package;
- Temperature monitoring around the turbine package;
- Vibration monitoring;
- Air/fuel ratio monitoring;
- HRSG Unit temperature and pressure monitoring; and
- Part 75 certified CEMS and related QA/QC procedures to accurately represent emission rates.

At the existing Victoria facilities, periodic maintenance and tune-ups are performed according to the manufacturer's recommended program for actual operations. These programs consist of thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by the turbine vendor.

The effectiveness of instrumentation and control, maintenance and tune-ups, and the remaining efficiency improvement options cannot be quantitatively estimated, but are each generally in the <1% to 3% range, but any attempt to rank them in order of effectiveness would not be meaningful.

6.1.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

A brief evaluation of each technically feasible combustion turbine control option follows.

Carbon Capture and Sequestration (CCS)

The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed turbine, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effective analysis was performed for this option. The results of the analysis, presented in Table 6-1 and Table 6-2, show that the cost of CCS for the project would be approximately \$106 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about \$102,500,000 per year the proposed turbine/HRSG. The estimated total capital cost of the proposed project is \$200,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $19,000,000 for the project alone (the cost calculation is included and explained in Table 6-1). Thus, the annualized cost of CCS would be over five times the cost of the project without CCS. An additional cost of this magnitude would make the project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

There are additional negative impacts associated with use of CCS. The additional process equipment required to separate, cool, and compress the CO_2 would require significant additional power and energy expenditures. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, and/or increase the parasitic load on the proposed facilities which significantly reduces the net heat rate (efficiency) of the plant. Significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur per MW of net electricity produced.

Based on the excessive cost effectiveness in $/ton of GHG emissions controlled, the inability of the project to bear the high cost, and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project.

Instrumentation and Controls

Instrumentation and controls that can be applied to the combustion turbine/HRSG are identified in Section 6.1.3 and are considered an effective means of control for the proposed turbine configuration.

Waste Heat Recovery

Heat recovery systems consisting of a HRSG with steam turbine and other practices and design features identified in Section 6.1.1, that are designed to recover and utilize the waste heat in the turbine/HRSG train, are capable of effectively reducing GHG emissions per MW of power generated, by about 40% compared to a combustion turbine alone that exhausts to the atmosphere without any form of exhaust heat recovery.

Periodic Maintenance and Tune-ups

Periodic maintenance and tune-ups of the turbine include:

- Preventive maintenance check of fuel gas flow meters as required by 40 CFR Part 75, Appendix D, Section 2.1.6 (Quality Assurance),

- Cleaning of combustors on an as-needed basis, and

- Implementation of manufacturer's recommended inspection and maintenance program.

These and the remaining options listed below ensure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement.

- Turbine design;
- HRSG design;
- Minimizing fouling of turbine/HRSG;
- Fuel pre-heating; and
- Multiple turbine/HRSG trains.

6.1.5 Step 5 – Selection of BACT

As previously stated, applicable combustion turbine/HRSG design, waste heat recovery, plant design, and maintenance and tune-up options that increase overall efficiency by reducing the net plant heat rate are currently utilized on the existing turbine at the Victoria Power Station as they are good business practices and effective means of minimizing all air pollutants in addition to minimizing GHG emissions per MW of power generated. The following BACT practices are proposed for the new turbine/HRSG:

- Install a second turbine/HRSG train to allow shutdown of one unit during periods of low demand to minimize operation at less efficient reduced loads;

- Determine CO_2e emissions from the turbine/duct burners based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance;

- Good turbine design to maximize efficiency;

- Install and operate an efficiently designed HRSG and steam turbine;

- Design HRSG to recover heat from exhaust and blowdown for pre-heating of fuel and boiler feedwater;

- Install instrumentation and control package including:
  - Fuel gas flow and usage;
  - Exhaust gas temperature monitoring;
  - Pressure monitoring around the turbine package;
  - Temperature monitoring around the turbine package;
  - Vibration monitoring;
  - Air/fuel ratio monitoring; and
  - HRSG temperature and pressure monitoring.

- Implement vendor's recommended comprehensive inspection and maintenance program for the turbine;
- Clean turbine combustors and HRSG heat transfer surfaces as needed;
- Calibrate and perform preventive maintenance on the fuel flow meters as required by 40 CFR Part 75, Appendix D, Section 2.1.6 (Quality Assurance); and
- Maintain a minimum unfired efficiency standard of 7,679 Btu/kwh (HHV), baseload corrected to guaranteed conditions, expressed on a 12-month rolling average basis for the proposed turbine/HRSG.

