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May 3, 2007

Mr. Gerardo Rios
Chief, Permits Office (AIR 3)
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105

RE: Victorville 2 Hybrid Power Project (VV2) Application for PSD Permit and Request for Informal Endangered Species Act Consultation

Dear Mr. Rios:

As discussed with you and Ed Pike on July 18, 2006, and again with Mr. Pike recently, Inland Energy, Inc., on the behalf of the City of Victorville, is submitting an application for a Prevention of Significant Deterioration (PSD) permit for the VV2 Project. The VV2 Project is a hybrid power plant consisting of combined-cycle power plant integrated with 50 MW of solar arrays for a combined nominal output of 570 MW. Enclosed please find two copies of the PSD Application.

As discussed at our meeting last year, the City and Inland Energy understand that the U.S. Environmental Protection Agency (EPA) will be initiating consultation with the U.S. Fish and Wildlife Service, pursuant to Section 7 of the Endangered Species Act of 1973, as amended, regarding potential impacts to listed species resulting from EPA's issuance of a PSD permit for the VV2 Project. We have enclosed two copies of a Draft Biological Assessment (BA) for the VV2 Project to assist you with that consultation.

We also have included CD's with electronic copies of the PSD Application, modeling files and the Draft Biological Assessment. Please note that the Class II and Class I modeling protocols for the VV2 Project were submitted to the EPA on January 17, 2007. At your request, ENSR also submitted a copy of the Class I modeling protocol to the National Park Service (NPS) and the U.S. Forest Service Federal Land Managers (FLMs) on January 31, 2007. The NPS indicated that, based on the information in the protocol, they do not expect significant impacts on Joshua Tree National Park, and hence would not provide comments on the protocol. A copy of the PSD Application (but not the Draft BA) also is being submitted to the FLMs, as requested.

An air quality impact analysis has been conducted to demonstrate that the VV2 Project will not cause or contribute to violations of the National Ambient Air Quality Standards (NAAQS) during routine operations. The enclosed PSD Application includes the details of this impact analysis.

The City of Victorville submitted its Application of Certification (AFC) to the California Energy Commission (CEC) on February 28, 2007, and was deemed Data Adequate on April 11, 2007. The Application for a Determination of Compliance to the Mojave Desert Air Quality Management District (MDAQMD) has also been deemed complete. The contacts at these agencies for the VV2 Project include:

- Mr. John Kessler, Project Manager, CEC, 916-654-4679, Jkessler@energy.state.ca.us
- Mr. Alan De Salvio, Engineering Manager, MDAQMD, 760-245-1661, ext. 6726, adesalvio@mdaqmd.ca.gov

We request that EPA work with these other agencies to coordinate the timeline for permit approvals and requirements.

Please call Mr. Tom Barnett, Inland Energy (949) 856-2200 or me at (805) 388-3775 if you have any questions or need additional information. We appreciate your assistance with this matter.

Sincerely

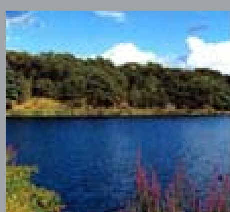
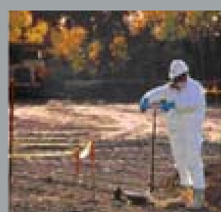
Sara J. Head

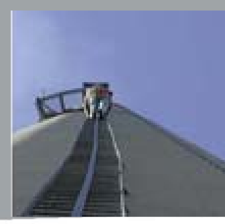
Sara J. Head
Vice President

Attachments: PSD Application (2)
Draft Biological Assessment (2)
Compact Disk (CD) with documents and modeling files

cc: Mr. Ed Pike, U.S. Environmental Protection Agency
Mr. Dee Morse, National Park Service (with PSD Application)
Mr. Mike McCorison, U.S. Forest Service (with PSD Application)
Mr. John Kessler, California Energy Commission
Mr. Alan De Salvio, Mojave Desert Air Quality Management District
Mr. Jon B. Roberts, City Manager, Victorville
Mr. Tom Barnett, Inland Energy, Inc.
Mr. Tony Penna, Inland Energy, Inc.
Mr. Mike Carroll, Latham & Watkins
Ms. Kim McCormick, Law Offices of Kim McCormick

Prepared for:
City of Victorville and Inland Energy, Inc.




Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project

ENSR Corporation
April 2007
Document No.: 10855-001-040a

Prepared for:
City of Victorville and Inland Energy, Inc.

Application for Prevention of Significant Deterioration Permit for Victorville 2 Hybrid Power Project

Prepared By

Reviewed By

ENSR Corporation
April 2007
Document No.: 10855-001-040a

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1.0 Introduction

1.1 Project Overview

The City of Victorville (City), a municipal corporation in the State of California, submits this Application for a Prevention of Significant Deterioration (PSD) Permit for the Victorville 2 Hybrid Power Project (referred to as the VV2 Project or Project). The Project will feature a 2 on 1 combined-cycle configuration with two GE 7FA gas turbines and one steam turbine producing a nominal electrical output of 570 megawatts (MW) along with a 250-acre solar thermal collection field, capable of producing 50 MW. The hybrid power plant will be owned by the City of Victorville, and the City has contracted with Inland Energy, Inc., to develop the Project. The combustion turbine trains will include heat recovery steam generators and will be fueled with natural gas only. In addition to the combustion turbines, the facility will contain ancillary combustion equipment including a natural gas-fired auxiliary boiler, a natural gas-fired heat transfer fluid (HTF) heater, a diesel-fired emergency generator, and a diesel-fired fire water pump engine. The facility will also include a wet mechanical draft cooling tower. Commercial operation is planned for the summer of 2010.

The VV2 Project is expected to supply power to the rapidly growing Southern California market while also supplying power locally to the City of Victorville's municipal power company, Victorville Municipal Utility Services (VMUS).

1.2 PSD Applicability

The VV2 Project will be located in an area that is designated federal non-attainment for respirable particulate matter (PM10) and ozone (O_3), and attainment or unclassified for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and fine particulate matter (PM2.5). Based on an estimate of preliminary facility air emissions, the Project will be a major source with respect to New Source Review (NSR) regulations, will trigger Prevention Significant Deterioration (PSD) review for NO_2 and CO, and will be subject to non-attainment new source review (NANSR) for PM10 and ozone precursors NO_x and volatile organic compounds (VOC). The Project will be a minor source of SO_x, lead, and other PSD pollutants. Table 1-1 provides a summary of the emissions in tons per year (tpy) and PSD applicability for this Project.

This application for a PSD permit is being submitted to the U.S. Environmental Protection Agency (EPA), which administers the PSD program in this area. The Mojave Desert Air Quality Management District (MDAQMD) manages the local NANSR program, and an application has also been submitted to the MDAQMD and the California Energy Commission (CEC). Although this area is attainment for PM2.5, the implementation rule for PM2.5 is not yet finalized. PSD therefore does not yet apply to this pollutant. However, the Application for Certification (AFC) submitted to the CEC does fully analyze the impacts from the VV2 Project on PM2.5, and the Project was shown to not cause or contribute to an exceedance of the National Ambient Air Quality Standards for PM2.5 (see 6.03 Air Quality.pdf under Applicant's Documents at http://www.energy.ca.gov/sitingcases/victorville2/documents/index.html). This AFC document includes a control technology review for PM10 emissions (the controls applicable to PM2.5 would be the same as those for PM10), as well as precursor emissions such as NO_2 and SO_2. The AFC also contains an alternatives analysis, including cooling technologies, in Section 5.

Table 1-1
PSD Applicability Thresholds For the VV2 Project

Pollutant	PSD Facility Applicability Level (tpy)	Facility Emissions (tpy)	PSD Applies
NO_x	100	111.9	Yes
SO_2	100	8.3	No
PM10 [a]	N/A	120.9	No
CO	100	257.3	Yes
VOC	N/A	34.6	No
N/A – Not Applicable as the pollutant is classified as nonattainment or as a nonattainment precursor pollutant.			
a. PM2-5 emissions conservatively assumed to be equal to PM10.			

1.3 Application Contacts

The following persons can be contracted for information regarding this application

Jon B. Roberts, City Manager, City of Victorville
14343 Civic Drive / PO Box 5001, Victorville, CA 92393
760-955-5000

Tom Barnett, Senior Vice President, Inland Energy, Inc.
South Tower, Suite 606, 3501 Jamboree Road, Newport Beach, CA 92660
949-856-2200, tbarnett@inlandenergy.com

Sara Head, Vice President, ENSR
1220 Avenida Acaso, Camarillo, CA 93012
805-388-3775, shead@ensr.aecom.com

1.4 Application Contents

Section 2 of this PSD application contains a description of the Project, including a description of the equipment that is proposed. Section 3 provides a regulatory analysis. An evaluation of the control technology requirements is provided in Section 4 and the emissions summaries are contained in Section 5. Section 6 describes the modeling analyses performed for both the Class II area in the vicinity of the project and the Class I areas within 100 kilometers (km). References are given in Section 7. Appendices contain additional information on the control technology listings, emissions calculations, and modeling files.

2.0 Proposed Project

2.1 Overview

The proposed VV2 Project consists of a hybrid of natural gas-fired combined-cycle generating equipment integrated with solar thermal generating equipment. The combined-cycle equipment will utilize two natural gas-fired combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). The solar thermal equipment will utilize arrays of parabolic collectors that heat a working fluid that is then used to generate steam. The combined-cycle equipment is integrated thermally with the solar equipment in that both utilize the single STG that is part of the VV2 Project.

The Project will have a nominal electrical output of 570 MW and commercial operation is planned for the summer of 2010. The solar thermal input will provide approximately 10 percent of the peak power generated by the plant during the most energy demanding time of the day.

The Project will employ several technologies and approaches to reduce air emissions. The combined-cycle units will use selective catalytic reduction (SCR) and oxidation catalyst equipment to control air emissions. The combustion turbines will also be equipped with GE's Rapid Start Process technology and the facility will include an auxiliary boiler to decrease emissions during startups. The cooling tower will have a high efficiency drift eliminator. The primary fuel for the facility will be pipeline quality natural gas.

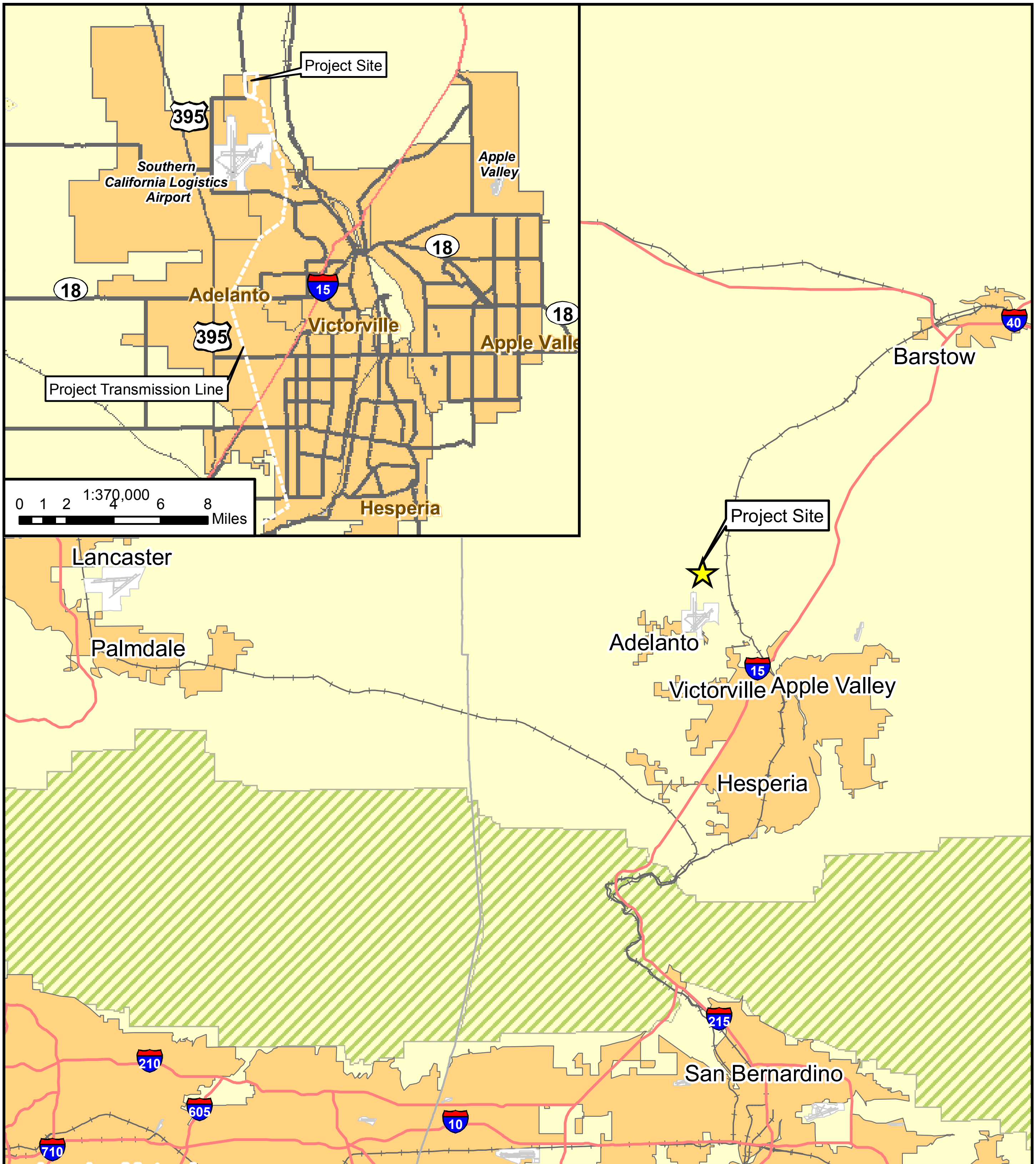
The Project will be fueled with natural gas delivered via an existing natural gas pipeline that supplies the High Desert Power Project (HDPP) located approximately three miles south of the VV2 Project site; this pipeline has sufficient capacity to serve both the VV2 Project and HDPP and is located adjacent to the western boundary of the Project site.

The proposed interconnection point for the VV2 Project with the SCE electrical transmission system is at SCE's existing Victor Substation, approximately 10 miles south-southwest of the Project site.

Reclaimed water for the VV2 Project cooling tower makeup and other industrial uses will be supplied from the nearby Victor Valley Wastewater Reclamation Authority (VVWRA) treatment plant via a new approximately 1.5-mile pipeline. Except for sanitary wastewater that will be disposed through a new approximately 1.25-mile pipeline to an existing sewer interceptor near the VVWRA plant, the Project will be a zero liquid discharge (ZLD) design. Brine (cooling water blowdown) from the Project will be processed to solid waste and disposed at an appropriately permitted offsite disposal facility. The Project's backup cooling water supply will be through a connection to an existing City of Victorville pipeline adjacent to the western boundary of the site that carries State Water Project water. This backup will be used only if there are extended outages in the reclaimed water supply system.

2.2 Location of Facilities

As shown on Figures 2-1 and 2-2, the VV2 Project site is located north of the Southern California Logistics Airport (SCLA), the former George Air Force Base, in the City of Victorville, San Bernardino County, California. The site lies approximately 3.5 miles east of U.S. Highway 395 and approximately 0.5 mile west of the Mojave River (see Figure 2-1). An aerial view of the Project Site with simulated Project facilities is shown in Figure 2-3.



Locus Map

Regional and Vicinity Map

Victorville 2 Hybrid Power Project

Legend

Urban Areas

National Forests

Freeway System

1:600,000

0 2.5 5 10 15 20 Miles

Inland Energy, Inc.

ENSR | AECOM

Figure 2-1

Date: April 2007

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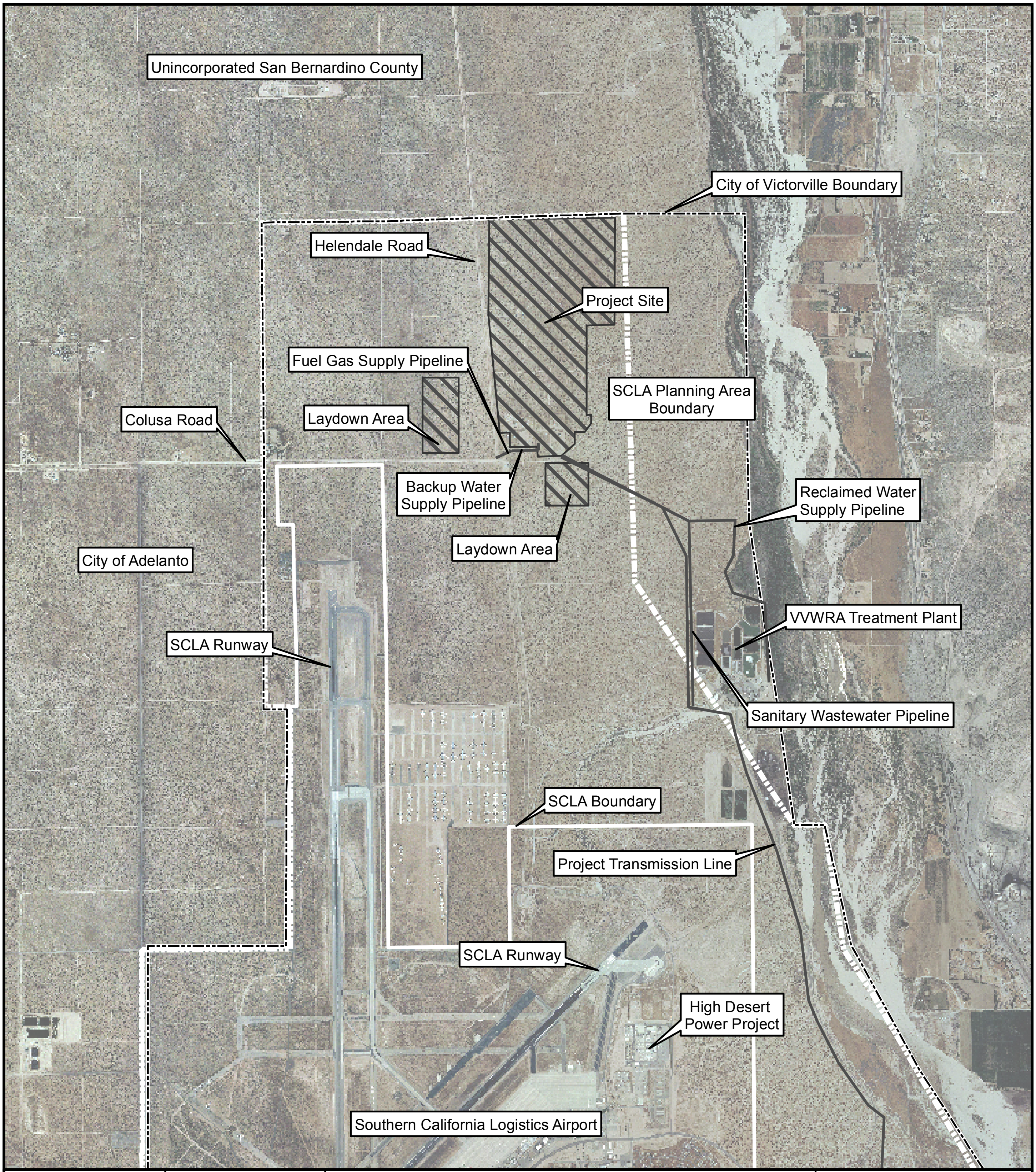
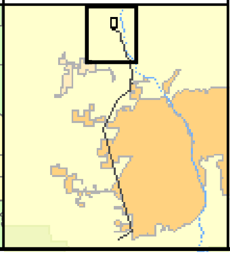


Locus Map

Index Map



Project Site and Surrounding Area

Victorville 2 Hybrid Power Project

Source: MapMart Aerial Imagery .61 Meter Resolution Circa 2004

Scale: 1:36,000

0 2,000 4,000 6,000 8,000 Feet

N S

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Figure: 2-2

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Figure 2-3 Aerial View of Project Site with Simulated Project Facilities

Figure 2-2 illustrates the location of the Project power plant site and two adjacent construction laydown areas, as well as the routes of the Project's reclaimed water supply, fuel gas supply, sanitary wastewater disposal, backup water supply, and natural gas pipelines and its transmission lines. The southwest corner of the site is located just north of the intersection of Colusa Road and Helendale Road, approximately one mile northeast of the end of the SCLA north-south runway. Roadway access to the Project site will be from the south along what currently is called Helendale Road. This section of Helendale Road is currently unpaved but will be improved (and renamed Perimeter Road) by the City of Victorville as part of infrastructure upgrades to support planned future development at SCLA and its adjoining planning area (which includes the VV2 Project site).

The legal description of the VV2 Project site is as follows: a portion of Section 2, Township 6 North, Range 5 West, (San Bernardino Base and Meridian), located within the northwest corner of the City of Victorville, California. A new parcel will be created that corresponds with the roughly 275-acre Project site. The power plant site is largely vacant land and consists of primarily five-acre parcels, which are either already under City control or are in the process of being acquired. The City of Victorville is currently acquiring approximately 375 acres for this and other projects, of which a 275-acre subset will be separated and used to construct the VV2 Project.