Determination of Proposed Efficiency Standards

As previously stated, an RBLC database search did not yield any useful information for either identifying control technologies or establishing BACT performance limits for GHG emissions from turbines/HRSGs. However, EPA Region 6 has issued one GHG PSD permit for a similar combined cycle facility to LCRA (Thomas Ferguson Plant) in November 2011, and is currently reviewing two additional permit applications for similar Calpine facilities (Channel Energy Center and Deer Park Energy Center).

A Btu/kwh performance standard was proposed or established for each of these projects, all of which are located in Texas. Btu/kwh performance standards for three additional similar facilities permitted elsewhere in the United States were also identified. Table 6-3 presents a comparison of the performance standards for these facilities, that range from 7,605 Btu/kwh to 7,730 Btu/kwh, with those proposed for the Victoria Power Station VIC10 turbine/HRSG at 7,753 Btu/kwh, unfired baseload corrected to guaranteed conditions. All heat rates are based on HHV and the net plant power output in combined cycle mode.

The proposed heat rate limits use the design heat rate with the following margins added:

- 3.3% added for variations between as built and design conditions, including periods of operation at part load conditions,
- 6.0% for efficiency loss due to equipment degradation, and
- 3.0% for variations in operation of ancillary plant facilities.

These margins are the margins that were used by Calpine in the recently submitted GHG permit applications for their facilities that are included in Table 6-3. Victoria has evaluated these margins and agrees that they are realistic adjustments for the VIC10 facilities and is therefore using the same margins.

6.2 Natural Gas Pipeline Fugitives

Small amounts of methane emissions may occur from leaking natural gas piping components (process fugitives) associated with the proposed project. The methane emissions from natural gas pipeline fugitives have been conservatively estimated to be approximately 373 tpy as CO_2e. This is a negligible (~0.03%) contribution to the total GHG emissions from the project; however, for completeness, they are addressed in this BACT analysis.

6.2.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that may occur from process fugitives is clearly not cost effective due to the already insignificant level of emissions. However, a cost effectiveness analysis for a basic LDAR program to control process fugitive CH_4 emissions is presented in Table 6-4 to demonstrate this point. The analysis shows that even the least stringent LDAR program (TCEQ's 28M program) would cost $64/ton of CO_2e controlled. This cost is considered excessive for GHGs; therefore, it was rejected from further consideration.

6.2.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective and would result in no significant reduction in overall project GHG emissions regardless of cost. Based on these considerations, BACT is determined to be normal plant maintenance practices as needed to for safety and reliability purposes.

6.3 SF_6 Emissions from Electrical Equipment Insulation Leaks

Emissions of sulfur hexafluoride (SF_6) due to leaks from the insulation used in new circuit breakers are estimated to be about 0.11 lb/yr of actual mass emissions and less than 1.5 tpy of CO_2e. These emissions are negligible, and consideration of emissions controls for BACT purposes is not warranted. However, for completeness, they have been included in the BACT analysis. There are two methods for reducing or eliminating SF_6 emissions: 1) replace SF_6 with another insulation material, and 2) design the insulation systems to minimize SF_6 leaks.

SF_6 is a proven material for the proposed application and is considered to be a superior insulating material to alternatives currently available. Because even complete elimination of the emissions would result in no quantifiable benefit with respect to global warming potential, replacing it with an inferior alternative is not considered to be a prudent option and was eliminated from further consideration.

Modern high voltage circuit breakers are designed with totally enclosed insulation systems that result in minimal SF_6 leak potential. Alarm systems that can detect when a portion of the SF_6 has been lost from the system are available to identify leaks for repair before further losses occur. Although such systems would not necessarily be considered cost effective when expressed in traditional BACT $/ton of emissions avoided terms, their cost relative to the project cost is not prohibitive.

Victoria proposes to use circuit breakers with totally enclosed insulation systems equipped with a temperature compensated density monitor that alarms, and if pressure drops sufficiently, blocks the close or open of the circuit breaker.

Table 6-1. Cost Analysis for Post-Combustion CCS for CT/HRSG

CCS System Component	Cost of Control		Tons of CO_2 Controlled per Year (2)	Total Annualized Cost
	$/tonne (1)	S/ton		
CO_2 Capture and Compression Facilities	$114	$103	964,721	$99,770,546
CO_2 Transport Facilities (Table 6-2)		$2.26	964,721	$2,180,925
CO_2 Storage Facilities	$0.560	$0.51	964,721	$490,101
Total CCS System Cost		$106	964,721	$102,441,572

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor (3)	Annualized Capital Cost
Cost of Proposed Units w/o CCS	$200,000,000	0.0944	$18,878,585

Notes:

(1) Costs from the 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.