The existing condition of the Project site is mostly undisturbed land and is surrounded by vacant, undisturbed land. The site is largely flat, with elevations ranging from approximately 2,780 to 2,820 feet above mean sea level (amsl), although at the eastern perimeter of the site and further to the east, topography slopes down to the Mojave River.

2.3 Generating Facility Description

The following sections describe the VV2 Project site arrangement and the processes, systems, and equipment that constitute the proposed power plant. All Project facilities will be designed, constructed and operated in accordance with applicable laws, ordinances, regulations and standards.

2.3.1 Site Arrangement

Facility Diagrams are provided in Appendix A. The Site Plan shows the layout of Project facilities including:

- Plant site, including both the combined-cycle power block and the solar arrays
- Laydown areas
- Fuel gas supply
- Reclaimed water supply
- Sanitary wastewater disposal,
- Backup water supply pipelines, and
- First portion of the Project transmission line

The plot plan of the Project's combined-cycle power block includes the following major components of the Project:

- Two combustion turbine generators (CTGs), each with a heat recovery steam generator (HRSG),
- One steam turbine generator (STG),
- Approximately 250 acres of solar-thermal collectors with associated heat transfer equipment,
- One wet cooling tower,
- An Operations building that incorporates control, maintenance, and administrative functions, and

- A 230-kV switchyard.

An elevation drawing for the power block is also included in Appendix A.

2.3.2 Process Description

This section describes the power generation process and thermodynamic cycle employed by the VV2 Project. The power plant consists of:

- Two CTGs equipped with dry low NO_x combustors and evaporative inlet air coolers,
- Two HRSGs equipped with duct burners,
- One STG, and
- An approximately 250-acre solar thermal collection field with a solar steam boiler and associated auxiliary systems and equipment.

The CTGs and duct burners are fueled exclusively with natural gas. The duct burners enable the HRSGs to produce extra steam in order to obtain peaking output from the STG.

During periods when the solar collectors are in use (i.e., daytime when the sun is shining on the site), the solar field will provide heat directly to the HRSGs to produce more steam, which will allow the facility to reduce firing of the duct burners. This design feature enhances the Project's ability to respond to the energy markets by providing peak power during peak demand periods (e.g., hot summer afternoons) while consuming less natural gas fuel.

At full load, each CTG generates approximately 154 MW (gross) at average ambient conditions. Heat from the CTG exhausts is used in the HRSGs to generate steam and to reheat steam. With the CTGs at full load and the duct burners and solar field out-of-service, the HRSGs produce sufficient steam for operation of the STG at an output of 169 MW (gross) at average ambient conditions, which results in an overall plant gross output of approximately 477 MW (gross). With the CTGs at full load and the duct burners in-service, the HRSGs produce sufficient steam for operation of the STG at its peaking output of 267 MW (gross) at average ambient conditions, which results in an overall plant gross output of approximately 563 MW (net). At full load solar operation, the heat from the solar field can replace the equivalent of approximately 50 MW of duct firing, thereby improving the Project's overall heat rate and reducing air emissions.

Overall, annual availability of the VV2 facility is expected to be in the range of 90 to 95 percent. The plant's capacity factor will depend on the provisions of bilateral power sales contracts as well as market prices for electricity, ancillary services, and natural gas. The design of the power plant provides for operating flexibility (i.e., ability to rapidly start up, shut down, turn down, and provide peaking output), so that operations may be readily adapted to changing market conditions. Included in this flexibility is the ability of the plant to start up the combined-cycle system in slightly over one-half the industry standard for combined-cycle plants it the United States.

The "Rapid Start Process" (RSP) offered by General Electric Power Systems (GE), the supplier of the Project's combustion equipment, allows for faster starting of the gas turbines by mitigating the restrictions of former HRSG designs. Traditionally, the CTGs are brought to full load slowly to limit combined stresses in the high pressure steam drum of the HRSG due to the exhaust temperature of the CTGs. The new GE design eliminates this restriction by modifying the steam drum design. Additional equipment to support the

RSP includes an auxiliary boiler supplying a sealing steam header to allow startup of the steam turbine to follow shortly after the gas turbines.

The following provides a brief description of the combined-cycle equipment's thermodynamic cycle (a combination of the Brayton and Rankine cycles). Air flows through the inlet air filter, evaporative cooler, and associated inlet air ductwork of each CTG and is then compressed in the CTG compressor. Compressed air exiting the compressor flows to the CTG combustors. Natural gas fuel is then injected into the combustors and ignited. The hot combustion gases expand through the CTG's turbine to drive the entire CTG, including the compressor and the electric generator which share a common shaft with the turbine. The hot combustion gases exit the turbine and enter the HRSG dedicated to that CTG. Duct burners installed in each HRSG further heat the CTG exhausts at times when peaking output is desired.

In the HRSGs, heat from the CTG exhausts is transferred to water pumped into the HRSG pressure parts (economizers, evaporators, drums, etc.). The water is converted to superheated steam and is delivered to the STG at three pressures, high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures provides an increase in cycle efficiency. HP steam from the HRSG is admitted to the HP section of the STG, expands through the HP section to drive the STG, and exits the HP section as 'cold reheat' steam. The cold reheat steam is combined with IP steam from the HRSG and delivered to the HRSG reheater. 'Hot reheat' steam leaving the reheater is admitted to the IP section of the STG and expands through the IP and LP sections to further drive the STG. LP steam from the HRSG is admitted to the LP section of the STG and expands through the LP section to also further drive the STG.

Steam leaving the LP section of the STG enters a surface condenser, gives up its latent heat to circulating water, and is condensed to liquid. The circulating water flows through a wet cooling tower where the waste heat is rejected to the atmosphere and the circulating water is then pumped back to the surface condenser.

The cycle described above does not change with the addition of the solar hybrid concept. The solar field circulates a heat transfer fluid (HTF) from the solar boiler and heat exchangers to the solar field. Light from the sun reflects off the solar collector's parabolic troughs and is concentrated on the HTF, which flows in tubes at the focal point of the parabolic troughs. The concentrated sunlight heats the HTF and the heated HTF flows to the solar boiler. Steam from the solar boiler is then fed into the HRSG's high-pressure steam drum to add heat to the steam cycle. This addition reduces the need for duct burning to meet peak power demands.

The HTF planned for use is Therminol™ VP-1, a high temperature, low-pressure oil widely used in solar thermal and other heat transfer applications. The HTF is a low vapor-pressure fluid that allows the solar system to remain at low pressure, thereby enhancing safety by reducing the likelihood of leaks.

2.3.3 Energy Conversion Facilities Description

This section describes the major energy conversion components of the proposed VV2 Project including the CTGs, HRSGs, STG, and solar system.

2.3.3.1 Combustion Turbine-Generators (CTG)

Thermal energy is produced in each of the two CTGs through the combustion of natural gas, and the thermal energy is converted into mechanical energy by the CTG turbine that drives the CTG compressor and electric generator. The CTGs proposed for the VV2 Project employ ‘F’ technology and are supplied by GE Power Systems. Each CTG consists of a heavy duty, single shaft, combustion turbine-generator and associated auxiliary equipment. The CTGs are equipped with dry low NO_x combustors designed for natural gas. Procurement of the CTGs is based on functional performance criteria, including the following:

- Air emissions at the gas turbine exhaust shall not exceed specified levels.
- Noise emissions shall not exceed specified near-field and property line levels.
- Each CTG shall be capable of operation at 50 percent to 100 percent load while meeting specified air emissions performance criteria.
- Each CTG shall be capable of a specified number of startups per year.

The CTGs are equipped with accessories required to provide efficient, safe and reliable operation, including the following:

- Inlet air filters and on-line filter cleaning system,
- Evaporative inlet air coolers,
- On-line and off-line compressor wash system,
- Fire detection and protection system,
- Lubrication oil system including oil coolers and filters,
- Generator coolers,
- Starting system, auxiliary power system, and control system, and
- Metal acoustical enclosures designed for outdoor service.

2.3.3.2 Heat Recovery Steam Generators (HRSG) and Steam Cycle

In the combined-cycle configuration, each gas turbine will exhaust to a dedicated HRSG. Each of the two trains will consist of one CTG and one HRSG. Both CTG-HRSG trains will feed steam into a common STG (a standard 2-on-1 configuration).

Each HRSG is a horizontal, natural circulation type unit with three pressure levels of steam generation and reheat loop. High-pressure steam at 1,800 pounds per square inch gage (psig) and 1,050°F is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam is mixed with intermediate pressure steam and reintroduced into the HRSG through the reheat loop. The hot reheat steam flows to the intermediate-pressure section of the STG and then to the low-pressure section of the STG. Low-pressure steam from the HRSG also flows to the low-pressure section of the STG. The STG drives an electric generator to produce electricity.

In the proposed hybrid configuration with the solar thermal component integrated into the VV2 Project, additional HP steam is produced during daylight hours from heat collected via the solar array. The solar array heats a working fluid that is used to produce HP steam in a heat exchanger. This HP steam is re-introduced into the combined-cycle system via injection of the solar-generated saturated HP steam into the HP drum of the HRSG. This steam is then superheated in the HRSG superheaters along with the HP steam produced within the HRSG evaporator itself. The STG exhaust steam is condensed in the de-aerating surface condenser with water from a multi-cell wet cooling tower.

Make-up water to the cooling tower will be tertiary treated water from the VVWRA reclaimed water production system brought to the site by a new 1.5-mile pipeline. Blowdown from the cooling tower will be processed in the ZLD system.

GE "Rapid Start Process" (RSP). As noted earlier, the VV2 Project is designed with GE's RSP, which will allow the CTG to reach base load more quickly, reducing startup emissions (emission rates are higher during startup than during normal steady-state operations) and thereby facilitating Project compliance with air emission requirements. Table 2-1 shows the RSP startup rates and startup rates without the RSP. As shown in the table, the RSP reduces CTG startup rates most substantially (by more than 50 percent) during cold starts, with smaller reductions in startup time during warm and hot starts; the RSP does not affect STG startup times.

To facilitate the RSP approach, the HRSGs will be of a modified design. Typical HRSG designs limit the CTG start rate due to the exhaust temperature heating the steam drum too quickly. This limitation is caused by thermal stress limitations on the high-pressure steam drum due to the shell thickness. To avoid this limitation, a modified drum design will be used that allows for thinner wall thickness; this is achieved by elongating the steam drum and reducing its diameter, which allows the steam drum volume to remain relatively unchanged.

Table 2-1
Time (Minutes) to Full Load With and Without GE "Rapid Start Process"

Component	Cold	Warm	Hot
GT1 (Typical)	210	102	62
GT1 (RSP)	70	40	40
GT2 (Typical)	240	124	83
GT2 (RSP)	103	71	71
STG (Typical/RSP)	240	130	130

An alternative approach was considered to reduce combined-cycle system startup times. This alternative included a "once-through" boiler that controls feed water by rate control, which removes the high-pressure steam drum as the limiting component by eliminating it all together. However, the modified drum design described above provides equivalent rapid startup capability without the increased sensitivity to water purity and the need for additional purification equipment associated with the once-through boiler. The once-through boiler approach also removes the planned solar heat input location (high-pressure steam drum), which complicates the Project's hybrid approach (integrated combined-cycle and solar equipment).

2.3.3.3 Auxiliary Boiler

Another limiting factor for startup of combined-cycle equipment is the ability to draw a vacuum on the condenser allowing STG startup to commence. The VV2 Project will use an auxiliary boiler to facilitate rapid startup by providing STG sealing steam prior to CTG startup, thereby allowing the condenser vacuum to be established and the condenser be in a condition ready to accept steam as soon as it is needed. This also avoids the need to vent considerable steam to the atmosphere while waiting for condenser vacuum to be established following CTG start and the beginning of steam generation within the HRSG.

2.3.3.4 Steam Turbine-Generator (STG)

As described earlier, steam from the HRSGs is sent to the STG. The steam expands through the STG turbine blades to drive the steam turbine, which in turn drives the generator. The VV2 Project's STG is of the reheat type and is equipped with accessories required to provide efficient, safe, and reliable operation, including the following:

- Governor system,
- Steam admission system,
- Gland seal system,
- Lubrication oil system including oil coolers and filters,
- Generator coolers, and
- Metal acoustical enclosures designed for outdoor service.

2.3.3.5 Solar Thermal Field System Description

The collector field is made up of a large field of diurnal, single-axis-tracking parabolic trough solar collectors. The solar field is modular in nature and comprises many parallel rows of solar collectors, normally aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector (referred to as the Heat Collection Element (HCE) that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola.

The collectors track the sun from east to west during the diurnal cycle to ensure that the sun is continuously focused on the linear receiver. The heat transfer fluid (HTF) is heated up to approximately 740° F as it circulates through the receiver and returns to a series of heat exchangers where the fluid is used to generate high-pressure steam. At the VV2 Project, these heat exchangers are located in the combined-cycle power block (the area where the CTGs, HRSGs, and STG are located). To integrate the solar and combined-cycle Project components, the solar-generated high-pressure steam is then sent to the HP steam section of an on-site HRSG, and thereby contributes to the output of the Project's STG.

Parabolic trough solar technology is the most proven and lowest cost large-scale solar power technology available today, primarily because of the nine commercial-scale solar electric generating station (SEGS) facilities that are operating in the Mojave at Harper Lake, Kramer Junction, and Daggett. More than 2,000,000 m^2 of parabolic trough collector technology have been operating daily for 15+ years, and have accumulated over 175 "plant years" of operational experience. Although no new solar electric generating plants have been built since 1990, significant advancements in collector and plant design have been made possible by the efforts of the SEGS operators, the parabolic trough industry, and solar research laboratories around the world. These improvements include advancements in mirror durability in high winds, receiver efficiency, structural design, cost reduction and system control.

2.3.3.6 Emergency Generator

The emergency diesel generator will supply electrical power to the power plant critical services in the event of a total power outage of switchyard and the plant. The plant critical services will include battery chargers, turning gear, lubricating oil systems, DCS/PLC controls and critical lighting. The generator will be designed, tested, rated, assembled and installed in accordance with all the applicable standards. The equipment shall meet the requirements of NEC and all applicable codes and regulation.

The generator will be Standby rated at 700 kW, 875 KVA, 1,800 RPM, at 0.8 power factor, 480 VAC, 3 phase, 4 wire, 60 hertz, 480/277 VAC, wyes connected to a high resistance grounded system, including radiator fan and all parasitic loads. The diesel generator will have auto-sync capabilities.

The emergency diesel generator will be installed in a dedicated area in the combined-cycle area of the plant site and will include the following major components:

- Diesel Engine,
- Governor,
- Lubricating System,
- Fuel System,
- Generator,
- Exciter,
- Voltage Regulator,
- Remote Synchronizing Panel, including protective relaying and metering,
- Generator Mounted Control Panel,
- Cooling System,
- Fuel Piping and 24 hours Fuel Tank,
- Exhaust System,
- Starting System including Batteries and Batteries Charger, and
- Weather Protective Enclosure.

The plant critical or essential auxiliary electric loads will be served by the normal plant auxiliary power system at 480V or less except when the normal source of power is interrupted or in the case of complete power shutdown at the plant. The emergency generator power system and the critical equipment system will be designed and arranged so that, in the event of failure of the normal auxiliary power, the emergency diesel generator will be automatically connected within 10 seconds to the essential loads and the switching devices (time delay or non-automatic) that are supplying the critical/essential loads.

When the normal plant auxiliary power source is restored, and after a time delay, the automatic transfer switch will disconnect the emergency power source and connect the load to the normal power source. The emergency diesel generator will be periodically tested to confirm its mechanical, electrical and control equipment integrity. The emergency generator system will be synchronized with the normal auxiliary power system from time to time to test its total output power into the system.

2.3.4 Plant Auxiliary Systems and Process Descriptions

The following subsections describe the various plant auxiliary systems (fuel supply, water supply, water treatment, cooling systems, air emissions control, waste management, etc.) associated with the VV2 Project.

2.3.4.1 Fuel Supply and Use

The CTGs and duct burners are designed to burn natural gas. The fuel requirement for base load operation at average ambient conditions is approximately 69.1 MMscfd. The fuel requirement for peaking operation at 77°F/40%RH ambient conditions is approximately 87.5 MMscfd without solar and 78.3 MMscfd with full solar.

Natural gas for the duct burner systems branches off and is regulated to a lower pressure. Safety pressure relief valves are provided downstream of pressure regulation valves. The CTG systems include a natural gas preheater and flow modulation equipment; the duct burner systems also have flow modulation equipment. Table 2-2 shows the typical composition of the natural gas that will fuel the VV2 Project. Table 2-3 shows the maximum natural gas usage for each combustion unit.

Table 2-2
Typical Natural Gas Composition

Component	Molar %
Methane, CH_4	95.13
Ethane, C_2H_6	2.66
Propane, C_3H_8	0.35
Butane, C_4H_{10}	0.08
Pentane, C_5H_{12}	0.02
Hexane, C_6H_{14}	0.01
Carbon Dioxide, CO_2	0.72
Nitrogen, N_2	1.03
Total	**100.00**
Sulfur (grains per 100 scf)	0.20
Lower Heating Value (Btu/lb)	20,669
Natural Gas Ratio (HHV/LHV)	1.109

Table 2-3
Equipment Sizes and Maximum Natural Gas Usage (Per Unit)

Component	No. of Units	Maximum Heat Input (MMBtu/hr)[a]	Maximum Annual Usage (hours/year)	Maximum Fuel Usage (MMscf/year)
GE 7FA CTG	2	1,736.4	8,760	14,854
HRSG Duct Burner	2	424.3	8,760	3,630
Auxiliary Boiler	1	35	500	17.1
HTF Heater	1	40	1,000	39.1[b]

a. Higher Heating Value, based on 1,024 Btu/scf
b. Most of the HTF heater fuel usage will be in the months of Nov. through Feb.

2.3.4.2 Cooling Systems

The power plant includes two cooling systems; 1) the steam cycle heat rejection system (e.g., cooling tower) and, 2) the closed cooling water system (equipment cooling), each of which is discussed below.

Steam Cycle Heat Rejection System. The cooling system for heat rejection from the steam cycle consists of a surface condenser, circulating water system, and a wet cooling tower. The surface condenser receives exhaust steam from the LP section of the STG and condenses it to liquid for return to the HRSGs. The surface condenser is a shell-and-tube heat exchanger with wet, saturated steam condensing on the shell side and circulating water flowing through the tubes to provide cooling.

The shell side of the condenser is designed to operate under a vacuum. For example, during base load (unfired) operation at average ambient conditions (77°F/40 percent RH), the condenser is expected to operate at pressure of 1.80 in HgA. Under these conditions, the condenser duty is approximately 975 MMBtu/hr. The auxiliary cooling water system contributes 60 MMBtu/hr of that total duty. This heat is absorbed by the circulating water from the tower, which warms by approximately 17°F (27°F at peak load). The warmed circulating water exits the condenser and flows to the cooling tower.

The circulating water is distributed among multiple cells of the cooling tower, where it cascades downward through each cell and then collects in the cooling tower basin. The mechanical draft cooling tower employs electric motor-driven fans to move air through each cooling tower cell. The cascading circulating water is partially evaporated, and the evaporated water is dispersed to the atmosphere as part of the moist air leaving each cooling tower cell. As discussed in Sections 6.3, Air Quality and 6.15, Visual Resources, because of climatic conditions at the site, visible moisture plumes are expected to occur relatively infrequently and largely in winter months, and no need is expected for a plume-abated cooling tower.

The circulating water is cooled primarily through its partial evaporation and secondarily through heat transfer with the air. The cooled circulating water is pumped from the cooling tower basin back to the surface condenser.

Closed Cooling Water System. The closed cooling water system is filled with a coolant such as a mixture of glycol and water. This coolant is pumped in a closed loop for the purpose of cooling equipment including the CTG and STG lubrication oil coolers, the CTG and STG generator coolers, air compressor aftercoolers, steam cycle sample coolers, etc. The coolant picks up heat from the various equipment items being cooled and the coolant itself is then cooled by non-contact heat exchange with a branch of the circulating water system.

2.3.4.3 Air Emissions Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and duct burners are controlled by state-of-the-art systems. Emissions that are controlled with control equipment are NO_x, CO, VOC. Particulates (PM10 and PM2.5) and SO_2 are minimized by burning low-sulfur natural gas. Continuous emissions monitoring for NO_x and CO is performed to ensure that the control systems perform correctly and to provide compliance documentation. All emissions values stated in this application are based on parts per million by volume, dry basis (ppmvd) corrected to 15% oxygen (O_2). An evaluation of the control system selection is provided in Section 4 and a summary of emission rates from the proposed equipment is provided in Section 5. A brief description of planned air emissions control methods is provided in the following paragraphs.

Nitrogen Oxides Emissions Control. Stack emissions of NO_x will be controlled by use of dry low-NO_x (DLN) combustors in the CTGs followed by selective catalytic reduction (SCR) in the HRSGs. The DLN combustors control NO_x emissions at the CTG exhausts by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen at the flame front.

The SCR process uses aqueous ammonia (NH_4OH) as a reagent. Stack emissions of ammonia, referred to as ‘ammonia slip,’ could be up to 10 ppmvd. The SCR system includes a catalyst bed located within each HRSG, ammonia storage system, and ammonia injection system. The catalyst bed is located in a temperature zone of the HRSG where the catalyst is most effective over the range of loads at which the plant will operate. The ammonia injection grid is located upstream of the catalyst bed. The plant ammonia consumption rate is approximately 266 lb/hr at base load (77ºF/40% RH unfired) conditions and 571 lb/hr at maximum load (18ºF/60% RH fired). A 30,000-gallon aqueous ammonia storage tank located on the VV2 Project site provides sufficient capacity for more than 14 days of continuous operation.

Other Pollutant Emissions Control. Emissions of CO and VOC will be controlled with oxidation catalyst systems located within each HRSG. The oxidation catalyst will also reduce the emissions of hazardous air pollutants.

Fine particulate emissions are controlled by inlet air filtration and by the use of natural gas fuel, which contains essentially no particulate matter. Stack emissions of PM10 consist primarily of hydrocarbon particles formed during combustion. Sulfur dioxide emissions are controlled by the use of natural gas fuel, which contains only trace quantities of sulfur.

Continuous Emissions Monitoring System (CEMS). The Project’s CEMS will sample, analyze, and record NO_x, CO, and O_2 concentrations in the stack exhaust. The CEMS will generate a log of emissions data for compliance documentation and activate an alarm in the plant control room when stack emissions exceed specified limits.

2.4 Project Construction and Operating Schedule

2.4.1 Project Construction

The planned VV2 Project construction schedule is as follows:

- Initiation of construction — Summer 2008
- Initial start-up — Late Spring 2010
- Full-scale operations — Late Summer 2010

The construction workforce will peak at 767 during Month 12 of the construction schedule; over the entire construction period, there will be an average workforce of approximately 360. The on-site workforce will consist of laborers, craftsmen, supervisory personnel, support personnel, and construction management personnel. Temporary construction laydown and parking areas will be provided south and west of the power plant site (see Figure 2-3).

The construction sequence for power plant construction includes the following general steps:

- Site Preparation: this includes detailed construction surveys, demolition of existing structures, grading, and preparation of drainage features. It is expected that the combined-cycle area will be prepared first followed by the solar field.

- Foundations: this includes excavations for large equipment (CTGs, STG, HRSG, etc.) and footings for the solar field. This work will begin on the combined-cycle plant and then move to the solar field.
- Major Equipment Installation: once the foundations are complete the larger equipment will be installed. The solar field will be assembled on-site once the foundations are installed.
- Balance of Plant (BOP): with the major equipment in place, the remaining field work will be piping, electrical, and smaller component installations.
- Testing and Commissioning: testing of subsystems will be done as they are completed. Major equipment will be tested once all supporting subsystems are installed and tested.

Construction of the Project transmission system will begin in the third month of the overall construction schedule with work on Segment 3, the southernmost segment furthest from the plant site. Transmission line construction then will proceed northward to Segment 2 and then Segment 1. Construction of the various Project pipelines will begin in the seventh month of the construction schedule.

Equipment and materials will be delivered to the Project site by truck; large components (e.g., CTG) will be brought to the Victorville area by rail and brought to the site by special transporter trucks designed for large loads.

2.4.2 Facility Operation

The VV2 Project will have a small workforce during operation. Actual power plant operations will be controlled by two or three individuals during each operating shift. Additional maintenance and supervisory personnel will be present during the day shift and, as required by specific operations or maintenance activities, during evening and night shifts. The Project is expected to employ 36 full-time personnel.

The power plant will be operated up to 7 days per week, 24 hours per day. When the plant is not operating, personnel will be present as necessary for maintenance, to prepare the plant for startup, and/or for site security.

3.0 Regulatory Setting

3.1 Ambient Air Quality Standards

The EPA has established NAAQS pursuant to the Clean Air Act. The NAAQS include both primary and secondary standards for several "criteria pollutants". The primary standards are designed to protect human health with an adequate margin of safety. The secondary standards are designed to protect property and ecosystems from effects of air pollution. NAAQS have been established for ozone, CO, NO_2, SO_2, PM10, PM2.5, and lead. Table 3-1 presents the NAAQS. Table 3-2 shows the attainment status for the Project area.

Table 3-1
National Ambient Air Quality Standards

Pollutant	Averaging Time	National Standard [1,2]	
		Primary [3]	Secondary [4]
Ozone	8-hour	0.08 ppm (157 $\mu g/m^3$)	Same
CO	8-hour	9 ppm (10 mg/m^3)	Same
	1-hour	35 ppm (40 mg/m^3)	Same
NO_2	Annual Average	0.053 ppm (100 $\mu g/m^3$)	Same
SO_2	Annual Average	0.03 ppm (80 $\mu g/m^3$)	None
	24-hour	0.14 ppm (365 $\mu g/m^3$)	None
	3-hour	None	0.5 ppm (1,300 $\mu g/m^3$)
PM10	24-hour	150 $\mu g/m^3$	Same
PM2.5	Annual	15 $\mu g/m^3$	Same
	24-hour	35 $\mu g/m^3$	Same
Lead	Quarterly	1.5 $\mu g/m^3$	Same

$\mu g/m^3$ = Micrograms per cubic meter.
mg/m^3 = Milligrams per cubic meter.
ppm = parts per million by volume
(1): National standards, other than ozone and those based on annual averages or annual arithmetic means, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.
(2): Equivalent units given in parentheses are based on a reference temperature of 25ºC and a reference pressure of 760 mm of mercury. All measurements of air quality are to be collected at a reference temperature of 25ºC and a reference pressure of 760 mm of mercury (1,013.2 millibars).
(3): National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health. Each state must attain the primary standards no later than three years after that state's implementation plan is approved by the EPA.
(4): National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant Each state must attain the secondary standards within a 'reasonable time' after implementation plan is approved by the EPA.
(5): The annual PM10 NAAQS of 50 $\mu g/m^3$ was revoked by EPA on September 21st, 2006. FR Vol. 71 Number 200 10/17/2006.

Table 3-2
Attainment Status for City of Victorville, San Bernardino County

Pollutant	Federal
Ozone	Non-attainment (Moderate) for the 8-Hour standard
CO	Unclassified/Attainment
NO_2	Unclassified/Attainment
SO_2	Unclassified
PM10	Non-attainment (Moderate)
PM2.5	Attainment
Lead	Attainment

3.2 Applicable Rules and Regulations

This section describes the regulations and standards that apply to sources of air pollution relevant to the VV2 Project. The focus is on "criteria" pollutant emissions, i.e., those pollutants for which there are ambient air quality standards set to protect health and the environment. The VV2 Project will emit negligible amounts of lead, and hence it is not discussed further.

The EPA is responsible for establishing the NAAQS and enforcing the Federal Clean Air Act (CAA). Various Federal programs have been developed to regulate sources of air pollutants, including stationary, mobile and area sources. These programs include New Source Review (NSR) and other permitting requirements, as well as emissions standards for new and modified sources, and compliance monitoring. The Federal Programs applicable to the VV2 Project are summarized in Table 3-3. Most of these Federal programs, except for PSD, have been delegated to the MDAQMD for implementation in the local area.

3.2.1 New Source Review

The Federal CAA requires any new major stationary sources of air pollution, and any major modifications to existing major stationary sources, to obtain a construction permit before commencing construction. This process is known as New Source Review (NSR). NSR refers to the pre-construction review and permitting programs under CAA Title I, Parts C and D, that must be satisfied before new construction or major modifications can begin on major sources. The Prevention of Significant Deterioration (PSD) program (CAA Title I, Part C) is EPA's NSR permitting program for sources located in areas that attain the NAAQS (attainment areas) and in areas for which there is insufficient information to determine status (unclassified areas). Its counterpart, (CAA Title I, Part D), is for sources located in areas that do not attain the NAAQS (non-attainment areas), and is often called the non-attainment NSR (NNSR) program. EPA Region IX currently issues PSD permits to applicable sources within the MDAQMD, but the non-attainment NSR program is administered by the MDAQMD.

Table 3-3
Summary of Federal Air Quality Regulations Applicable to the VV2 Project

Regulation	Applicability
Prevention of Significant Deterioration (PSD) Clean Air Act (CAA) §160-169A, 42 USC §7470-7491, 40CFR Parts 51 and 52.	Requires PSD review, facility permitting, Best Available Control Technology (BACT) and increment consumption analysis for significant emissions from new major sources
CAA, Sections 171 – 193, 42 USC, Section 7501	Requires NSR facility permitting for construction or modification of specified stationary sources. NSR applies to pollutants for which area is designated non-attainment for NAAQS
CAA, Section 401 (Title IV), 42 USC, Section 7651	Requires reductions in NO_x and SO_2 emissions to reduce acid deposition
CAA, Section 501 (Title V), 42 USC, Section 7661	Establishes a comprehensive permit program for major stationary sources
CAA, Section 111, 42 USC, Section 7411, (Title 40 CFR, Part 60)	Establishes national performance standards for new stationary sources
CAA, Section 114, 42 USC, Section 7414, (Title 40 CFR Part 64)	Requires the operation, maintenance and monitoring of emission control systems
Emergency Planning and Community Right-to-Know Act, 42 USC Chapter 116	Requires reporting of releases of toxic materials to the environment if the facility manufactures, processes or otherwise uses more than specified quantities of toxics

3.2.2 Prevention of Significant Deterioration

The PSD regulations, which can be found at 40 CFR § 52.21, apply to the construction of major sources in areas that are currently in attainment or unclassified for the NAAQS. A major source is defined as a facility with potential to emit equal to or greater than 250 tons per year (tpy) of any criteria pollutant. In addition, the rules provide a list of 28 major facility categories that are subject to the PSD provisions if they have the potential to emit greater than 100 tpy. The VV2 Project power plant is included in the list of 28 major facility categories (fossil-fuel fired, steam electric generating facility).

The PSD program is designed to prevent further significant deterioration of areas that are currently in attainment or unclassified. The PSD regulations accomplish this goal by imposition of Best Available Control Technology (BACT) and dispersion modeling analyses to ensure that allowable increments of degradation will not be exceeded.

The Project area attains the NAAQS for NO_x and CO, but does not attain the national standards for ozone or PM10. Total emissions for the Project will be greater than the 100-tons per year PSD major source threshold for NO_x and CO. Therefore, the PSD program major source requirements apply to emissions of these two pollutants.

3.2.3 Title V – Federal Operating Permits Program

Title V of the CAA Amendments of 1990 requires a Federal Operating Permit for major sources of criteria pollutants and a compliance plan for meeting applicable regulatory requirements. Covered major sources must submit an annual compliance certification and must renew the Title V permit every five years. Requirements for State/locally administered Title V programs are outlined in 40 CFR Part 70. The MDAQMD maintains its own set of regulations (i.e., District Regulation XII) applicable to Federal Operating Permits. Emissions thresholds for Title V applicability vary depending on the attainment status of the area. A Title V permit contains all of the requirements specified in different air quality regulations that affect an individual facility or project. The VV2 Project will be subject to the Title V program and will be required to obtain a Title V permit from the MDAQMD in a timely manner.

3.2.4 Title IV – Acid Rain Program

Title IV of the CAA Amendments of 1990 requires implementation of an acid rain permit program (42 USC §7651; 40 CFR Part 72). These regulations require reductions in emissions of sulfur dioxide and nitrogen oxides from subject facilities in order to reduce the adverse effects of acid deposition. Under this program, the VV2 Project must obtain emission allowances for SO_x emissions and meet monitoring requirements for NO_x. MDAQMD has been delegated by EPA to implement the Title IV program with EPA Region IX oversight. The requirements for this program are contained in MDAQMD Rule 1210.

3.2.5 New Source Performance Standards (NSPS)

The VV2 Project is also subject to specific New Source Performance Standards (NSPS). Enforcement of the NSPS has been delegated to the MDAQMD.

NSPS are Federal standards promulgated for new and modified sources in designated categories codified in 40 CFR Part 60. NSPS are emission standards that are progressively tightened over time in order to achieve on-going air quality improvement without unreasonable economic disruption. The NSPS impose uniform requirements on new and modified sources throughout the nation. These standards are based on the best demonstrated technology (BDT) for emission control. BDT refers to the best system of continuous emissions reduction that has been demonstrated to work in a given industry, considering economic costs and other factors, such as energy use. In other words, a new source of air pollution must install the best control system currently in use within that industry.

The format of the standard can vary from source to source. It can be a numerical emission limit, a design standard, an equipment standard, or a work practice standard. Primary enforcement responsibility of the NSPS rests with EPA, but this authority can be delegated to the States or local air districts. States can adopt an NSPS or impose limitations of their own, as long as the State requirements are at least as stringent as the Federal requirements. The NSPS potentially applicable to the proposed VV2 Project are summarized below.

Subpart A – General Provisions. – Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Because the proposed Project is potentially subject to Subpart KKKK – NO_x Emission Limits for New Stationary Combustion Turbines, the requirements of Subpart A will also apply. The VV2 Project operator will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A.

Subpart KKKK – NOx Emission Limits for New Stationary Combustion Turbines. The proposed combined-cycle hybrid power plant must comply with the requirements of NSPS Subparts KKKK.[1] MDAQMD emission limitations based on BACT requirements are, however, more restrictive than these NSPS requirements.

The NO_x standard for units firing natural gas, and rated at greater than 850 MMBtu/hr heat input, is 15 ppm at 15 percent O_2 (or 54 ng/J of useful output or 0.43 lb/MW-hr). Compliance is determined on a 30-unit-operating-day rolling average, where "unit operating day," is defined as a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted in the unit.

The SO_2 standard is 110 ng/J (or 0.9 lb/MW-hr) gross output. Operators can also comply with an alternative standard, limiting potential sulfur emissions to below 26 ng/J (0.06 lb/MMBtu) heat input. Fuel sulfur monitoring is required each unit operating day. However, options are available to reduce frequency or entirely avoid the necessity to monitor (e.g., representative sampling according to the schedule in Part 75, Appendix D or tariff sheet attesting that sulfur content is < 0.05 percent by weight).

At the 2 ppm level required by BACT, the VV2 Project NO_x emissions will meet the NSPS limit and CEMS will be used to ensure compliance. Pipeline quality natural gas will ensure compliance with the SO_2 standard.

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE) – Owners and operators of emergency fire-water pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

Owners and operators of emergency stationary CI ICE that are not fire-water pumps and with a displacement of less than 30 liters per cylinder and a maximum engine power less than 2,237 kW must comply with the off-road emission standards specified in 40 CFR Part 89.112 and 40 CFR Part 89.113.

Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements: (1) reduce NO_x emissions by 90 percent or more, or limit the emissions of NO_x in the stationary CI ICE exhaust to 1.6 grams per kW-hr (1.2 grams per horsepower-hour (hp-hr); and (2) reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI ICE exhaust to 0.15 g/kW-hr (0.11 g/hp-hr).

If non-emergency use of the engines is restricted to less than 50 hours or as required by fire safety testing, then the above limits do not apply. The VV2 Project will comply with this NSPS by restricting the use of the engines to emergency situations and limiting non-emergency testing to less than 50 hours per year.

3.2.6 Compliance Assurance Monitoring (CAM) Rule

The CAM Rule (40 CFR Part 64) requires facilities to monitor the operation and maintenance of emissions control and report any control system malfunctions to the appropriate regulatory agency. If the emission control system is not working properly, the CAM Rule also requires action to correct the control system malfunction. The CAM Rule applies to units that employ an active control device with uncontrolled potential to emit levels greater than applicable major source thresholds. Emission units governed by Title V operating

[1] With the promulgation of 40 CFR Part 60 Subpart KKKK in July 2006, requirements of Subparts GG and Da are superseded by this new regulation.

permits that require continuous compliance determination methods are generally compliant with the CAM Rule.

The pollutant specific emission units (PSEU) at the VV2 Project include the combustion turbines controlled with SCR systems to control NO_x emissions and oxidation catalysts to control CO and VOC. However, these PSEUs are not subject to the CAM Rule because the NO_x emissions are subject to the Acid Rain program, the CO will be continuously monitored as required by a Title V permit, and the catalyst can be shown to be working by the CO continuous emissions monitoring system (CEMS). The dry low-NO_x burners employed by the auxiliary boiler and heater and the drift eliminator installed on the cooling tower are not considered to be “active” control devices, and hence these PSEUs are exempt from the CAM Rule.

3.2.7 Toxic Chemical Release Inventory Program

The Emergency Planning and Community Right-to-Know Act (EPCRA), through the Toxic Chemical Release Inventory (TRI) program, establishes reporting requirements for toxic releases to the environment if the facility: (1) produces more than 25,000 pounds of a listed chemical per year; (2) processes more than 25,000 pounds of a listed chemical per year; or (3) uses more than 10,000 pounds of a listed chemical per year. Electric utilities, in Standard Industrial Classification (SIC) Codes 4911, 4931, and 4939, that combust coal and/or oil for the purpose of generating electricity for distribution in commerce must report under this regulation. The VV2 Project falls under SIC Code 4911, which covers establishments engaged in the generation, transmission, and/or distribution of electric energy for sale. However, the Project will not combust coal and/or oil for the purpose of generating electricity for the distribution in commerce. The VV2 Project will use ammonia, a listed chemical, so it will need to report if it uses more than 10,000 pounds of ammonia in a year.

4.0 Control Technology Evaluation

One of the substantive requirements of the PSD program is that major sources of attainment pollutants must apply BACT. As discussed previously, the Victorville area in the MDAQMD is designated as non-attainment for the NAAQS for ozone and PM10 and attainment for the NAAQS for CO, NO_2 and SO_2. Because the proposed VV2 Project has the potential to emit significant levels of NO_x and CO, BACT must be implemented for these pollutants. Emissions of SO_2 will be below the PSD significance level of 40 tpy, hence BACT is not required for this pollutant under PSD. Because NOx is a precursor to ozone, the control technology for NOx must also meet the more stringent requirements for Lowest Achievable Emission Rate (LAER).

This section evaluates NOx and CO control technology for each proposed emission unit that emits these pollutants. Several agencies, including the EPA, California Air Resources Board (ARB) and several air districts including the South Coast Air Quality Management District (SCAQMD) maintain data bases of control technology determinations. The SCAQMD has published BACT guidelines applicable to the types of equipment found at power generation facilities. While Victorville is within the MDAQMD, and thus outside SCAQMD jurisdiction, the SCAQMD guidelines were used as an additional resource for the determination of BACT/LAER emission levels for the proposed Project. SCAQMD no longer publishes “presumptive” BACT/LAER emission levels, but rather includes examples of recent BACT/LAER determinations as input to future case-by-case BACT/LAER decisions. This control technology evaluation for the VV2 Project includes a summary of previous BACT/LAER determinations from the SCAQMD’s BACT Guidelines and EPA’s RACT/BACT/LAER Clearinghouse (RBLC), as well as recent or pending decisions by the California Energy Commission.

EPA guidance recommends that control technology reviews be performed on a “top down” basis, that is, starting with the top level of control that has been demonstrated in practice on a similar emission source. If the top level of control is selected, no further analysis is required. The following BACT/LAER analysis follows the top-down methodology – however, the top level of control is proposed for each pollutant subject to control technology requirements.

4.1 Combustion Turbines and Heat Recovery Steam Generators

The proposed CTGs will operate in combined-cycle mode. In a combined cycle, hot exhaust from the CTG is ducted through a HRSG, which may also be fired, to drive a steam turbine generator. The VV2 Project will supplement steam produced in the HRSG with steam generation from a solar array. Since the CTG and HRSG are coupled together in a combined-cycle configuration, and exhaust through a single stack, they are considered to be one combustion train for purposes of the evaluation of BACT/LAER emissions control.

4.1.1 LAER for NO_x

4.1.1.1 Top-down Ranking of Achievable Control Levels

The most recent listings for combined-cycle combustion turbines in this size range provided in Part B of the SCAQMD BACT guidance include:

- Magnolia Power Project, Burbank, California – 2004; NO_x = 2 parts per million (ppm), 3-hr average
- Vernon City Power & Light, Vernon, California – 2004; NO_x = 2 ppm, 1-hr average

The Guidance also references several large combined-cycle projects operating in Massachusetts with NO_x limits of 2 ppm, including ANP Blackstone, IDC Bellingham and Sithe Mystic.

EPA's RBLC shows additional projects permitted in recent years at the 2 ppm NO_x emission rate, including:

- Duke Energy Arlington Valley Energy Facility, Maricopa County, Arizona – 2003
- Sacramento Municipal Utility District Cosumnes Plant, Sacramento County, California – 2003
- Salt River Project Santan Generating Station, Maricopa County, Arizona – 2003

The CEC shows additional projects approved or pending approval at the 2 ppm NO_x emission rate, including:

- Roseville Energy Park, Placer County, California – 2005
- El Centro Unit 3 Repower Project, Imperial County, California – 2007
- Blythe Energy Project II, Riverside County, California – 2005
- Los Esteros Critical Energy Facility, Phase II, Santa Clara County, California – 2006
- South Bay Replacement Project, San Diego County, California – pending

All of the combined-cycle combustion turbine projects listed above employ SCR for NO_x control. The basis for the emission rates for the two SCAQMD plants was LAER. See Appendix B for listings of RBLC entries and other projects in the previous four years for NO_x.