(2) Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from the VIC10 turbine and duct burner.

(3) Capital recovery factor is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time. Using an interest rate, i, and a number of annuity received, n, the capital recovery factor is:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

i = 7%

n = 20

Table 6-2 Pipeline Construction Cost Estimate

Description	Cost	Basis
Capital Cost:		
AGI Pipeline - 24" Diameter (1)	$17,000,000	10-mile pipeline 24-inch diameter (assumed "best case" distance to nearest storage cavern). DOE/NETL calculation method.
Capital Recovery Factor (2)	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$1,604,680**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$489,925	1000 hp (1hp = 745.7 w) electric compressor and $0.075/kwh electricity cost
O&M Cost, $/year (3)	$86,320	$8,632 $/mile/yr = O&M Cost, as published on DOE/NETL Quality Guidelines for Energy System Studies "Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, March 2010.
Total Annual Operating Cost ($/yr)	**$576,245**	
Total Cost:		
Total Annual Cost ($/yr)	$2,180,925	Annualized Capital Cost ($/yr) plus Annual Operating Cost ($/yr)
GHG Emissions Controlled (tpy)	964,721	From GHG Calculations in Appendix A
Cost Effectiveness ($/ton)	$2.26	Total Annual Cost ($/yr) divided by the GHG Emissions Controlled (ton/yr)

(1) Pipeline cost equations as published DOE/NETL Quality Guidelines for Energy System Studies "Estimating Carbon Dioxide Transport and Storage Costs", National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2010/1447, March 2010.

Component	Cost	Pipeline Cost Equation (Table 2 DOE/NETL-2010/1447)
Materials	$4,390,095	Materials = $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$8,064,863	Labor = $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$3,456,190	Misc. = $150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	$571,669	Right-of-Way = $48,037 + $1.20 x L x (577 x D + 29,788)

(2) Capital recovery factor is the ratio of a constant annuity to the present value of receiving that annuity for a given length of time. Using an interest rate, i, and a number of annuity received, n, the capital recovery factor is:

$$CRF = \frac{i * (1+i)^n}{(1+i)^n - 1}$$

i = 7%

n = 20

(3) Capital Cost for Construction of CO_2 Pipeline to Nearest Storage Cavern:

Length in miles (L): 10

Diameter in inches (D): 24

Several candidate storage reservoirs exist within 10 to 50 miles of the proposed project; however, none of these have been confirmed to be viable for large scale CO_2 storage at this time. However, it was assumed for this analysis that a suitable storage reservoir would be available within 10 miles.

Table 6-3 Comparision of Proposed Efficiency Standards with Other Facilities

Project	Performance Standard (Btu/kwh, HHV)	Comments
Proposed Victoria VIC10	7,753	Combined Cylce with duct burners, GE 7FA.04 turbines
LCRA Thomas Ferguson	7,720	Combined Cylce w/o duct burners, GE 7FA turbines
Palmdale Hybrid Power Project	7,319*	Combined Cylce with duct burners, GE 7FA turbines, integrated with solar-thermal plant
Cricket Valley Energy Center	7,605	Combined Cylce w/o duct burners, GE 7FA turbines
Pioneer Valley Energy Center	~7,525, HHV (6,840, LHV)	Combined Cylce, turbine model unknown
Proposed Calpine Channel Energy Center	7,730	Combined Cylce with duct burners, Siemens 501F turbine
Proposed Calpine Deer Park Energy Cener	7,730	Combined Cycle with duct burners, Siemens 501F turbine

* The Palmdale Hybrid Power Project is integrated with a solar energy plant that contributes thermal energy to the steam generator to produce part of the electric power. The heat rate limit is a site-wide heat rate that reflects the contribution from the solar energy collectors and thus cannot be compared directly to the heat rate limits of the other plants