4.1.1.2 Ammonia Slip Associated with SCR

The emission of unreacted ammonia (NH_3), or "ammonia slip," is a necessary collateral emission impact of the operation of SCR, especially when NO_x is being controlled to LAER levels. Ammonia is a potential contributor to formation of particulate matter in the atmosphere by reaction with gaseous nitric acid or sulfuric acid, although most such reactions are not ammonia-limited due the consistent presence of naturally occurring ammonia in the atmosphere. A trade-off exists between the minimization of NO_x and the minimization of ammonia slip when SCR is used to control NO_x. Even though NH_3 is not a BACT/LAER applicable criteria air pollutant, regulatory agencies routinely limit NH_3 slip emissions in new permits for combined-cycle facilities.

Information from recent permits in the SCAQMD BACT Guidelines provides the following limits for NH_3:

- Magnolia Power Project, Burbank, California; NH_3 = 5 ppm
- Vernon City Power & Light, Vernon, California; NH_3 = 5 ppm

Four facilities in Massachusetts are listed in the RBLC as being permitted at 2 ppm @ 15% O_2 for ammonia slip:

- ANP Blackstone Energy Company, Worcester, Massachusetts – 1999
- ANP Bellingham Energy Company, Norfolk, Massachusetts – 1999
- Cabot Power Corporation, Suffolk, Massachusetts – 2000
- Sithe Mystic Development, Suffolk, Massachusetts – 1999

None of these facilities, however, are equipped with duct burners. Duct burners add to the total stack emissions of NO_x from a combined-cycle system, and complicate the constant temperature window needed to optimize SCR performance in the heat recovery steam generator. Five ppm is determined to be the lowest NH_3 slip level permitted for combined-cycle turbines with duct burners that seek to reduce NO_x to 2 ppm.

The CEC has approved or is pending approval of several projects at an NH_3 emission rate of 10 ppm, including:

- Roseville Energy Park, Placer County, California – 2005
- Blythe Energy Project II, Riverside County, California – 2005

- Los Esteros Critical Energy Facility, Phase II, Santa Clara County, California – 2006

The El Centro Unit 3 Repower Project, Imperial County, California has a 5 ppm NH_3 emission rate that was proposed by the applicant and is expected to be required by the local air pollution control agency. All these facilities will be equipped with duct burners.

Since ammonia is not a criteria air pollutant subject to BACT/LAER, and since the VV2 Project must minimize emissions of NO_x from both the combustion turbines and fired heat recovery steam generators, ammonia slip emissions of up to 5 ppm are proposed.

4.1.1.3 NO_x LAER Determination for Normal Operation

The VV2 Project proposes a BACT/LAER emission limit of 2.0 ppmvd (15% O_2) NO_x on a 1-hour averaging time using SCR, and an ammonia slip limit of 5 ppmvd (15% O_2) during steady-state, normal operating conditions. Normal operating conditions exclude periods of startup, shutdown and malfunction. The same aggressive limit is proposed when duct burners are also firing in the HRSG.

4.1.1.4 NO_x LAER Determination for Startup and Shutdown

The use of SCR to control NO_x is not technically feasible when the surface of the SCR catalyst is outside of the manufacturer's recommended operating temperature range. Outside of these temperatures, NH_3 cannot be introduced to control NO_x, since the NH_3 will not react with the NO_x completely. Therefore, SCR cannot be used to control NO_x emissions during gas turbine startup or shutdown, when the SCR catalyst temperature is below the minimum operating temperature.

NO_x is emitted in diffusion flame mode in the turbine combustor during the first phases of startup, albeit at low fuel input rates. When turbine load reaches conditions that are predetermined by the turbine control system, the combustors switch to dry low-NO_x (lean pre-mix DLN) operation, and NO_x emissions are controlled with the DLN combustion system of the combustion turbine. Once conditions reach minimum temperature at which NH_3 injection can be initiated, normal operation of the SCR system is rapidly achieved.

The VV2 Project is proposing to permit a gas-fired auxiliary boiler and solar array that will be used to preheat the combined-cycle systems' steam seals and piping, as well as a novel heat recovery steam generator that is designed to enable faster startups. This technology is referred to by the manufacturer (GE) as their "Rapid Start Process" or RSP, and is expected to reduce the duration of startups compared with conventional combined-cycle units. By shortening the duration of startup times, the RSP technology may be capable of reducing total startup emissions on the order of 50 percent.

There are no other technically feasible control techniques to further reduce emissions of NO_x during startup and shutdown. Mass emission rate limits, in pounds per event, proposed during startup and shutdown and the specification of GE's RSP technology therefore represent LAER for emissions of NO_x during the short-term startup and shutdown events. The following emission rate limits during these periods are proposed:

Hot/warm Startup:	40.0 lb/event per turbine
Cold Startup:	96 lb/event per turbine
Shutdown:	57 lb/event per turbine

4.1.2 BACT for CO

CO is formed as a result of incomplete combustion of fuel within the gas turbine generating systems.

4.1.2.1 Top-down Ranking of Achievable Control Levels

In the last four years, projects have been permitted for CO levels ranging from 2.0 to 4.0 ppm. For example, CO listed for similar combined-cycle turbines in the SCAQMD BACT Guidelines include:

- Magnolia Power, Burbank, California, 2004; CO = 2.0 ppm, 1-hr average
- Vernon City Power & Light, Vernon, California, 2004; CO = 2.0 ppm, 3-hr average

Many facilities are listed in the RBLC since 2002 with CO permit limits of 2 ppm @ 15% O_2. Among the most recent projects listed are:

- COB Energy Facility, Klamath, OR – 2003
- Sumas Energy 2 Generation Facility, Whatcom, WA – 2003

The CEC also has a pending approval at the 2 ppm CO emission rate for the South Bay Replacement Project, San Diego County, California.

Duct burners will emit additional CO, which will increase the uncontrolled emission levels entering the oxidation catalyst. Several recent projects, including the Duke Energy Arlington Valley Energy Facility, Maricopa County, AZ and Copper Mountain Power, Clark County, NV have CO permit limits of 3.0 ppm when duct firing and 2.0 ppm when not. A complete listing of RBLC projects, as well as others, is included in Appendix B.

4.1.2.2 CO BACT Determination for Normal Operation

The VV2 Project proposes CO BACT emission limits of 2.0 ppmvd (corrected to 15% O_2) over a one-hour averaging time without duct burners, and 3.0 ppmvd (corrected to 15% O_2) over a one-hour averaging time when duct burners are firing. These emission limits will be achieved with use of an oxidation catalyst.

4.1.2.3 CO BACT Determination for Startup and Shutdown

CO emissions during startup and shutdown are controlled to a lesser extent than during normal operation because the oxidation catalyst is below its normal operating temperature range. Similar to the emissions of other pollutants, the RSP technology may be capable of reducing total startup CO emissions on the order of 50 percent.

There are no other technically feasible control techniques to further reduce emissions of CO during startup and shutdown. The mass emission rate limits, in pounds per event, proposed to limit CO emissions during startup and shutdown therefore represent LAER, which goes beyond the BACT levels required for this Project.

The following CO emission rate limits during these periods are proposed:

Hot/warm Startup:	329.0 lb/event per turbine
Cold Startup:	410.0 lb/event per turbine
Shutdown:	337.0 lb/event per turbine

4.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include a 35 MMBtu/hr auxiliary boiler and a 40 MMBtu/hr Heat Transfer Fluid (HTF) heater. Both will be fired by pipeline quality natural gas. The auxiliary boiler will operate a maximum of 500 hours per year and the HTF heater will operate no more than 1,000 hours per year. The auxiliary boiler is primarily designed to shorten the duration of startups as part of GE's RSP technology; therefore, the boiler itself is control technology designed to minimize emissions during startup.

4.2.1 LAER for NO_x

NO_x is primarily formed within a natural gas combustion process in two ways: (1) the oxidation (within the high temperature environment of the flame) of elemental nitrogen contained in the combustion air (this is referred to as thermal NO_x); and (2) the oxidation of nitrogen contained in the fuel (referred to as fuel NO_x). The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature. For conventional boilers fired exclusively with natural gas, it is generally assumed that fuel NO_x formation is of a minimal magnitude.

In general, alternative approaches to minimizing NO_x emissions from a natural gas-fired unit are as follows:

- Combustion modifications / combustion-based control systems
- Flue gas treatment

Combustion-based ("front-end") control mechanisms available for reducing the formation of thermal NO_x emissions include: (1) reduction of local nitrogen concentrations at peak temperature, (2) reduction of local oxygen concentrations at peak temperature, (3) reduction of residence time at peak temperature, and (4) reduction of peak temperature. Because it is quite difficult to reduce nitrogen levels, most front-end NO_x control techniques have focused on the other three mechanisms.

4.2.1.1 Available Control Technologies for NO_x

The primary front-end combustion controls for small scale natural gas combustion sources include low-NO_x burners (LNBs), flue gas recirculation (FGR), and reburn technology (which provides an additional level of staged combustion). All burner manufacturers now offer standard LNBs that limit NO_x formation to a range of approximately 0.035 to 0.05 pounds per million Btu heat input (lb/MMBtu) when firing natural gas. New state-of-the-art LNBs, commonly referred to as 9 ppm ultra low-NO_x "California" burners, can achieve NO_x emission rates in the range of what may be achieved through application of flue gas treatment (SCR). Candidate control technologies that were evaluated are summarized in the following sections.

Selective Catalytic Reduction: The key limitation relative to the technical feasibility of SCR for the proposed auxiliary boiler or HTF heater is that the temperature of the exhaust gas will be below the low end of the proper temperature range for the SCR catalyst. More specifically, it is expected that the temperature of the boiler or heater exhaust gas will be on the order of 350^{o}F while the minimum temperature for effective NO_x reduction with SCR is approximately 600^{o}F. Because the temperature of the exhaust gas exiting the units will be well below the low end of the proper SCR temperature range and the auxiliary units will operate only for a limited number of hours per year, and then primarily to shorten the duration of combined-cycle startups as part of an overall LAER control strategy, SCR has never been attempted or considered on any similar unit. It is doubtful that the proposed auxiliary units would even operate at steady-state conditions long enough to introduce NH_3 to an SCR system. This technology is therefore technically infeasible for application to the proposed auxiliary boiler or HTF heater.

Ultra Low-NO_x Burners with Internal Flue Gas Recirculation: Low-NO_x burners that incorporate internal flue gas recirculation are well established for application to industrial-sized package boilers and heaters.

Commercially available ultra LNBs are now considered technically feasible, and are capable of limiting NO_x emissions to 9 ppm, which is considered to represent LAER in this type of application.

Reburn Technology: Reburn technology involves staging combustion through the combustion of fuel through a second elevation of burners, which limits the formation of thermal NO_x. Package boilers and heaters do not have the required vertical space or furnace volume for the addition of a second burner, and thus NO_x control through the use of reburn technology is not considered to be technically feasible for a package boiler application.

4.2.1.2 Top-down Ranking of Achievable Control Levels

MDAQMD and EPA do not dictate a specific control technology that must be used to achieve established LAER emission rates, and encourage selection of the qualifying technology with the least adverse collateral impacts. For operation of natural gas-fired auxiliary units that will operate very few hours per year, and especially for units that are themselves emission control equipment, the best technology selection to achieve LAER is the 9 ppm ultra-low NO_x burner.

The most recent listings for gas-fired boilers in this size range provided in Part B of the SCAQMD BACT guidance include:

- Los Angeles County Internal Services, Los Angeles, California, 2004; NO_x = 9 ppm
- Clayton Industries, Chatsworth, California, 2002; NO_x = 9 ppm

Several natural gas-fired industrial boilers have also been permitted in Massachusetts with 9 ppm “California Burners” as BACT. The proposed auxiliary boiler will operate to reduce startup duration, and the boiler and heater will operate for very limited hours per year. No similar sources were identified in EPA’s RBLC with NO_x emission limits less than 9 ppm.

4.2.1.3 NO_x LAER Determination for Normal Operation

The application of 9 ppm “California” ultra low NO_x burner technology with limited hours of operation and exclusive use of pipeline quality natural gas represents LAER for the proposed auxiliary boiler and HTF heater. The auxiliary boiler will be equipped with LNBs (9 ppm @ 3% O_2) and will have a NO_x emission rate of 0.011 lb/MMBtu. The HTF heater will also emit less than 0.011 lb/MMBtu of NO_x. The use of low NO_x burners and the emission limit of 0.011 lb/MMBtu represent LAER for the proposed auxiliary boiler and HTF heater.

4.2.2 BACT for CO

CO emissions in a natural gas burner result from incomplete combustion of organic compounds contained in the gas being burned. Three principal factors contribute to the failure to achieve completion of combustion: (1) insufficient air supply; (2) insufficient residence time; and (3) thermal quenching of the combustion products.

The minimization of CO emissions from a natural gas-fired unit is accomplished by combustion design, including furnace design and instrumentation, and operational techniques that ensure complete combustion. Effective design of the unit to achieve the lowest possible CO emissions involves the minimization of the three factors cited above. A major issue, however, in the design of an emissions control system is that there exists a tradeoff between NO_x emissions and CO emissions. The mechanisms by which NO_x emissions are minimized tend to result in an increase in the generation of CO emissions.

Fuels require a minimum level of air input to the combustion zone to allow for completion of combustion. Because of the dynamics of the combustion process and the chemical composition of both air and fuel, this minimum level is above the stoichiometric level (i.e., the level at which there is just sufficient oxygen for the elements of the fuel to burn). For natural gas burners, at least 20 percent excess air is typically needed for completion of combustion. The level of excess air is site-specific and can only be established by field tests of the unit. To complete combustion, therefore, the auxiliary boiler must be designed to provide more than 20 percent excess air. LNBs are intended, however, to operate at very low excess air levels (10 percent to 15 percent excess air). Therefore, the system must be designed to maintain excess air within these levels to keep an appropriate balance between control of NO_x and CO. Sufficient time must be provided for the mixing and combustion to take place. A residence time of at least 0.5 seconds in the upper section of the combustion zone is typically required to complete combustion. The system design must take into account both furnace volume and flow mechanics to provide at least this much time. Incomplete combustion can also occur due to the impingement of a flame onto a cold surface. This most often involves the impingement of the flame onto cold furnace walls. Premature quenching of the flame will release CO into the stack gases. The temperature of the gas stream is lowered sufficiently to freeze intermediate combustion products, including CO. The problems with flame impingement are acute with LNBs. Flame lengths with LNBs are longer due to the delayed mixing of air into the flames. It is necessary, therefore, to carefully size the burners to account for the added length of an LNB flame. The control technology alternatives that were considered include combustion control and oxidation catalyst.

4.2.2.1 Available Control Technologies for CO

Similar to SCR technology, oxidation catalyst technology is not technically feasible for application to small auxiliary package boilers or heaters, especially units that will operate relatively few hours per year, and then primarily as part of GE's RSP technology designed to minimize emissions from the combined-cycle systems during startup. Good combustion control, as achieved with state-of-the-art "California" burners, thus represents the only technically feasible CO control technology applicable to the VV2 Project's proposed small auxiliary package boiler and HTF heater.

4.2.2.2 Top-down Ranking of Achievable Control Levels

The most recent listings for gas-fired boilers in this size range provided in Part B of the SCAQMD BACT guidance include:

- Los Angeles County Internal Services, Los Angeles, California, 2004; CO = 100 ppm
- Clayton Industries, Chatsworth, California, 2002; CO = 100 ppm

The proposed auxiliary boiler and HTF heater will each operate for a very limited number of hours per year. No similar sources were identified in EPA's RBLC with emission limits less than 100 ppm.

4.2.2.3 CO BACT Determination for Operation

The application of 100 ppm "California" ultra LNB technology with limited hours of operation and exclusive use of pipeline quality natural gas represents BACT for CO for the proposed auxiliary boiler and the HTF heater. CO emissions from the auxiliary boiler and HTF heater will be minimized by maintaining sufficient oxygen supply and residence time in the combustion chamber, thus allowing complete combustion of the natural gas fuel. Each unit will emit less than 0.074 lb/MMBtu of CO. BACT will be met through effective equipment design and good combustion practices.

4.3 Emergency Diesel Generator and Fire-Water Pump Engines

The VV2 Project will include an emergency diesel generator sized at approximately 2,000 kW and a diesel fire-water pump rated at approximately 135 kW. These emergency diesel engines will each operate for a maximum of 50 hours per year for testing (or as required by fire safety regulations).

New Source Performance Standards (40 CFR 60 Subpart IIII) were promulgated July 11, 2006 (71 FR 39154) by EPA for stationary diesel engines. The new MACT standard (40 CFR 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutant for Stationary Reciprocating Internal Combustion Engines) would not apply to the VV2 Project since the facility will not be a major source of HAP.

Title 17, CCR Section 93115, which is an air toxics control measure, requires new stationary emergency standby diesel-fueled engines to meet the following standards: $\leq$0.15 g PM/bhp-hr (0.20 g/kW-hr), compliance with the appropriate California off-road engine certification standards for hydrocarbons, NO_x and CO as the same model year and horsepower rating, as specified in 13 CCR Section 2423, and a limit of 50 hours/year for maintenance and testing. New stationary emergency standby engines that operate more than 50 hours/year are required to meet a PM emission limit of 0.01 g/bhp-hr (0.0134 g/kW-hr). Annual emissions from the emergency diesel generator and fire-water pump engines have been calculated based on a limitation of 50 hours/year for maintenance and testing.

The California emission standards specified in 13 CCR Section 2423 and the PM emission limits specified in 17 CCR Section 93115 are at least as stringent as the Federal New Source Performance Standards in 40 CFR 60 Subpart IIII. Therefore, compliance with the California emission standards and limits constitutes LAER for the emergency diesel generator and fire-water pump engines.

4.3.1 LAER for NO_x

The emergency diesel generator engine will meet the California Tier 2 limit of 6.4 g/kW-hr of NO_x + NMHC for 2006-2010 model year diesel engines above 560 kW. The fire-water pump engine will meet the California Tier 3 limit of 4.0 g/kW-hr for NO_x + NMHC emissions for 2006-2010 model year diesel engines between 130 and 224 kW. Use of engines that comply with these emission limits plus an enforceable operating restriction of 50 hours per year for non-emergency use such as maintenance and testing constitutes LAER for NO_x emissions for both the emergency generator and the fire-water pump engines.

4.3.2 BACT for CO

The emergency diesel generator engine will meet the California Tier 2 limit of 3.5 g/kW-hr of CO for 2006-2010 model year diesel engines above 560 kW. The fire-water pump engine will meet the California Tier 3 limit of 3.5 g/kW-hr for CO emissions for 2006-2010 model year diesel engines between 130 and 224 kW. Use of engines that comply with these emission limits plus an enforceable operating restriction of 50 hours per year for maintenance and testing constitutes LAER for CO emissions for both the emergency generator and the fire-water pump engines.

4.4 Evaporative Mechanical Draft Cooling Tower

The VV2 Project will utilize reclaimed water from the nearby VVWRA wastewater treatment facility for steam turbine condenser cooling and will employ a ten cell evaporative (wet) cooling tower. Cooling towers emit trace amounts of solid particulate matter due to release of the dissolved solids (salts) in small droplets that escape the mist eliminator at the top of the tower, referred to as cooling tower drift. In theory, these small droplets may evaporate (rather than falling back to earth as liquid droplets), thus releasing dissolved salts as solid particulate matter. PM10/PM2.5 is the only pollutant of concern from wet cooling towers, and hence is not addressed in this BACT/LAER evaluation for NO_x and CO.

4.5 Summary of BACT/LAER Emission Rates

A summary of the BACT/LAER emission rates proposed for the VV2 Project based on the above evaluation are provided in Table 4-1.

Table 4-1
Summary of BACT/LAER Emissions Rates for the VV2 Project

Source	NO_x	CO
Combined-Cycle Units (Gas Turbines and HRSGs)	2.0 ppm, 1-hr avg	3.0 ppm, 1-hr avg
Auxiliary Boiler and HTF Heater	0.011 lb/MMBtu	0.074 lb/MMBtu
Emergency diesel generator	6.4 g/kW-hr NO_x +NMHC	3.5 g/kW-hr
Emergency fire-water pump engine	4.0 g/kW-hr NO_x +NMHC	3.5 g/kW-hr
Cooling Tower	n/a	n/a

5.0 Emission Calculations

5.1 Criteria Pollutant Emissions

This section provides a discussion of the NO_x and CO emissions calculated for the VV2 Project during normal operations. Appendix C provides the calculation of all criteria pollutant emissions for the project.

5.1.1 Combustion Turbines and Duct Burners

Emissions from the VV2 Project combustion turbine units were based on emission guarantees from GE and process information provided by Bibb and Associates, Inc. Annual emissions were calculated for two scenarios: (1) continuous operation of both combustion turbines throughout the year (i.e., no startups, shutdowns or offline periods); and (2) annual operations that include the maximum anticipated number of startups and shutdowns, offline periods prior to each startup, and continuous operation for the rest of the year.

Emissions for continuous operation throughout the year were based on both combustion turbines operating at full load for 8,760 hours per year with 2,000 hours of duct burning at the annual average temperature of 77 °F.

Annual emissions accounting for startups, shutdowns, and offline periods prior to startups were based on:

- Hot Start and Warm Start - 80 minute startup duration with 260 hot/warm startups per unit per year (total of 346.7 hours per year for hot or warm starts). For each hot or warm start the turbines are assumed to be offline for an average of 6 hours prior to the startup (total of 1,560 hours per year offline prior to hot or warm starts).
- Cold Start - 110 minute startup duration with 50 cold startups per unit per year (total of 91.7 hours per year for cold starts). For each cold start, the turbines are assumed to be offline for an average of 48 hours (total of 2,400 hours per year offline prior to cold starts).
- Shutdown - 30 minute shutdown duration with 310 shutdowns per unit per year (total of 155 hours per year for shutdowns).
- Continuous Operation with Duct Burning - 2,000 hours per year.
- Continuous Operation without Duct Burning - 2,207 hours per year.

Emissions for both cases and the higher emissions for the two cases are summarized in Table 5-1. Maximum hourly emissions from the two turbines are shown in Table 5-2. As seen in the table, maximum emissions for NO_x occur when there are continuous operations. It is unusual that NO_x would not be higher when accounting for startup and shutdown events. The VV2 Project is unusual in this regard because of the GE Rapid Start Process option, which reduces the time needed in startup mode. CO emissions are greatest when startups and shutdowns are included even with the Rapid Start option since these emissions are so much greater during startup before the oxidation catalyst is fully functional. Details of the operation emission calculations for the turbines and duct burners are in Appendix C.

Table 5-1
Maximum Annual Emissions from Combustion Turbines

Operating Scenario	NO_x (tpy)	CO (tpy)
Continuous Operation all Year	107.4	74.3
Operation with Startup/Shutdown and Offline Periods	87.6	253
Maximum Annual Emissions [a]	**107.4**	**253**
a. "Maximum Annual Emissions" is the largest total in either the first or second line of this table.		

Table 5-2
Maximum Hourly Emissions from Two Combustion Turbines

Operating Mode	NO_x (lb/hr)	CO (lb/hr)
Full Load Operations		
Without duct firing	23.1	15.3
With duct firing	29.2	26.7
Startup [a]	105.0	494
Shutdown [a]	228.0	1,348
a. Maximum hourly emissions for startup and shutdown were used for modeling of short-term NAAQS. However, the lb/event values given in Section 4.1 are proposed for permit limits.		

5.1.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include a natural gas-fired auxiliary boiler in order to facilitate rapid startup of the gas turbines. It will operate a maximum of 500 hours per year and will have a heat input of 35 MMBtu/hr. NO_x emissions are based on 9 ppmvd @ 3% O_2 and CO emissions are based on 100 ppmvd @ 3%. Auxiliary boiler emissions are presented in Table 5-3.

The HTF heater will operate a maximum of 1,000 hours per year and will have a heat input of 40 MMBtu/hr. NO_x emissions are based on 9 ppmvd @ 3% O_2 and CO emissions are based on 100 ppmvd @ 3% O_2. HTF heater emissions are presented in Table 5-4.

Table 5-3
Maximum Hourly and Annual Auxiliary Boiler Emissions

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	0.011	0.38	0.1
CO	0.074	2.59	0.65

Table 5-4
Maximum Hourly and Annual HTF Heater Emissions

Pollutant	Emission Factor (lb/MMBtu)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	0.011	0.44	0.22
CO	0.072	2.88	1.44

5.1.3 Emergency Diesel Generator and Fire-Water Pump Engine

The VV2 Project's emergency diesel generator will operate a maximum of 300 hours per year and will have an output of 2 MW. NO_x and CO emission factors were set equal to the California Tier 2 emission limits, with the assumption that 95 percent of the emission limit for NO_x + NMHC is NO_x. Emergency diesel generator emissions are presented in Table 5-5**.**

The emergency diesel firewater pump engine will operate a maximum of 300 hours per year and will have an output of 182 hp. NO_x and CO emission factors were set equal to the California Tier 3 emission limits, with the assumption that 95 percent of the emission limit for NO_x + NMHC is NO_x. Emergency diesel fire-water pump engine emissions are presented in Table 5-6**.**

Details of the emergency diesel generator and fire-water pump emission calculations are in Appendix C.

Table 5-5
Maximum Hourly and Annual Emergency Diesel Generator Emissions

Pollutant	Emission Factor (g/hp-hr)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	4.53	26.79	4.02
CO	2.61	15.42	2.31

Table 5-6
Maximum Hourly and Annual Emergency Diesel Fire-water Pump Emission

Pollutant	Emission Factor (g/hp-hr)	Hourly Emission Rate (lb/hr)	Annual Emissions (tpy)
NO_x	2.83	1.14	0.17
CO	2.61	1.05	0.16

5.1.4 PSD Emissions Summary

Table 5-7 shows the annual potential to emit for the VV2 Project for the PSD pollutants. The VV2 Project will be a major source (more than 100 tpy) of NO_x and CO.

Table 5-7
Total Annual Potential Emissions, Normal Operation

Source	NO_x (tpy)	CO (tpy)
Gas Turbines and HRSGs	107.4	252.7
Auxiliary Boiler	0.10	0.63
HTF Heater	0.22	1.44
Emergency Generator	4.02	2.31
Fire-Water Pump Engine	0.17	0.16
Total	111.9	257.3

5.2 Hazardous Air Pollutant Emissions

Emissions of hazardous air pollutants (HAP) that may be associated with the VV2 Project include combined-cycle combustion turbines, auxiliary boiler, heat transfer fluid (HTF) heater, and cooling tower. No appreciable quantity of HAP emissions are expected to be emitted from operation of the emergency engines, solar field array, oil/water separator, or emergency fire-water pump fuel tank. Detailed calculations in support of HAP emissions discussed below are provided in Appendix C.

5.2.1 Combustion Turbines

All combustion-related HAP emissions associated with the combustion of natural gas in the turbine generators were calculated using emission factors from AP-42, Section 3.1, Stationary Gas Turbines (EPA, 2000a). Although the oxidation catalyst will reduce the emissions of most HAPs, the exact control efficiency is unknown. EPA found that formaldehyde emissions will be reduced by a 90% control factor due to installation a catalytic oxidation system, so this reduction was applied to the uncontrolled AP-42 emission factor for this individual HAP (EPA, 2000b).

For the purposes of determining the potential maximum ambient concentrations of chemical substances emitted by the combustion turbines, the turbines were assumed to operate at base load conditions with a higher heating value (HHV) and an ambient temperature of 65°F. For annual emissions, the annual average natural gas consumption rate of 1.7 MMscf per hour per turbine plus 0.54 MMscf per hour per duct burner (2.25 MMscf per hour combined) was used, assuming that the continuous operation of both gas turbine/burner units. Duct burner fuel usage was incorporated into the emission estimates assuming 8,760 hours of turbine operations and 5,000 hours of duct burner operations per year at the maximum firing rate.

5.2.2 Auxiliary Boiler and HTF Heater

The VV2 Project will include an auxiliary boiler unit that will be used to provide sealing steam earlier in the start process, and a heater used to increase the temperature of the heat transfer fluid (HTF) received from the solar field to approximately 740° F as it circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure steam. Both the HTF heater and auxiliary boiler will fire exclusively on natural gas. Emissions for these units were based on operating conditions that represent the maximum emissions profile used for the VV2 Project. The emissions from the boiler were based on an assumed maximum of 500 hours per year of operation, and 1,000 hour per year for operation of the HTF heater.

5.2.3 Cooling Towers

Concentrations of toxics present in the cooling tower make-up water were obtained from an effluent water quality analyses from the Victor Valley Water Reclamation Authority (VVWRA), which will provide reclaimed water for the VV2 Project. Emission rates were calculated from the effluent water analysis, re-circulation rate, drift control efficiency, and maximum expected total dissolved solids (TDS) concentration. Hourly and annual emissions rates for sources were converted to a modeled emission rate in pounds per year (lb/year) for use in evaluating long-term risks, and pounds per hour (lb/hour) for use in short-term health impact modeling.

The emission estimates assumed the cooling tower was operated at the maximum recirculation rate for 8,760 hours per year. Cooling tower emissions were estimated based on a mass balance technique using the water supply quality, cooling tower maximum cycles of concentration(s), water recirculation rate (gallons per minute, gpm), and mist eliminator drift rate (0.0005%). Potential emissions from the cooling tower were identified based on an effluent water quality analysis of reclaimed water from the VVWRA for the years 2004-2005.

5.2.4 HAP Emissions Summary

The VV2 Project will not be a major source of HAP emissions. The emissions inventory (Appendix C) shows total HAP emissions of 7.8 tons per year (tpy). The primary contributor to emissions is toluene with a HAP emission of 2.6 tpy, or 33% of total HAP emissions for the VV2 Project. Regulatory major source thresholds are 10 tpy for any single HAP and 25 tpy for total HAP emissions. The VV2 Project is therefore 74% and 69% below major source thresholds for single and total HAP emissions, respectively.

6.0 Air Quality Impact Analysis

Under the PSD program, sensitive areas such as national parks and wilderness areas over a certain size have been designated as Class I areas. As such, they receive additional protection of the air quality and air quality related values in these areas. All others areas of the U.S. have been designated Class II. The air quality impact assessment (AQIA) for the VV2 Project has been divided into two parts: 1) the Class II area AQIA and 2) the Class I area AQIA.

6.1 Class II Area Impact Assessment

The detailed methodology for the Class II area AQIA is documented in the modeling protocol, "Class II Area Dispersion Modeling Protocol for the Proposed Victorville 2 Hybrid Power Project". A copy of this protocol was submitted to the CEC, EPA and MDAQMD on January 17, 2007. As of April 2007, no comments have been received on this protocol from these three agencies. The analyses were conducted in accordance with the EPA Guideline on Air Quality Models (GAQM; as incorporated in Appendix W of 40 CFR Part 51; EPA, 2005).

The AERMOD model (version 04300) was applied with a three-year sequential hourly meteorological data set, consistent with Appendix B of the CEC's Guidelines (2000). Three years (2002-2004) of wind speed, wind direction and temperature data from the nearby Victorville Park Avenue meteorological station were obtained from MDAQMD. The meteorological tower has an anemometer height of 16.9 meters. The tower data were supplemented with National Weather Service (NWS) data from General William J. Fox Field in Lancaster, CA to fill in missing data and to provide cloud cover and cloud ceiling height data also required for the modeling. Concurrent upper air data from Mercury Desert Rock Airport in Mercury, NV were also used as required for the dispersion modeling. Note that although 2005 meteorological data were available, this year was not used because of the poor data recovery of the upper air data at Mercury Desert Rock Airport during that year. As discussed in the Class II area modeling protocol, the surface and upper air data were processed with the AERMOD meteorological processor, AERMET (version 04300).

A comprehensive Cartesian receptor grid extending to approximately 20 km from the proposed combustion turbine stacks was used in the AERMOD modeling to assess maximum ground-level pollutant concentrations. The 20-km receptor grid was more than sufficient to resolve the maximum impacts and any significant impact area for PM10.

The Cartesian receptor grid consisted of the following receptor spacing:

- Fenceline to 3,000 meters at 100 meter increments
- Beyond 3,000 meters to 5,000 meters at 200 meter increments
- Beyond 5 kilometers to 10 kilometers at 500 meter increments
- Beyond 10 kilometers to 20 kilometers meters at 1,000 meter increments

Discrete receptors were placed approximately every 50 meters along the plant fenceline for increased resolution of impacts along this boundary. Figures that illustrate the receptors are provided in the modeling protocol. Terrain elevations from Digital Elevation Model (DEM) data acquired from USGS were processed with AERMAP (version 02107) to develop the receptor terrain elevations and corresponding hill height scale required by AERMOD. All of the DEM files were for UTM Zone 11 and are referenced to Datum NAD27. The DEM files are included on the modeling archive CD (Appendix D).

The background air quality concentrations used in the National Ambient Air Quality Standards (NAAQS) analysis are given in Table 6-1. In all cases, the maximum concentrations were monitored in 2003.

AERMOD was applied with the EPA recommended default options. Model iterations were conducted for each year of meteorological data to identify the maximum impacts over all 3 years for the pertinent averaging periods.

Table 6-1
Maximum Concentrations From 2003 – 2005

Pollutant	Averaging Period	Yearly Monitored Concentration (µg/m^3)		
		2003	2004	2005
NO_2	Annual	41	40	36
CO	1-hour	4,485	2,760	2,875
	8-hour	2,415	1,955	1,840

6.1.1 Modeling Methodology

Air quality modeling during operation was conducted with AERMOD to demonstrate compliance with the NAAQS and PSD increments in the local (Class II) area. The VV2 Project includes the following air emission sources that were included in the modeling analysis:

- Two combined-cycle combustion turbines, each with heat recovery steam generators
- Auxiliary boiler
- Emergency generator engine
- Fire-water pump engine
- Heat transfer fluid heater
- Cooling tower (PM10 only)

EPA has established Significant Impact Levels (SILs) for air quality impacts analyses. A SIL for a given pollutant and averaging period is defined as an ambient concentration produced by a source below which the source is assumed to have an insignificant impact. In accordance with standard modeling procedures for ambient air quality standards compliance analyses, if modeling of VV2 Project sources alone (proposed CTGs/HRSGs and ancillary combustion equipment) indicates that the maximum modeled concentrations for a specific pollutant are below the SILs, no further analysis is required for that pollutant. If modeling indicates that the SIL for any pollutant/averaging period is exceeded, then a cumulative modeling study is required to determine the combined impact of the Project sources plus other major nearby background sources for compliance with the NAAQS and PSD increments. The maximum concentrations determined through cumulative modeling are then summed with representative background concentrations to account for non-modeled source contributions for NAAQS compliance. These criteria for the impact analyses are shown in Table 6-2.

In addition to addressing air quality impacts associated with normal facility operations, modeling was conducted to assess the maximum air quality impacts during startup/shutdown of the combustion turbines.

Table 6-2
Ambient Air Quality Impact Criteria (μg/m^3)

Pollutant	Averaging Period	PSD Class II Significant Impact Levels	PSD Class II Increments	NAAQS	
				Primary	Secondary
NO_2	Annual	1	25	100	100
CO	1-hour	2,000	--	40,000	--
	8-hour	500	--	10,000	--

6.1.1.1 Source Characterization

Air quality modeling for NAAQS and PSD increment compliance during operation was conducted using the AERMOD model (version 04300). The stack parameters and emission rates input to AERMOD for the combustion turbines for normal operations are summarized in Table 6-3. Turbine emission rates and flue gas characteristics were derived for a range of ambient temperatures for natural gas fuel for three operating load points (100 percent, 75 percent and 50 percent) that included variable operating factors such as duct firing, evaporative cooling and solar energy input (See Appendix C). For the dispersion modeling, a worst case composite of emissions and stack data were developed for each of the three load cases to add a measure of conservatism to the analysis. That is, for each load, the highest emission rate and lowest exhaust parameters were identified for the expected range of ambient temperatures and operational cases. Each load was modeled to determine the worst-case for each pollutant to define the turbine stack parameters and emission rates for all Project sources for modeling maximum short-term (≤24-hour) impacts. For modeling annual average impacts for the combustion turbines, stack parameters based on 100 percent load for the representative annual average temperature (77°F) were used as they are most representative of annual average operations.

The stack parameters and emissions data for the ancillary equipment are listed in Table 6-4. These stack parameters are based on operation of the ancillary equipment at 100 percent load. The plot plan for the power block is contained in Appendix A.

Table 6-3
Stack Parameters and Emissions Data for the Combustion Turbines

Parameter		Value		
		Unit 1 (West)		Unit 2 (East)
UTM Coordinate East (meters) [a]		466,040.77		466,080.94
UTM Coordinate North (meters) [a]		3,832,160.30		3,832,159.92
Stack Base Elevation (ft)		2,802		2,802
Stack Height (ft)		145		145
Stack Diameter (inches)		222		222
		Load		
		100% [b]	**75%**	**50%**
Exit Temperature (°F)		174.5 / 174.6	180.1	171.8
Exit Velocity (ft/sec)		58.14 / 60.47	45.75	38.65
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	15.6 / 107.4	10.22	8.12
	CO	14.25 / 252.7	6.22	4.95

a. Coordinates for UTM Zone 11 referenced to Datum NAD27

b. Representative data are provided for worst-case short-term and annual average conditions. Emissions listed are lb/hr and tpy.

Table 6-4
Stack Parameters and Emissions Data for the Ancillary Equipment

Parameter		Auxiliary Boiler	Emergency Generator	Fire-Water Pump	Heater
UTM Coordinate East (m) [1]		466,142.21	466,078.50	466,112.98	466,134.72
UTM Coordinate North (m) [1]		3,832,087.48	3,832,041.01	3,832,164.05	3,832,196.84
Stack Base Elevation (ft)		2802	2802	2802	2802
Stack Height (ft)		30	30	30	30
Stack Diameter (inches)		20.76	21.48	5.64	21
Exit Temperature (°F)		300	761.7	761.7	300
Exit Velocity (ft/sec)		66.6	100	100	74.38
Pollutant Emissions (lb/hr / tpy)	NO_x	0.385 / 0.096	26.79 / 4.02	1.14 / 0.17	0.44 / 0.22
	CO	2.59 / 0.648	15.42 / 2.31	1.05 / 0.16	2.96 / 1.48

[1] Coordinates for UTM Zone 11 referenced to Datum NAD27

6.1.1.2 Good Engineering Practice Analysis

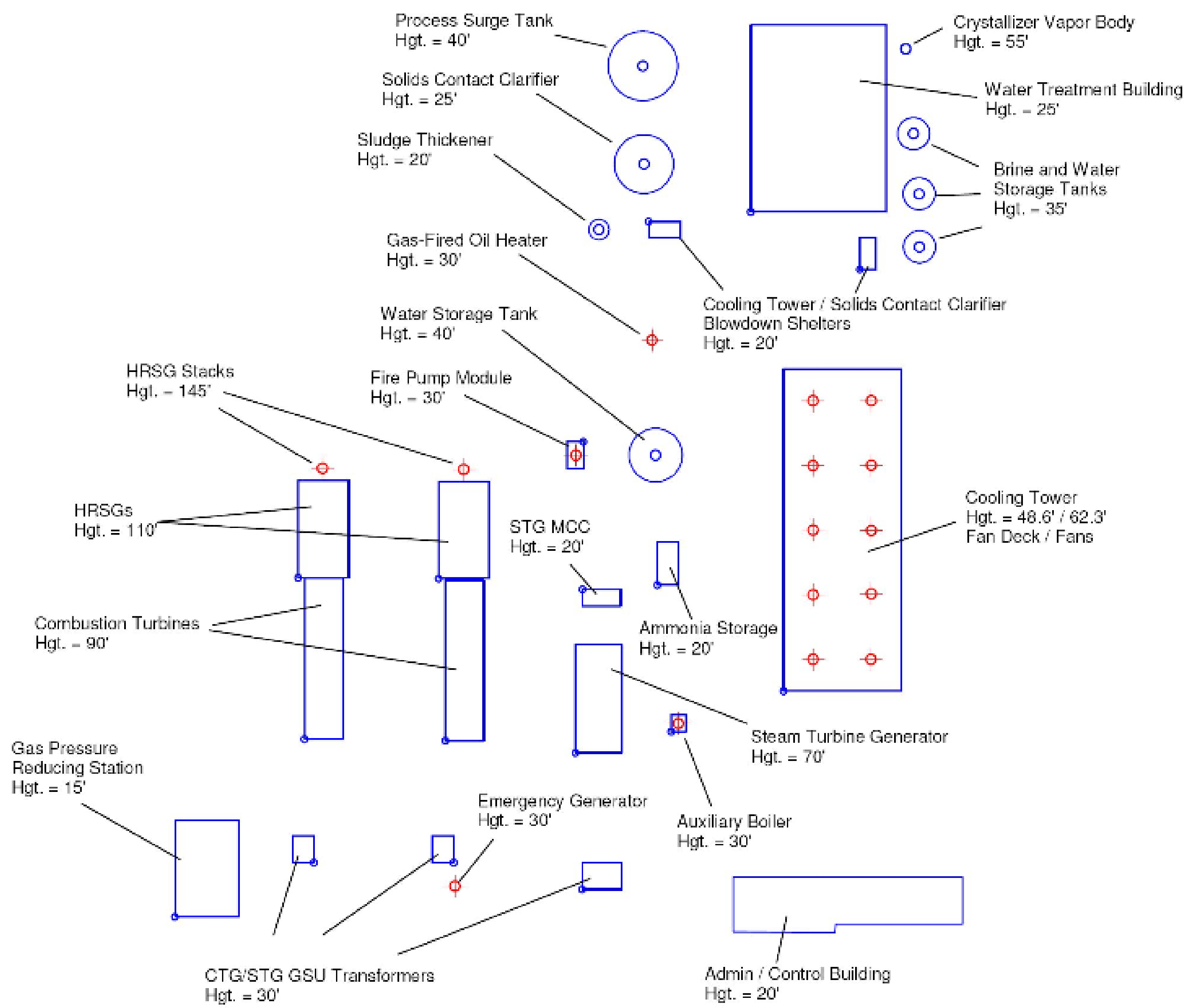
A Good Engineering Practice (GEP) stack height analysis was conducted to evaluate the potential for building downwash. Stacks with heights below GEP are considered to be subject to building downwash and require building dimensions to be input to AERMOD. The GEP stack height analysis was conducted using the EPA Building Profile Input Program (BPIP) (version 04274) that performs the GEP calculation for a multi-building complex on a stack-by-stack basis. The stack locations and buildings included in the GEP analysis are shown in Figure 6-1. A summary of the GEP analysis is provided in Table 6-5. The projected combustion turbine stack height of 145 feet (44 m) is less than GEP, but is more than sufficient to demonstrate compliance with air quality standards as shown below. The stack heights of the ancillary equipment will also be less than their respective GEP formula heights and subject to building downwash. Therefore, building dimensions developed by BPIP for all stacks were input to the dispersion model. The BPIP input and output files are provided on the modeling archive in Appendix D.