Table 6-4 Cost Analysis for Natural Gas Fugitives LDAR Program

Monitoring Cost:	$2.50	per component per quarter
Number of Valves:	140	monitored
Number of Flanges:	350	not monitored
Number of PRVs:	10	monitored
Number of Pumps:	0	monitored
Number of Comps:	0	monitored
Total Number Monitored:	150	monitored
Total Cost of Monitoring:	$1,500	per year
Number of Repairs:	72	per year (12% of monitored components per quarter)
Cost of Repairs:	$12,240	per year @ $200 per component (85% of leaking components; remaining 15% only require minor repair)
Cost to re-monitor repairs:	$180	per year
Total Cost of LDAR:	$13,920	per year (montoring + repair + re-monitor)
Emission Reduction:	10.36	tpy of methane (based on 28M reduction credits)
Emission Reduction:	217.66	tpy of CO_2e
Cost Effectiveness:	$1,343	per ton of CH_4
Cost Effectiveness:	**$64**	per ton of CO_2e

Appendix A

GHG Federal New Source Review Applicability

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	TBD	Application Submittal Date:	2/14/2013
Company:	Victoria WLE LP		
RN:	100214980	Facility Location:	1205 Bottom Street, Victoria, TX 77901
City:	Victoria WLE LP	County:	Victoria
Permit Unit I.D.:	VIC10	Permit Name:	Victoria Power Station
Permit Activity:	☒ New Source	☐ Modification	

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**							
	Ozone		**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	Other[1]
	VOC	**NO_x**						**CO_2e**
Nonattainment?								No
PSD?								Yes
Existing site PTE (tpy)?								1,059,590
Proposed project emission increases (tpy from 2F[2])								1,845,282
Is the existing site a major source?								Yes
If not, is the project a major source by itself?								N/A
If site is major source, is project increase significant?								Yes
If netting required, estimated start of construction:	June 1, 2014							
5 years prior to start of construction contemporaneous	June 1, 2009							
Estimated start of operation period	June 1, 2015							
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								1,845,282
Major NSR Applicable?								Yes

[signature]	Asset Manager	2/13/2013
Signature	*Title*	*Date*

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emissions, increases only.

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

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]	CO_2e	Permit:	TBD
Baseline Period:	January 1, 2010	to	December 31, 2011

	Affected or Modified Facilities[2] FIN	EPN	Permit No.	Actual Emissions[3]	A Baseline Emissions[4]	B Proposed Emissions[5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
1	VIC10	VIC10	TBD		0.00	1,071,912		1,071,912		1,071,912
2	VIC10-FUG-NGAS	VIC10-FUG-NGAS	TBD		0.00	373.4		373.4		373.4
3	VIC10-INS-SF6	VIC10-INS-SF6	TBD		0.00	1.3		1.3		1.3
4	VIC7	VIC7	80878	286,595.21	286,595.21	1,059,590		772,994		772,994
5										
6										
7										
8										
9										
Page Subtotal[9]										1,845,282
Project Total										1,845,282

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

TCEQ

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Victoria WLE LP	
Permit Application Number: TBD	**Criteria Pollutant:** CO_2e

	Project Date[2]	Facility at Which Emission Change Occurred[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period (years)	A Proposed Emissions (tons/year)[4]	B Baseline Emissions (tons/year)[5]	Difference (A-B)[6]	Creditable Decrease or Increase[7]
1	TBD	VIC10	VIC10	TBD	Unit 10 CT/HRSG	NA	1,071,912	0.00	1,071,912	1,071,912
2	TBD	VIC10-FUG-NGAS	VIC10-FUG-NGAS	TBD	Unit 10 Natural Gas Fugitive Emissions	NA	373.4	0.0	373.4	373.4
3	TBD	VIC10-INS-SF6	VIC10-INS-SF6	TBD	Unit 10 Circuit Breaker Insulation SF6 Fugitives	NA	1.3	0.0	1.3	1.3
4	TBD	VIC7	VIC7	80878	Inlet Chiller Addition	2010-2011	1,059,590	286,595	772,994	772,994
5										
6										
7										
8										
9										
10										
						Page Subtotal[8]	2,131,877	286,595.21	1,845,282	1,845,282
						Summary of Contemporaneous Changes Total	2,131,877	286,595.21	1,845,282	1,845,282

[1] Individual Table 3F's should be used to summarize the project emission increase and net emission increase for each criteria pollutan

[2] The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed

[3] Emission Point No. as designated in NSR Permit or Emissions Inventory

[4] All records and calculations for these values must be available upon request

[5] All records and calculations for these values must be available upon request

[6] Proposed (column A) - Baseline (column B)

[7] If portion of the decrease not creditable, enter creditable amount

[8] Sum all values for this page.