Table 6-5
Summary of GEP Analysis

Emission Source	Stack Height (m)	Controlling Buildings or Structures	Building Height (m)	Projected Width (m)	GEP Formula Height (m)
HRSG Stack (West)	44.2	HRSG's #1 and #2	33.53	33.59	83.82
HRSG Stack (East)	44.2	HRSG's #1 and #2	33.53	33.71	83.82
Auxiliary Boiler	9.14	HRSG's #1 and #2	33.53	45.10	83.82
Fire-Water Pump Module	9.14	HRSG's #1 and #2	33.53	33.71	83.82
Gas-Fired HTF Heater	9.14	HRSG's #1 and #2	33.53	46.17	83.82
Emergency Generator	9.15	HRSG #1	33.53	25.36	71.56
Cooling Tower	19.0	HRSG's #1 and #2	33.53	33.59 and 36.13	83.82

6.1.1.3 Ozone Limiting Method

The Ozone Limiting Method (OLM) in AERMOD was used as a refined technique to more accurately model the conversion of NO_x emissions to ambient NO_2 concentrations. The OLM analysis falls under Tier 3 of the U.S. EPA's multi-tiered screening approach for estimating NO_2 sources from point sources as provided in the Guideline on Air Quality Models. In the OLM analysis, 10% of the NO_x emissions from the source are assumed to convert to NO_2 (i.e., fraction associated with thermal conversion) while the remaining fraction of NO_x (90%) is converted based on available ambient ozone (O_3) concentrations. That is, conversion of the remaining 90% of NO_x (to NO_2) is limited based on the availability of ozone and the remaining converted NO_2 is equivalent to the ambient O_3 concentration. These computations are conducted internally in AERMOD on an hourly basis and require representative hourly monitored O_3 that are concurrent to the meteorological data used in the modeling. For this analysis, the 3 concurrent years (2002-2004) of monitored O_3 concentrations from the Victorville Park Avenue monitoring station were used.



Locus Map

Buildings and Sources Used in the GEP Analysis
VV2 Hybrid Power Project

Figure not to scale

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Figure: 6-1

Date: April 2007

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6.1.2 Modeling Results

6.1.2.1 Class II Impacts from Project Normal Operations

The modeling of normal VV2 Project operations using AERMOD was done as a multi-step process. First, the worst-case impacts for the combustion turbines (based on different load and temperatures) were identified. The detailed results for the combustion turbine load analysis are provided in Appendix C.

The NAAQS for NO_2 is an Annual Average, while the NAAQS for CO are short-term, 1- and 8-hour averages. Modeling of NO_2 for annual averages was conducted with the annual average operating scenario for the turbines (100% load / 77°F ambient temperature). Since CO is assessed on a short-term basis, operations at different loads could be worst case. The worst-case load for CO was determined to be 100%.

In the next modeling step, the worst-case combustion turbine operating parameters and emissions were combined with normal operations of the facility ancillary sources. Because the emergency generator and fire pump will not be operated for more than one-hour at a time it was assumed that these two sources will operated only from 8 am to 9 am in order to model the likely worst case meteorological conditions (morning stable layer).

The maximum air quality impacts due to emissions from the Project sources are summarized in Table 6-6. Table 6-6 lists the maximum modeled concentrations for all VV2 Project sources for each year of meteorology. The maxima over the three years modeled is noted and compared to the EPA SILs. As shown in Table 6-6, all maximum modeled pollutant concentrations of NO_2 and CO are less than their respective SIL.

Table 6-6
Maximum Modeled Concentrations for VV2 Project Normal Operations

Pollutant	Averaging Period	Maximum AERMOD Concentration ($\mu g/m^3$)			Overall Maximum ($\mu g/m^3$)	EPA SIL ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)
		2002	2003	2004			
NO_2 [a]	Annual	0.3	0.3	0.3	0.3	1	25
CO	1-hr	215.7	215.8	212.1	215.8	2,000	None
	8-hr	31.0	29.6	31.9	31.9	500	None

a. Modeled NO_2 concentrations as determined with the Ozone Limiting Method.

Since the impacts were below the SILs, no cumulative or NAAQS analysis is required. Although not required, a NAAQS analysis was done and is summarized in Table 6-7. The Project maximum modeled concentrations for NO_2 and CO are summed with ambient background concentrations (from Table 6-1) for comparison to the air standards. As shown in Table 6-7, the total concentrations comprised of maximum modeled plus maximum background are below the NAAQS.

Table 6-7
NAAQS Analysis for Project Normal Operations

Pollutant	Averaging Period	Concentrations ($\mu g/m^3$)			
		AERMOD Result	Ambient Background [b]	Total [c]	NAAQS
NO_2 [a]	Annual	0.3	41	41.3	100
CO	1-hr	215.8	4,485	4,701	40,000
	8-hr	31.9	2,415	2,447	10,000

a. Modeled NO_2 concentrations as determined with the Ozone Limiting Method.
b. Highest value from Table 6-1.
c. Modeled concentration plus ambient background.

6.1.2.2 Impacts from Combustion Turbine Start-up/Shutdown

During startup and shutdown of the combustion turbines, emissions of CO will be higher than normal operations. As such, worst-case startup and shutdown conditions were modeled with AERMOD for comparison to the NAAQS for 1-hour and 8-hour CO. The stack parameters and emissions data required for modeling short-term startup/shutdown are provided in Table 6-8. The stack exhaust parameters correspond to a 20 percent load, assumed to be representative of this operating mode.

Table 6-7
Stack Parameters and Emissions Data for the Combustion Turbines Start-up/Shutdown Modeling

Parameter		Value
Exit Temperature (^oF) [a]		173.5
Exit Velocity (ft/sec) [1]		31.76
Pollutant Emissions Per Combustion Turbine (lb/hr)	NO_x	64.8
	CO	344.1

a. Based on 20% load.

Worst case startup/shutdown emissions for modeling were derived from the emissions data in Appendix C. Cold starts, warm starts, hot starts and shutdowns were considered. Based on this analysis, the worst case or maximum emissions are associated with shutdown events. Because shutdowns only require 0.5 hour, maximum 1 hour emissions are conservatively based on 0.5 hour at the maximum normal emission rate plus 0.5 hour in the shutdown mode as shown below:

- Maximum CO emissions = 0.5 x 14.25 lb/hr + 0.5 x 674 lb/hr = 344.1 lb/hr per turbine

The modeling was conducted for the 3-years of meteorological data and assumed simultaneous operation of all ancillary equipment with the two combustion turbines. The results are summarized in Table 6-9. Ambient concentrations are summed with the maxima modeled over the 3 years for comparison to the NAAQS. The total CO concentrations are below the NAAQS.

Table 6-8
Maximum Modeled CO Concentrations for Project Startup/Shutdown Operations

Pollutant	Averaging Period	AERMOD Concentration (μg/m^3)			Overall Maximum (μg/m^3)	Total Modeled Plus Background	NAAQS (μg/m^3)
		2002	2003	2004			
CO	1-hr	635.7	672.5	658.9	672.5	5,157	40,000
	8-hr	301.0	283.7	238.2	301	2,716	10,000

6.2 PSD Class I Analysis

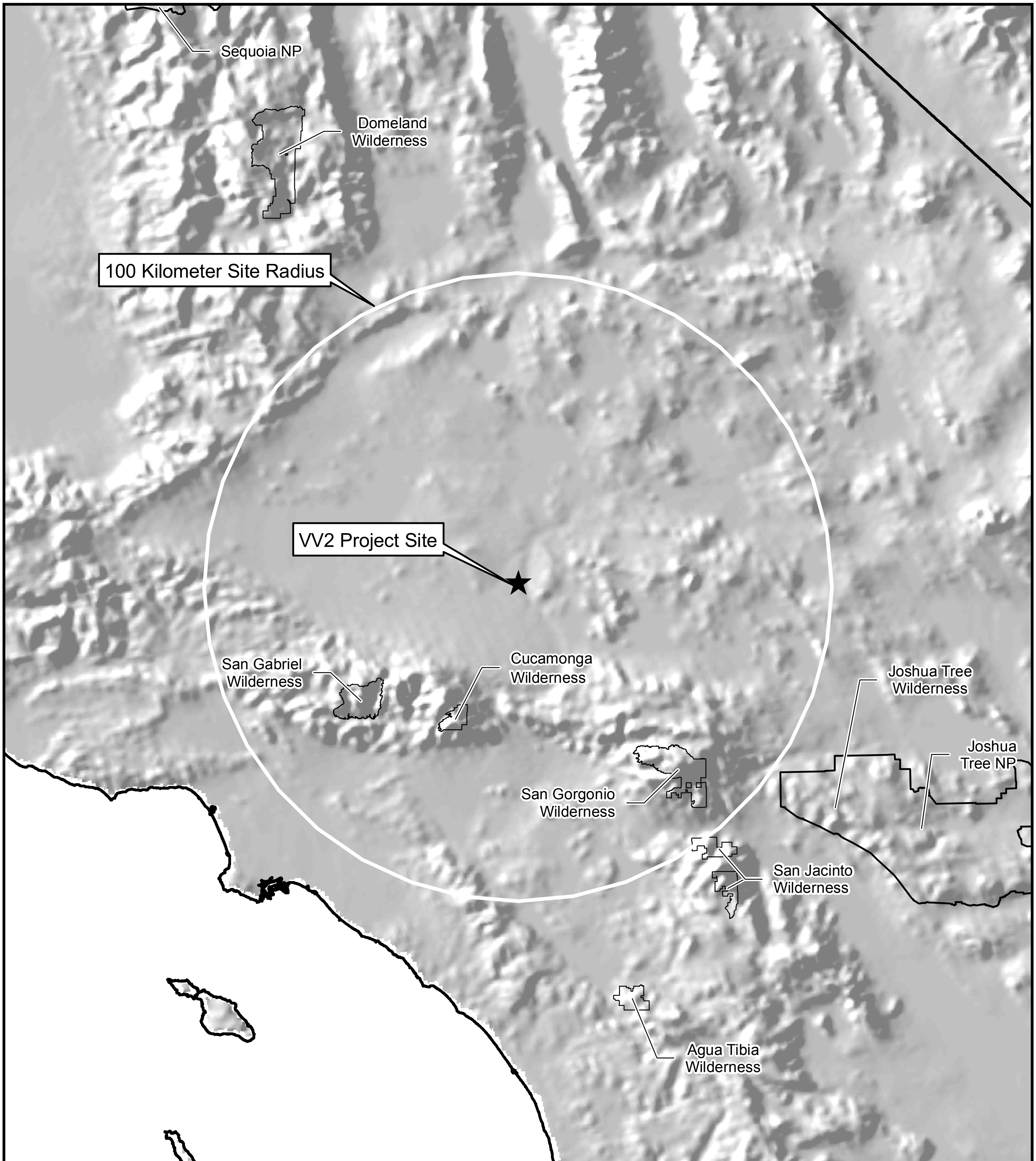
PSD regulations require that facilities within 100 kilometers (km) of a PSD Class I area perform a modeling evaluation of the ambient air quality in terms of Class I PSD Increments and Air Quality Related Values (AQRVs). For the VV2 Project, potential air impacts were addressed at the following Class I areas within 100 km:

- Cucamonga Wilderness Area (WA),
- San Gabriel WA,
- San Gorgonio WA,
- San Jacinto WA, and
- Joshua Tree National Park (NP).

The detailed methodology for the Class I area impact assessment is documented in the modeling protocol, "Class I Area Dispersion Modeling Protocol for the Proposed Victorville 2 Hybrid Power Project. A copy of this protocol was submitted to the CEC, EPA and MDAQMD on January 17, 2007. At EPA's request, a copy of the protocol was also provided to the Federal Land Managers (FLMs) for these areas on January 31, 2007. The National Park Service (NPS) is the FLM for Joshua Tree NP and the U.S. Dept. of Agriculture, Forest Service (USFS) is the FLM for the four Wilderness Areas. On February 1, 2007, the NPS replied "based on the information in the protocol we do not believe the emissions from the proposed Victorville facility will significantly impact resources at Joshua Tree National Park (closest NPS air quality Class I area). Therefore, we will not be providing any comments regarding the protocol." (Morse, 2007) The USFS provided a copy of their draft FLM modeling guidance document (Gebhart, 2005).

Figure 6-2 shows the location of the VV2 Project relative to the nearest PSD Class I areas. Since Joshua Tree NP is the closest National Park Service (NPS) Class I area and it is just on the edge of the 100-km extent from the VV2 Project, it was also included in the Class I impacts analysis.

Since the VV2 Project is located in a designated non-attainment area for PM10, and is not a significant source for SO_2 or H_2SO_4, a Class I increment analysis was conducted only for NO_2 at the Class I areas. Additionally since the VV2 Project is not a significant source for SO_2 or H_2SO_4, a deposition analysis was conducted only for nitrogen compounds which consider primary emissions of NO_X and conversion to nitrate and nitric acid. However, gas turbine emissions of SO_2, H_2SO_4, NO_X, and PM10 were all included in the regional haze analysis for the Class I areas noted above.



Locus Map

Location of Proposed Project Site in Relation to Nearby PSD Class I Areas VV2 Hybrid Power Project

Scale: 1:1,750,000

0 20 40 60 80 100 Miles

Inland Energy, Inc.

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Date: April 2007

Figure: 6-2

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6.2.1 PSD Class I Area CALPUFF Analyses

A refined modeling for assessment of PSD Class I increment consumption, regional haze and acid deposition was conducted with the CALPUFF model (Version 5.754) and utilized detailed meteorological data prepared with CALMET, the CALPUFF meteorological pre-processor. The modeling approach is based on requirements outlined in the IWAQM Phase II report (EPA Report EPA-454/R-98-019, 1998; found at http://www.epa.gov/scram001) as well as the Federal Land Managers' Air Quality Related Values Workgroup Phase I Report that was published in December 2000. This document can be found at http://www2.nature.nps.gov/ard/flagfree/index.htm). These guidance documents are provided for suggested modeling approaches by EPA and the FLMs.

6.2.1.1 Class I Area Increment Analysis

The Class I increment modeling results for all areas are summarized in Table 6-10. The maximum annual NO_2 concentrations for each area are below the Class I SIL and therefore also well below the Class I PSD increments.

Table 6-9
Class I Area NO_2 PSD Increment CALPUFF Modeling Result

Class I Area	Averaging Period	Maximum Modeled Concentrations (µg/m^3)			Class I SIL[1] (µg/m^3)	PSD Class I Increment (µg/m^3)
		2001	2002	2003		
Cucamonga WA	Annual	3.29E-03	1.92E-03	2.05E-03	0.1	2.5
Joshua Tree NP	Annual	1.27E-03	9.92E-04	9.32E-04	0.1	2.5
San Gabriel WA	Annual	2.94E-03	9.95E-04	3.12E-03	0.1	2.5
San Gorgonio WA	Annual	8.17E-04	1.23E-04	5.21E-04	0.1	2.5
San Jacinto WA	Annual	3.67E-04	6.85E-05	1.77E-04	0.1	2.5

[1] EPA proposed NSR Reform, FR 7/23/96.

6.2.1.2 Class I Area Regional Haze Analysis

The Class I regional haze modeling results for all areas are summarized in Table 6-11 for the three-years modeled. When a project-related change in extinction is less than five percent of the background extinction, then the project's regional haze impact is defined by EPA to be insignificant and no further modeling is required to demonstrate no adverse impact. As shown in Table 6-11, the maximum modeled change in extinction (Δ B_{ext}) for all years is less than five percent.

Table 6-10
Class I Area Regional Haze CALPUFF Modeling Results

Class I Area	Maximum % Δ B_{ext}			Significance Threshold (Percent Change in Extinction Coefficient)
	2001	2002	2003	
Cucamonga WA	3.80	2.39	3.14	5%
Joshua Tree NP	1.20	1.16	0.95	5%
San Gabriel WA	2.30	2.48	3.56	5%
San Gorgonio WA	1.05	0.78	1.98	5%
San Jacinto WA	0.58	0.56	0.75	5%

6.2.1.3 Class I Area Deposition Analysis

The Class I Area deposition modeling results for all areas are summarized in Table 6-12 for the three-years modeled. The maximum modeled deposition rates for all years modeled are below the Class I Area Deposition Analysis Thresholds.

Table 6-11
Class I Area Nitrogen Deposition CALPUFF Modeling Results

Class I Area	Averaging Period	Maximum Modeled Deposition Results (kg/ha/yr)			Class I Area Nitrogen Deposition Analysis Threshold (kg/ha/yr)
		2001	2002	2003	
Cucamonga WA	Annual	9.96E-04	1.15E-03	6.92E-04	0.005
Joshua Tree NP	Annual	3.23E-04	2.49E-04	2.51E-04	0.005
San Gabriel WA	Annual	1.44E-03	8.57E-04	1.38E-03	0.005
San Gorgonio WA	Annual	3.88E-04	1.99E-04	2.60E-04	0.005
San Jacinto WA	Annual	1.51E-04	7.92E-05	8.60E-05	0.005

6.2.2 VISCREEN Plume Blight Impact Analysis

PSD regulations require an analysis of visibility impairment (i.e., plume blight) at Class I areas within 50 km of a proposed PSD project. Parts of Cucamonga Wilderness Area are located within 50 km of the VV2 Project, therefore in addition to regional haze assessed with CALPUFF, potential VV2 Project visible plume impacts were also addressed for this Class I area.

The plume visibility analysis was conducted with the most current version of EPA's screening model VISCREEN to determine if Project emissions will impair visibility at the Cucamonga WA. VISCREEN was applied with the guidance provided in EPA's Workbook for Plume Visual Impact

Screening and Analysis (Revised, 1992) ("Workbook"). As such, the VISCREEN model was applied to estimate two visual impact parameters, plume perceptibility (ΔE) and plume contrast (Cp). Screening-level guidance indicates that values above 2.0 for ΔE and +/- 0.05 for Cp are considered perceptible. The Workbook offers two levels of analysis. Level 1 screening analysis is the most simplified and conservative approach employing default meteorological data with no site specific conditions. Level 2 analyses takes into account representative meteorological data and site specific conditions such as complex terrain. Initially, the Level 1 analysis was conducted and indicated ΔE and Cp values above the screening thresholds. Therefore, a Level 2 analysis was conducted.

A Level 2 analysis was conducted with the same three-years of meteorological data used in the Class II air quality analysis. The terrain elevation differences between the facility location of more than 600 meters is based on an elevation of the plant site (854 meters above mean sea level [amsl]) and elevation of the Cucamonga WA (1500 - 2600 meters amsl; from receptor elevations provided by NPS.

The source data required by VISCREEN are total NO_x emissions (31.2 lb/hr) and particulate emissions (36.0 lb/hr) for the combustion turbines. The closest distance from the Project to the Cucamonga WA is 40 kilometers. In addition, the 22.5° wind direction sector that would transport emissions from the Project toward the Cucamonga WA located to the south-southwest of the Project location is 11.25° – 33.75°. Based on this information, and the three years of meteorological data, a table of joint frequency of occurrence of wind speed, wind direction, and stability class was developed as outlined in the Workbook. The dispersion conditions, defined by wind speed and stability class, were ranked by evaluating the product of $\sigma_y\sigma_z u$ where σ_y and σ_z are the Pasquill-Gifford horizontal and vertical diffusion coefficients for the given stability class and downwind distance (i.e., 40 km), and u is the wind speed. The dispersion conditions were then ranked in ascending order according to the value of $\sigma_y\sigma_z u$ as shown in Table 6-13.

According to the Workbook, VISCREEN is to be applied with the worst-case meteorological conditions that have a $\sigma_y\sigma_z u$ product with a cumulative probability of 1 percent. That is, the dispersion condition is selected such that the sum of all frequencies of occurrence of conditions worse than this condition totals 1 percent. Note that as is recommended by the Workbook, dispersion conditions that result in greater than 12 hours of plume transport time are discounted from the analysis, since it is unlikely that steady-state plume conditions will persist for more than 12 hours.

According to Table 6-13, the worst-case dispersion conditions with cumulative frequency of 1 percent are D stability, 3 m/sec and occur during daytime hours between 12:00 pm and 6:00 pm (i.e., 1200-1800). Therefore, VISCREEN was applied with C stability, 3 m/sec to account for the complex terrain. As recommended by the FLAG guidance, a visual range of 246 kilometers was used.

The VISCREEN results are summarized in Table 6-14. VISCREEN provides results of plume perceptibility (ΔE) and plume contrast (C_p) for both sky and terrain backgrounds. The results are below the screening criteria thresholds and therefore indicate that the plume would not be perceptible against a sky or terrain background.

Table 6-12: Dispersion Condition Frequency Analysis

Dispersion Condition		$\sigma_y \sigma_z u$	Transport Time	Frequency By Time of Day				Cumulative Frequency By Time of Day			
Stability Class	Wind Speed (m/sec)			0-6	6-12	12-18	18-24	0-6	6-12	12-18	18-24
F	1	68,547	22	0.152	0.000	0.015	0.274	0.000	0.000	0.000	0.000
F	2	137,093	7	0.015	0.000	0.046	0.228	0.015	0.000	0.046	0.228
E	1	196,008	22	0.046	0.015	0.030	0.091	0.015	0.000	0.046	0.228
F	3	205,640	4	0.015	0.015	0.061	0.182	0.030	0.015	0.106	0.411
E	2	392,015	7	0.046	0.030	0.061	0.061	0.076	0.046	0.167	0.471
D	1	536,875	22	0.091	0.228	0.106	0.000	0.076	0.046	0.167	0.471
E	3	588,023	4	0.000	0.000	0.213	0.182	0.076	0.046	0.380	0.654
E	4	784,030	3	0.000	0.015	0.274	0.106	0.076	0.061	0.654	0.760
E	5	980,038	2	0.000	0.000	0.122	0.061	0.076	0.061	0.776	0.821
D	2	1,073,749	7	0.000	0.046	0.122	0.030	0.076	0.106	0.897	0.852
D	3	1,610,624	4	0.000	0.030	0.274	0.015	0.076	0.137	1.171	0.867
D	4	2,147,498	3	0.000	0.061	0.456	0.091	0.076	0.198	1.627	0.958
D	5	2,684,373	2	0.046	0.319	1.414	0.076	0.122	0.517	3.041	1.034
D	6	3,221,247	2	0.015	0.106	0.502	0.030	0.137	0.623	3.543	1.064
D	7	3,758,122	2	0.015	0.152	0.182	0.015	0.152	0.776	3.726	1.080
D	8	4,294,997	1	0.015	0.000	0.030	0.000	0.167	0.776	3.756	1.080

Table 6-13
VISCREEN Model Results

Background	Distance	Plume Perceptibility (ΔE)		Plume Contrast (C_p)	
		VISCREEN	Criteria	VISCREEN	Criteria
Sky	40	0.066	2.00	0.001	0.05
Terrain	40	0.168	2.00	0.001	0.05

6.3 Other Related Analyses

PSD regulations also require that projects conduct analyses to determine the impacts on vegetation and soils, and also from secondary emissions due to growth in the area.

6.3.1 Vegetation and Soils

The VV2 Project site is in an area consisting of desert and desert shrub-land. Criteria for evaluating impacts on soils and vegetation are provided in EPA's A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals (EPA 1980). Table 6-15 lists the EPA suggested criteria for the gaseous pollutants emitted directly from the proposed facility. These criteria are established for sensitive vegetation and crops exposed to the effects of the gaseous pollutants through direct exposure. Adverse impacts on soil systems result more readily from the secondary effects of these pollutants' impacts on the stability of the soil system. These impacts could include increased soil temperature and moisture stress and/or increased runoff and erosion resulting from damage to vegetative cover. In Table 6-15, the total modeled air concentrations for the proposed facility plus ambient background concentrations are compared to these criteria to evaluate impacts on both soils and vegetation. All total concentrations are well below all of the criteria. Therefore, the potential for adverse impacts to either soils or vegetation is negligible.

Table 6-14
Soils and Vegetation Analysis

Pollutant	Averaging Time	Modeled Project Impacts ($\mu g/m^3$)	Ambient Background ($\mu g/m^3$)	Total ($\mu g/m^3$)	Minimum Impact Level for Affects On Sensitive Plants ($\mu g/m^3$)
NO_2	4 hour	239.9	169	409	3,760
	8 hour	239.9	169	409	3,760
	1 month	239.9	169	409	564
	Annual	0.3	41	41.3	94
CO	1 week	31.9	2,415	2,447	1,800,000

6.3.2 Growth Analysis

PSD requires an assessment of the secondary impacts from applicable projects. There will be minimal associated growth expected during VV2 Project construction due to the relatively short-term (27 months) duration and the existence of a large construction labor force in the southern California region. Additionally, no long-term growth (i.e., general commercial, residential, industrial or other secondary growth in the area) is expected during Project operations due to the small labor force (36 employees) that will be required to operate this hybrid power plant. Therefore, no analysis of secondary impacts from associated growth is needed for this Project.

7.0 References

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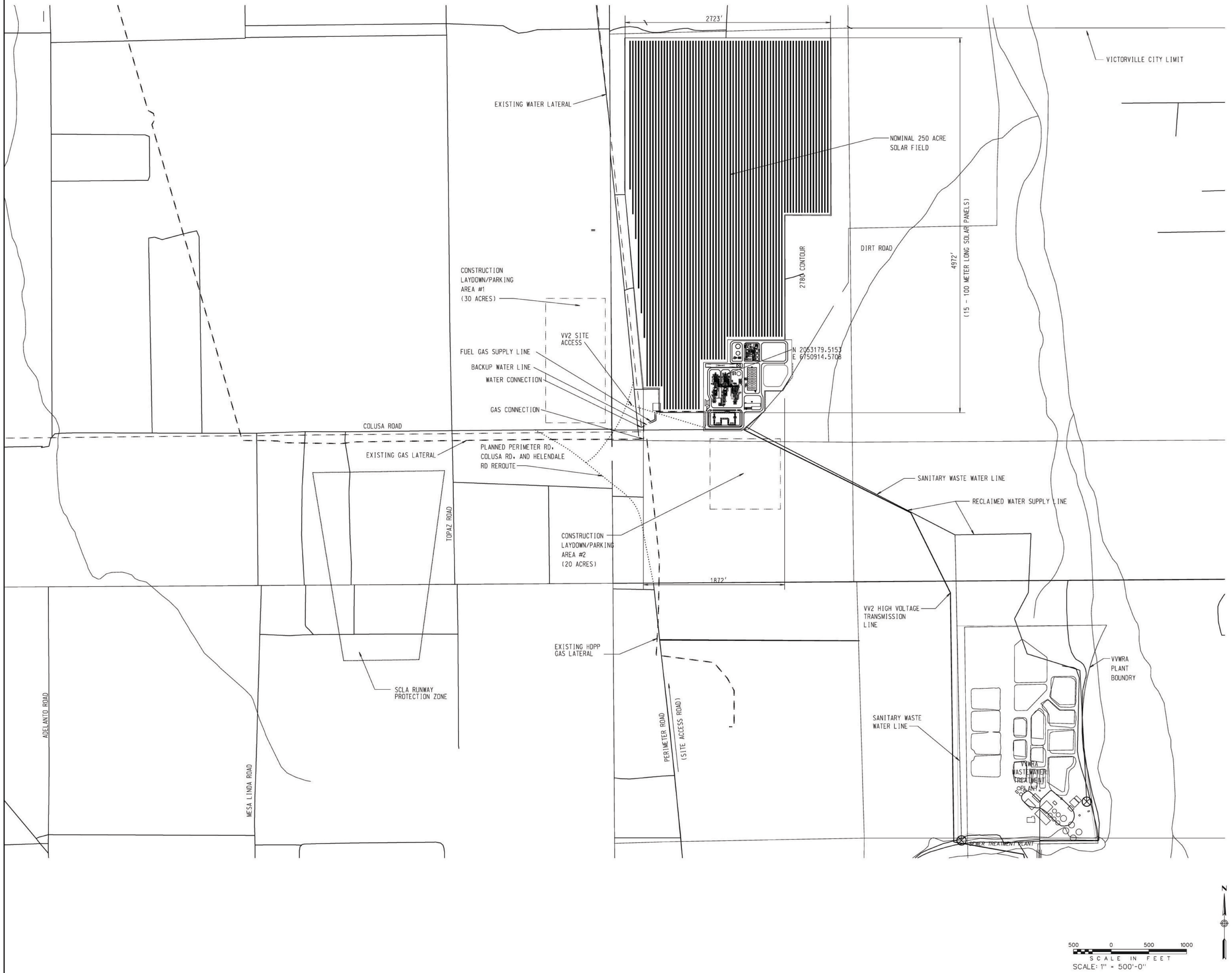
Appendix A

Facility Diagrams



NOTES:

1. SANITARY WASTE WATER LINE, RECLAIM WATER SUPPLY LINE, FUEL GAS LINE, AND BACK-UP WASTE SUPPLY LINE WILL BE AT BURIAL DEPTH OF 3' TO 6' EXCEPT AT LOCATIONS WHERE THE LINES ARE UNDERNEATH, ROADS, RAILROAD TRACK, AND OTHER FEATURES WHERE SAFTY GUIDLINES, REGULATIONS, OR GOOD ENGINEERING PRACTICE REQUIRES A DIFFERENT DEPTH. AT THESE LOCATIONS THE BURIAL DEPTH IS NOT EXPECTED TO EXCEED 10'-0".

2. VVWRA PLANT BORDERS AND EAST BORDERS ARE APPROXIMATE.

LEGEND:

FUEL GAS SUPPLY LINE

WATER LINE

VV2 HIGH VOLTAGE TRANSMISSION LINE

SANITARY WASTE WATER LINE

PROPOSED ROAD

EXISTING ROAD

RECLAIMED WATER SUPPLY LINE

⊗ = OFFSITE TIE-IN LOCATION

- PRELIMINARY -
NOT FOR CONSTRUCTION

CONFIDENTIAL

REV	DESCRIPTION	DWN	CHK	APP	DATE
N	REVISED PER INLAND'S 02-09-07 COMMENTS	DAD	RRT	CKB	02-09-07
M	REVISED PER INLAND'S 01-31-06 COMMENTS	DAD	RRT	CKB	02-06-07
L	ADDED GAS, WATER SANITARY & RECLAIMED WATER LINES	DAD	RRT	CKB	12-15-06
K	REVISED GAS AND WATER LATERALS	RWF	RRT	CKB	09-25-06
J	REVISED GAS AND WATER LATERALS	SRH	RRT	CKB	09-12-06
I	REVISED GAS AND WATER LATERALS	DNL	RRT	CKB	08-22-06
H	ADDED SITE COORDINATES	DNL	RRT	CKB	07-26-06
G	ADDED GEO SPACIAL REFERENCE	DNL	RRT	CKB	07-11-06
F	UPDATED LINEARS PER SURVEY GPS MEASUREMENTS	CED	RSG	CKB	04-28-06
E	DELETED LEACHATE FIELD, ADDED SANITARY WASTE WATER LINE TO EXIST TREATMENT PLANT	CED	RSG	CKB	03-17-06
D	REVISED SOLAR ARRAY AND POWER BLOCK LOCATION PER PROPOSED RAILROAD AND ROAD PLAN	CED	RSG	CKB	11-03-05
C	DELETED HIGH VOLTAGE ALT 2; REVISED INTERSECTION OF ROADS PER CITY, CONSTRUCTION LAYDOWN	CED	RSG	CKB	10-19-05
B	PRELIMINARY - RELOCATED SOLAR FIELD AND POWER BLOCK	CED	RSG	CKB	09-28-05
A	PRELIMINARY	EGP	RSG	CKB	04-15-05

KIEWIT INDUSTRIAL CO.
A Kiewit Company

CITY OF VICTORVILLE

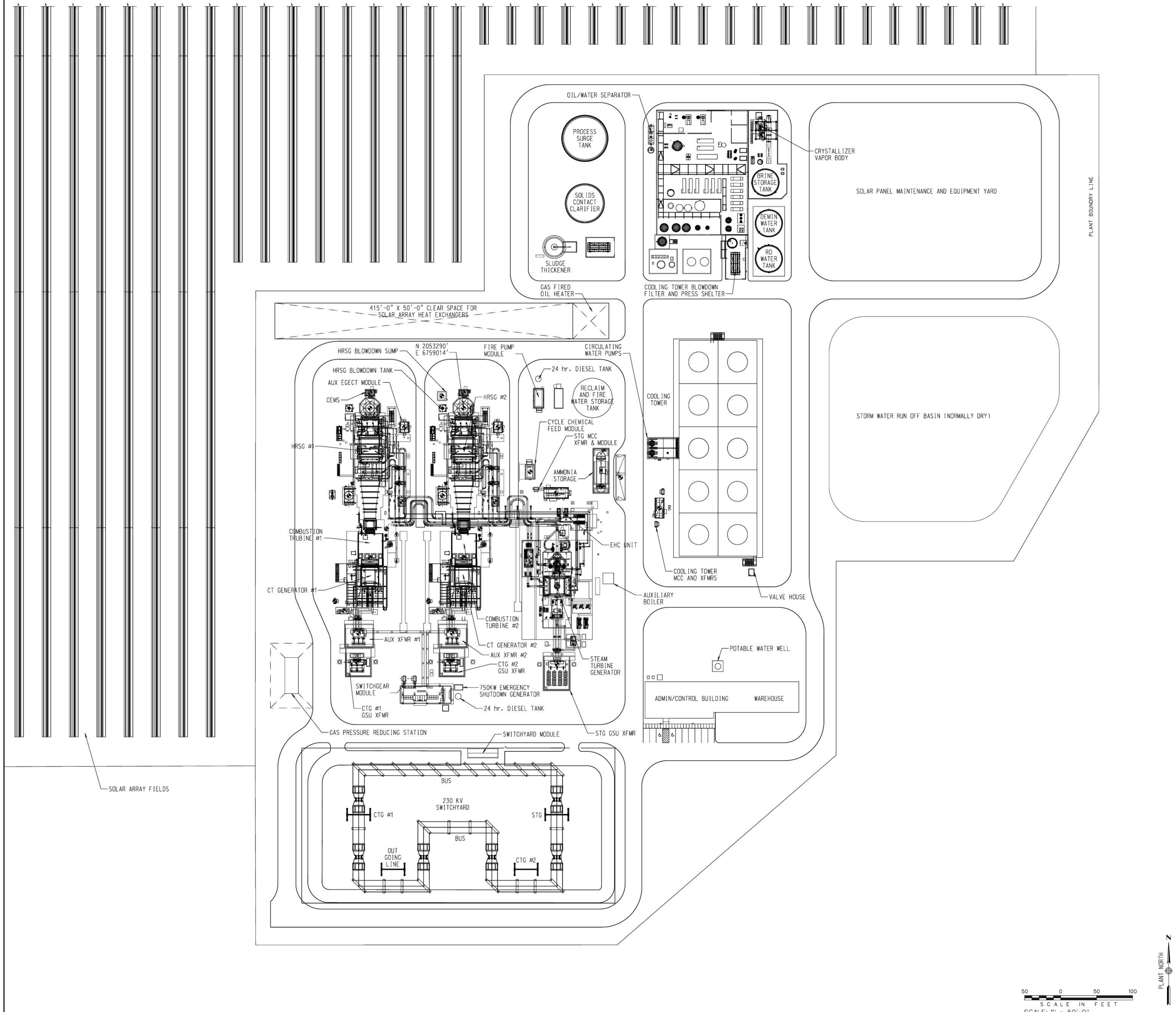
VICTORVILLE 2 HYBRID
POWER PROJECT - SITE PLAN

Bibb and associates
8455 Lenexa Drive
Lenexa, Kansas 66214

Appendix A

	by	date
DESIGNED	RSG	04-15-05
DRAWN	EGP	04-15-05
CHECKED	---	----
APPROVED	---	----

DRAWING NUMBER
2005-038-SP-001



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REV	DESCRIPTION	DWN	CHK	APP	DATE
P	REVISED PER INLAND'S 01-31-06 COMMENTS	DAD	RRT	CKB	02-06-07
N	REVISED SOLAR PANEL YARD AND BASIN	DAD	RRT	CKB	11-29-06
M	REVISED PLANT BOUNDRY AND ADDED BASIN	DAD	RRT	CKB	11-27-06
L	REVISED WATER TREATMENT AREA	MRF	RRT	CKB	11-22-06
K	REVISED ELECTRICAL EQUIPMENT	DAD	RRT	CKB	11-09-06
J	ADDED SWITCHYARD	DAD	RRT	CKB	11-03-06
I	REVISED EQUIPMENT ARRANGEMENT	RWF	RRT	CKB	09-25-06
H	REVISED EQUIPMENT ARRANGEMENT	DNL	RRT	CKB	09-12-06
G	REVISED EQUIPMENT ARRANGEMENT	DNL	RRT	CKB	08-22-06
F	REVISED COOLING TOWER AND REARRANGED EQUIPMENT	DNL	RRT	CKB	08-10-06
E	ADDED SITE COORDINATES	DNL	RRT	CKB	07-26-06
D	ADDED ADDITIONAL EQUIPMENT	DNL	RRT	CKB	07-21-06
C	ADDED GEO SPACIAL REFERENCE	DNL	RRT	CKB	07-11-06
B	ADDED NEW WELL	DZ	RSG	CKB	OPEN
A	PRELIMINARY	CED	RSG	CKB	09-28-05

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CITY OF VICTORVILLE

VICTORVILLE 2 HYBRID
POWER PROJECT - POWER BLOCK PLOT PLAN

Bibb and associates

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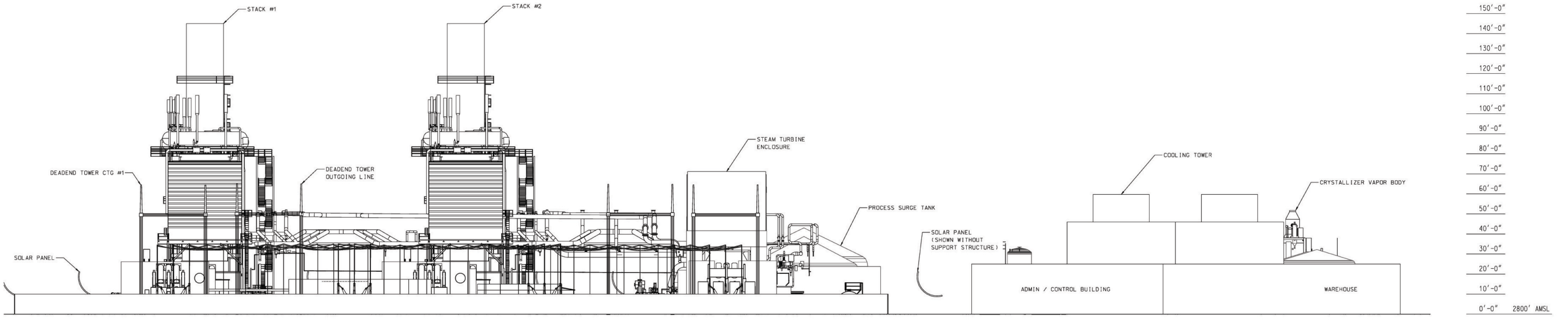
Lenexa, Kansas 66214

Appendix A

	by	date
DESIGNED	CKB	09-21-05
DRAWN	CED	09-23-05
CHECKED		
APPROVED		

DRAWING NUMBER
2005-038-PP-001



ELEVATION LOOKING NORTH

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REV	DESCRIPTION	DWN	CHK	APP	DATE
B	REVISED PER INLAND'S 01-31-06 COMMENTS	DAD	RPT	CKB	02-06-07
A	ISSUED FOR REVIEW	DAD	RPT	CKB	12-01-06

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CITY OF VICTORVILLE

VICTORVILLE 2 HYBRID
POWER PROJECT - ELEVATION

Bibb and associates
8455 Lenexa Drive
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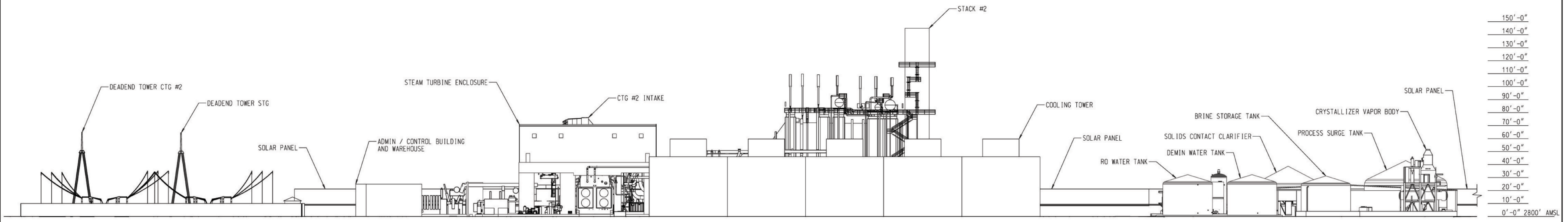
Appendix A

	by	date
DESIGNED	DAD	11-30-06
DRAWN	DAD	11-30-06
CHECKED		
APPROVED		

DRAWING NUMBER
2005-038-MD-001

20 0 20 40
SCALE IN FEET
SCALE: 1" = 20'-0"



ELEVATION LOOKING WEST

50 0 50 100
SCALE IN FEET
SCALE: 1" = 50'-0"

- PRELIMINARY -
NOT FOR CONSTRUCTION

CONFIDENTIAL

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REV	DESCRIPTION	DWN	CHK	APP	DATE
B	REVISED PER INLAND'S 01-31-06 COMMENTS	DAD	RRT	CKB	02-06-07
A	ISSUED FOR REVIEW	DAD	RRT	CKB	12-01-06