Appendix B

Emission Rate Calculations

B-1 Combustion Turbine/Duct Burner Emissions Calculations - Unit 10 (VIC10)

EPN:	VIC10

Turbine:	GE 7FA

Specifications

Parameter		Value	Unit
Fuel Type : Natural Gas			
		1,024.3	Btu/scf
Annual Average Firing Rate:	Turbine	1,816.0	mmBtu/hr (HHV)
	Duct Burners	482.57	mmBtu/hr (HHV)
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 75 App G	118.9	lb/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbine	8,760	hr/yr
	Duct Burners	4,375	hr/yr
Note: All mmBtu values are HHV			

Emission Rates

Pollutant	tpy	GWP* Factor	CO_2e tpy
CO2	1,070,879	1	1,070,879
CH4	20	21	417
N20	2	310	616
Total CO2e	NA	NA	1,071,912

* Table A -1 to Subpart A of Part 98--Global Warming Potentials

Sample Calculations:

CO2 emission factor calculated from constants in Section 2.3 of Appendix G to 40 CFR Part 75 as follows:

CO2 (lb/mmBtu) = 1040 scf/mmbtu x 1 mole/385 scf x 44 lb CO2/mole = 118.9 lb/mmBtu

CO2 = (1,816.0 mmBtu/hr * 8,760 hr/yr) + 482.57 mmBtu/hr * 4,375 hr/yr) * 118.9 lb/mmBtu * 1ton/2000lb = 1,070,879 tpy

CH4 = (1,816.0 mmBtu/hr * 8,760 hr/yr) + 482.57 mmBtu/hr * 4,375 hr/yr) * 0.001 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb = 20 tpy

N2O = (1,816.0 mmBtu/hr * 8,760 hr/yr) + 482.57 mmBtu/hr * 4,375 hr/yr) * 0.000 kg/mmBtu * 1000g/kg * 1lb/453.6g * 1ton/2000lb = 2 tpy

CO2e = 1,070,879 tpy * 1 + 20 tpy * 21 + 2 tpy * 310 = 1,071,912 tpy

Fugitive Natural Gas (VIC10-FUG-NGAS)

Component Type	Stream Type	Emission Factor SOCMI without Ethylene (lb/hr/component)	Number of Components	Control Efficiency	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Valves	Gas/Vapor	0.0089	140	0%	1.25	5.46
	Light Liquid	0.0035	-	0%	-	-
	Heavy Liquid	0.0007	-	0%	-	-
Pumps	Light Liquid	0.0386	-	0%	-	-
	Heavy Liquid	0.0161	-	0%	-	-
Flanges	Gas/Vapor	0.0029	350	0%	1.02	4.45
	Light Liquid	0.0005	-	0%	-	-
	Heavy Liquid	0.0001	-	0%	-	-
Compressors	Gas/Vapor	0.5027	-	0%	-	-
Relief Valves	Gas/Vapor	0.2293	10	0%	2.29	10.04
Open Ends	-	0.0040	-	0%	-	-
Sample Con.	-	0.0330	-	0%	-	-
Other	Gas/Vapor	-	-	0%	-	-
	Lt/Hvy Liquid	-	-	0%	-	-
Process Drains	-	0.0700	-	0%	-	-
		Total	**500**		**4.55**	**19.95**

Normalized wt% Methane	**89.15%**
CH4 Emission Rate	**17.78 tpy**
GH4 Global Warming Potential*	**21**
CO2e	**373 tpy**

* Table A-1 to Subpart A of Part 98 - Global Warming Potentials

B-3 SF6 Emission Calculations for Electrical Equipment Insulation Leaks

EPN: VIC10-INS-SF6

Emissions of from leaks of SF6 gas used to insulate circuit breakers used in proposed plant.

Breaker Type (1)	HECS-80S
Operating Mechanism (1)	HMB-4.5
SF6 Gas Hold by GCB (1)	22.53 lb
Annual Leak Rate (2):	0.5%
Annual Emission Rate (3):	0.11 lb/yr
SF_6 Global Warming Potential Factor (4)	23,900
CO_2e (5)	**1.35 tpy**

Notes:

(1) Based on Circuit Breaker Vendor's Specifications

(2) IEC standard for new equipment leakage, as published on "SF6 Leak Rates from high Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas emissions Sources"

(3) Annual Emission Rate = 22.53 lb * 0.5% * 1 ton/2000 lb = 5.63E-05 tpy

(4) Table A-1 to Subpart A of Part 98 - Global Warming Potentials

(5) CO2e = 11,265.00E-05 tpy * 23,900 = 2,692.3 tpy