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CITY OF VICTORVILLE

VICTORVILLE 2 HYBRID
POWER PROJECT - ELEVATION

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Appendix A

	by	date
DESIGNED	DAD	11-30-06
DRAWN	DAD	11-30-06
CHECKED		
APPROVED		

DRAWING NUMBER
2005-038-MD-002

Appendix B

Control Technology Listings

Table B-1
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for NO_x

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPU TUNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	NV	2 - NATURAL GAS FIRED COMBINED CYCLE COMBUSTION TURBINE GENERATORS WITH HRSG"S AND DUCT BURNERS. 2 - NATURAL GAS FIRED FUEL PREHEATERS. 1 - NATURAL GAS FIRED AUXILIARY BOILER	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	15.21	NATURAL GAS	306	MW	2	PPM @ 15% O2	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	NV	2 - NATURAL GAS FIRED COMBINED CYCLE COMBUSTION TURBINE GENERATORS WITH HRSG"S AND DUCT BURNERS. 2 - NATURAL GAS FIRED FUEL PREHEATERS. 1 - NATURAL GAS FIRED AUXILIARY BOILER	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	15.21	NATURAL GAS	306	MW	2	PPM @ 15% O2	
*OR-0041	WANAPA ENERGY CENTER	DIAMOND WANAPA I, L.P.	OR	A 1,200 MW NATURAL GAS-FIRED COMBINED CYCLE COMBUSTION TURBINE PROJECT EMPLOYING A WATER-COOLED STEAM CONDENSING SYSTEM. FOUR COMBUSTION TURBINES, FOUR HEAT RECOVERY STEAM GENERATORS, TWO STEAM TURBINES, AND TWO COOLING TOWERS EMPLOYED.	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	2384	MMBTU/H	2	PPM @ 15% O2	
FL-0263	FPL TURKEY POINT POWER PLANT	FLORIDA POWER AND LIGHT	FL	RESPECTIVELY."	170 MW COMBUSTION TURBINE, 4 UNITS	15.21	NATURAL GAS	170	MW	2	PPM @ 15 % O2	
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	AZ	COMBINED CYCLE GAS-FIRED ELECTRICITY GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	15.21	NATURAL GAS	170	MW	2	PPM AT 15% O2	
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	AZ	COMBINED CYCLE GAS-FIRED ELECTRICITY GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	15.21	NATURAL GAS	180	MW	2	PPM @ 15% O2	
VA-0291	CPV WARREN LLC	CPV WARREN LLC	VA	COMBINED CYCLE POWER GENERATION	TURBINE, COMBINED CYCLE (2)	15.21	NATURAL GAS	1717	mmbtu/h	2	PPM @ 15% O2	
NV-0037	COPPER MOUNTAIN POWER	SEMPRA ENERGY RESOURCES	NV	A 600 MW COMBINED CYCLE ELECTRICAL GENERATION FACILITY CONSISTING OF TWO COMBUSTION TURBINE GENERATORS WITH HEAT RECOVERY STEAM GENERATORS, ONE STEAM TURBINE GENERATOR, AND ONE AUXILIARY BOILER.	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	15.21	NATURAL GAS	600	MW	2	PPM @ 15% O2	3 hr
NV-0038	IVANPAH ENERGY CENTER, L.P.	IVANPAH ENERGY CENTER, L.P.	NV	A 500 MW ELECTRICAL GENERATING PLANT CONSISTING OF TWO COMBUSTION TURBINE GENERATORS, TWO HEAT RECOVERY STEAM GENERATORS, ONE STEAM TURBINE GENERATOR. THE PROPOSED PLANT IS SURROUNDED BY UNOCCUPIED LAND FOR A DISTANCE OF AT LEAST TWO MILES IN ALL DIRECTIONS. THE UN-IMPROVED ACCESS ROAD TO THE PROPOSED PLANT SITE IS ABOUT 1.6 MILES IN LENGTH.	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	15.21	NATURAL GAS	500	MW	2	PPM@ 15% O2	1 hr
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	AZ	POWER PLANT	TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	NATURAL GAS	325	MW	2	PPM @ 15% O2	
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	AZ	POWER PLANT	TURBINE, COMBINED CYCLE	15.21	NATURAL GAS	325	MW	2	PPM @ 15% O2	
*AZ-0049	LA PAZ GENERATING FACILITY	ALLEGHENY ENERGY SUPPLY LLC	AZ	NATURAL GAS FIRED, COMBINED CYCLE GENERATING STATION	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	15.21	NATURAL GAS	1040	MW	2	PPM @ 15 O2	3 hr
CA-0997	SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO MUNICIPAL UTILITY DISTRICT	CA	COMBUSTION GAS TURBINE GE 7FA	GAS TURBINES, (2)	15.21	NATURAL GAS	1611	MMBTU/H	2	PPM @ 15% O2	

Table B-1
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for NO_x

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPU TUNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
CA-1096	VERNON CITY LIGHT & POWER	VERNON CITY LIGHT & POWER	CA		GAS TURBINE: COMBINED CYCLE < 50 MW	15.21	NATURAL GAS	43	MW GAS TURBINE, 55 MW STEAM TURBINE	2	PPM @ 15% O2	
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	MAGNOLIA POWER PROJECT, SCPPA	CA		GAS TURBINE: COMBINED CYCLE >= 50 MW	15.21	NATURAL GAS	181	NET MW (GAS TURBINE W/STEAM INJECTIO N)	2	PPM @ 15% O2	3 hr
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	SUMAS ENERGY 2 GENERATION FACILITY	WA		TURBINES, COMBINED CYCLE, (2)	15.21	NATURAL GAS	660	MW	2	PPM @ 15% O2	
AZ-0039	SALT RIVER PROJECT/SANTAN GEN. PLANT	SALT RIVER PROJECT/SANTA N GEN. PLANT	AZ	POWER PLANT	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	NATURAL GAS	175	MW	2	PPM @ 15% O2	
not listed	ROSEVILLE ENERGY PARK	ROSEVILLE ELECTRIC	CA	160 MW, NATURAL GAS-FIRED, COMBINED-CYCLE GENERATING FACILITY LOCATED WEST OF DOWNTOWN ROSEVILLE, IN PLACER COUNTY. IT WILL HAVE TWO GE LM6000 PC SPRINT OR ALSTOM GTX100 CTGs, EQUIPPED WITH WATER INJECTION (LM6000) OR DRY LOW-NOx COMBUSTERS (GTX100), TWO HRSGs WITH DUCT BURNERS, ONE STEAM TURBINE, CONDENSERS AND A MECHANICAL DRAFT COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	160	MW	2	PPMVD	1 hr
not listed	EL CENTRO UNIT 3 REPOWER PROJECT	IMPERIAL IRRIGATION DISTRICT	CA	128 MW, NATURAL GAS-FIRED COMBINED-CYCLE GENERATING FACILITY WITHIN CURRENT EL CENTRO GENERATING STATION, IN IMPERIAL COUNTY. IT WILL ADD A GE 7EA CTG WITH DRY LOW NOX COMBUSTERS AND ONE HRSG WITH DUCT BURNER TO EXISTING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	128	MW	2	PPMVD	1 hr
not listed	BLYTHE ENERGY PROJECT, PHASE II	CAITHNESS BLYTHE II, LLC	CA	520 MW NATURAL GAS-FIRED COMBINED-CYCLE GENERATING FACILITY ADJACENT TO BLYTHE ENERGY PROJECT PHASE I. IT WILL HAVE TWO SEIMENS WESTINGHOUSE CGTS WITH DRY LOW-NOX COMBUSTERS, TWO HRSGs WITH DUCT BURNERS, ONE STEAM TURBINE, CONDENERS AND A COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	520	MW	2	PPMVD	1 hr
CEC DECISION PENDING	LOS ESTEROS CRITICAL ENERGY FACILITY, PHASE II	LOS ESTEROS CRITICAL ENERGY FACILITY, LLC	CA	CONVERSION OF EXISTING 180 MW SIMPLE-CYCLE POWER PLANT TO A 320 MW COMBINED-CYCLE PLANT WITH ADDITION OF FOUR HRSGs WITH DUCT BURNERS, STEAM TURBINE, CONDENSERS AND A COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	320	MW	2	PPMVD	1 hr
CEC DECISION PENDING	SOUTH BAY REPLACEMENT PROJECT	LSP SOUTH BAY, LLC	CA	REPLACEMENT OF EXISTING FACILITY IN CHULA VISTA IN SAN DIEGO COUNTY WITH A 620 MW NATURAL GAS-FIRED COMBINED-CYCLE PLANT WITH TWO CTGs, TWO HRSGs AND DUCT BURNERS AND STEAM TURBINE	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	620	MW	2	PPMVD	1 hr
UT-0066	CURRANT CREEK	PACIFICORP	UT	POWER GENERATION PLANT WITH TWO NATURAL GAS COMBINED CYCLE TURBINES	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS	15.21	NATURAL GAS			2.25	PPM @ 15% O2	3 hr
FL-0265	HINES POWER BLOCK 4	PROGRESS ENERGY	FL	COMBINED CYCLE POWER PLANT. THIS IS THE 4TH BLOCK OF POWER ADDED, MAKING THE TOTAL GENERATING CAPACITY OF THE FACILITY APPROXIMATELY 2090 MW.	COMBINED CYCLE TURBINE	15.21	NATURAL GAS	530	MW	2.5	PPM @ 15% O2	
MI-0366	BERRIEN ENERGY, LLC	BERRIEN ENERGY, LLC	MI	ELECTRIC POWER GENERATING FACILITY.	3 COMBUSTION TURBINES AND DUCT BURNERS	15.21	NATURAL GAS	1584	MMBTU/H	2.5	PPM @ 15% O2	
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	VA	POWER PLANT	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	NATURAL GAS	170	MW	2.5	PPM @ 15% O2	

Table B-1
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for NO_x

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPU TUNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	VA	POWER PLANT	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	NATURAL GAS	170	MW	2.5	PPM @ 15% O2	
OR-0039	COB ENERGY FACILITY, LLC	Peoples Energy Resources	OR	POWER GENERATION FACILITY	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	15.21	NATURAL GAS	1150	MW	2.5	PPM @ 15% O2	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	VA	POWER GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	NATURAL GAS	1973	MMBTU/H	2.5	PPM @ 15% O2	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	VA	POWER GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	15.21	NATURAL GAS	1973	MMBTU/H	2.5	PPM @ 15% O2	
FL-0256	HINES ENERGY COMPLEX, POWER BLOCK 3	PROGRESS ENERGY FLORIDA	FL	POWER PLANT	COMBUSTION TURBINES, COMBINED CYCLE, NATURAL GAS,2	15.21	NATURAL GAS	1830	MMBTU/H	2.5	PPMVD @15% O2	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	SAVANNAH ELECTRIC AND POWER CO	GA	ELECTRIC GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS, (4)	15.21	NATURAL GAS	140	MW	2.5	PPM @ 15% O2	
FL-0244	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	EXISTING POWER PLANT	TURBINE, COMBINED CYLE, NATURAL GAS, (4)	15.21	NATURAL GAS	170	MW	2.5	PPM @ 15% O2	
FL-0244	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	EXISTING POWER PLANT	TURBINE, COMBINED CYCLE WITH DUCT BURNER, NAT GAS	15.21	NATURAL GAS	170	MW	2.5	PPM @ 15% O2	
FL-0245	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	FL	EXISTING POWER PLANT	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	15.21	NATURAL GAS	170	MW	2.5	PPM @ 15% O2	24 hr
WY-0061	BLACK HILLS CORP./NEIL SIMPSON TWO	BLACK HILLS CORP.	WY	STEAM ELECTRIC GENERATING PLANT	TURBINE, COMBINED CYCLE, & DUCT BURNER	15.21	NATURAL GAS	40	MW	2.5	PPM @ 15% O2	
OR-0040	KLAMATH GENERATION, LLC	KLAMATH GENERATION, LLC	OR	POWER GENERATION FACILITY	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS (2)	15.21	NATURAL GAS	480	MW	2.5	PPM @ 15% O2	
WA-0291	WALLULA POWER PLANT	WALLULA GENERATION, LLC	WA	WALLULA GENERATION, LLC, PROPOSES TO CONSTRUCT AND OPERATE A 1,300 MW COMBINED CYCLE ELECTRIC POWER PLANT. THE PROJECT WILL CONSIST OF TWO INDEPENDENT POWER BLOCKS WITH CRITICAL BACK-UP SYSTEMS TO MAINTAIN OVERALL PLANT RELIABILITY AND AVAILABILITY.	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	15.21	NATURAL GAS	1300	MW	2.5	PPM @ 15% O2	
MN-0053	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	MN	LARGE COMBUSTION TURBINE ELECTRIC POWER PLANT - INITIAL OPERATION IN SIMPLE CYCLE AND CONVERSION TO COMBINED CYCLE IN THE FUTURE.	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	15.21	NATURAL GAS	1876	MMBTU/H	3	PPMVD @ 15% 02	3 hr
MI-0357	KALKASKA GENERATING, INC	KALKASKA GENERATING LLC	MI	ELECTRICAL POWER PRODUCTION FACILITY.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	605	MW	3	PPM @ 15% O2	
MI-0361	SOUTH SHORE POWER LLC	SOUTH SHORE POWER LLC	MI	ELECTRIC POWER GENERATING FACILITY.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	172	MW	3	PPM @ 15% O2	
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CALPINE CORP.	CO	NATURAL GAS-FIRED, COMBINED-CYCLE COMBUSTION TURBINES.	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	15.21	NATURAL GAS	300	MW	3	PPM @ 15% O2	
NC-0101	FORSYTH ENERGY PLANT	FORSYTH ENERGY PROJECTS, LLC	NC	THREE COMBINED-CYCLE COMBUSTION TURBINE GENERATORS, EACH WITH A HEAT RECOVERY STEAM GENERATORS (HRSG) ALONG WITH NATURAL GAS-FIRED DUCT BURNERS TO MEET PEAK DEMAND. THE STEAM GENERATED THROUGH THE THREE HRSGS WILL DRIVE A STEAM TURBINE. THE ENTIRE PLANT WILL BE CAPABLE OF GENERATING A NOMINAL POWER OUTPUT OF 812 MEGAWATTS.	TURBINE, COMBINED CYCLE, NATURAL GAS, (3)	15.21	NATURAL GAS	1844	MMBTU/H	3	PPM @ 15% O2	
LA-0192	CRESCENT CITY POWER	CRESENT CITY POWER, LLC	LA	NEW 600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	GAS TURBINES - 187 MW (2)	15.21		2006	MMBTU/H	3	PPM	Annual

Table B-1
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for NO_x

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPU TUNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	DUKE ENERGY HANGING ROCK, LLC	OH	FOUR NATURAL GAS (NG) FIRED COMBUSTION TURBINES, WITH DUCT BURNERS; COMBINED CYCLE, EACH 172 MW	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON	15.21	NATURAL GAS	172	MW	3	PPM @ 15% O2	3 hr
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	DUKE ENERGY HANGING ROCK, LLC	OH	FOUR NATURAL GAS (NG) FIRED COMBUSTION TURBINES, WITH DUCT BURNERS; COMBINED CYCLE, EACH 172 MW	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF	15.21	NATURAL GAS	172	MW	3	PPM @ 15% O2	3 hr
MN-0054	MANKATO ENERGY CENTER		MN	COMBINED CYCLE GAS TURBINE ELECTRIC POWER PLANT. TWO IDENTICAL GE FRAME F7A GAS TURBINES EACH WITH HRSG W/DUCT BURNERS FEEDING STEAM TO COMMON STEAM TURBINES. PRIMARY FUEL IS NG, NO. 2 VERY LOW SULFUR DISTILLATE OIL FOR BACKUP. ALSO, AUX. BOILER, DIESEL EMERGENCY GNERATOR, DIESEL FIRE PUMP, AND 900,000 GAL ABOVE GROUN OIL STORAGE TANK.	COMBUSTION TURBINE, LARGE, 2 EACH	15.21	NATURAL GAS	1916	MMBTU/H	3	PPM @ 15% O2	
TX-0374	CHOCOLATE BAYOU PLANT	BP AMOCO CHEMICAL CO	TX	BP AMOCO PROPOSES TO CONSTRUCT A GAS- FIRED STEAM AND ELECTRIC GENERATING FACILITY. THE PROPOSED PROJECT WILL BE CALLED THE GREEN POWER UNIT ONE. THE PROJECT WILL CONSIST OF TWO DUAL SHAFT GAS-FIRED ELECTRIC GENERATING TURBINES EACH RATED AT APPROX. 35 MW (BASE LOAD), EACH TURBINE WILL HAVE A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH 312 MMBTU/H DUCT BURNERS. GREEN POWER UNIT ONE WILL BE CAPABLE OF PRODUCING AN ESTIMATED NOMINAL 70 MW OF ELECTRICITY. STEAM PRODUCED IN THE HRSGS WILL BE USED IN THE CHOCOLATE BAYOU WORKS CHEMICAL COMPLEX. THE CHEMICAL COMPLEX WILL CONSUME APPROX. HALF OF THE ELECTRICAL OUTPUT PRODUCED BY THE TWO NEW TURBINES. EXCESS POWER PRODUCED BY THE COMBUSTION TURBINES WILL BE SOLD TO THE GRID. THE COMBUSTION TURBINES WILL ONLY BURN PIPELINE QUALITY SWEET NAT GAS. THE DUCT BURNERS WILL BURN NAT GAS, COMPLEX GAS, OR MIXTURES OF NAT GAS AND COMPLEX GAS.	(2) COGENERATION TRAINS 2 & 3, GT-2 & 3	15.21	NAT GAS	70	MW, TOTAL	3.5	PPM @ 15% O2	
MI-0365	MIRANT WYANDOTTE LLC	MIRANT WYANDOTTE LLC	MI	COMBINED CYCLE POWER PLANT.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	2200	MMBTU/H	3.5	PPM @ 15% O2	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE	15.21	NATURAL GAS	230	MW	3.5	PPM @ 15% 02	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-002 GEN ELEC. COMB. TURBINE	15.21		230	MW	3.5	PPM @ 15% 02	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-003 GEN. ELEC COMB TURBINES	15.21		230	MW	3.5	PPM @ 15% 02	
*NE-0023	BEATRICE POWER STATION	NEBRASKA PUBLIC POWER DISTRICT	NE	PERMIT TO CONSTRUCT: 2-NG TURBINES, 250 MW TOTAL AND ONE AUX. BOILER, 73 MMBTU/HR, OIL FIRED	2-COMBUSTION TURBINES W/ DUCT BURNER	15.21	NATURAL GAS	250	MW	3.5	PPM @ 15% O2	
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	DUKE ENERGY NORTH AMERICA	OH	TWO 170 MW NATURAL GAS-FIRED COMBUSTION TURBINES, COMBINED CYCLE	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS ON	15.21	NATURAL GAS	170	MW	3.5	PPM @ 15% O2	
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	DUKE ENERGY NORTH AMERICA	OH	TWO 170 MW NATURAL GAS-FIRED COMBUSTION TURBINES, COMBINED CYCLE	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS OFF	15.21	NATURAL GAS	170	MW	3.5	PPM @ 15% O2	

Table B-1
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for NO_x

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPU TUNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
OK-0096	REDBUD POWER PLANT	REDBUD ENERGY LP	OK	ELECTRICITY GENERATION	COMBUSTION TURBINE AND DUCT BURNERS	15.21	NATURAL GAS	1832	MMBTU/H	3.5	PPM @ 15% O2	
NE-0017	BEATRICE POWER STATION	NEBRASKA PUBLIC POWER DISTRICT	NE	ELECTRIC GENERATING FACILITY	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	80	MW	3.5	PPM @ 15% O2	24 hr
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	DUKE ENERGY	OK	MERCHANT POWER PLANT - NOMINAL TOTAL OF 620 MW.	TURBINES, COMBINED CYCLE (2)	15.21	NATURAL GAS	1701	MMBTU/H	3.5	PPM @ 15% O2	
NV-0033	EL DORADO ENERGY, LLC	EL DORADO ENERGY, LLC	NV	THE FACILITY CONSIST OF TWO COMBUSTION TURBINE GENERATORS (CTGS) TWO HEAT RECOVERY STEAM GENERATORS (HRSGS) AND ONE STEAM TURBINE GENERATOR. THE FACILITY IS LOCATED IN AN ATTAINMENT AREA FOR ALL CRITERIA AIR POLLUTANTS. INSIGNIFICAN EMISSION UNITS INCLUDE A 140 HP EMERGENCY FIRE -WATER PUMP AND A WET SURFACE AIR COOLER.	COMBUSTION TURBINE, COMBINED CYCLE & COGEN(2)	15.21	NATURAL GAS	475	MW	3.7	PPM @ 15% O2	
MI-0363	BLUEWATER ENERGY CENTER LLC	BLUEWATER ENERGY CENTER LLC	MI	COMBINED CYCLE ELECTRIC GENERATING POWER PLANT.	TURBINE, COMBINED CYCLE, (3)	15.21	NATURAL GAS	180	MW	4.5	PPM @ 15% O2	
MN-0054	MANKATO ENERGY CENTER		MN	COMBINED CYCLE GAS TURBINE ELECTRIC POWER PLANT. TWO IDENTICAL GE FRAME F7A GAS TURBINES EACH WITH HRSG W/DUCT BURNERS FEEDING STEAM TO COMMON STEAM TURBINES. PRIMARY FUEL IS NG, NO. 2 VERY LOW SULFUR DISTILLATE OIL FOR BACKUP. ALSO, AUX. BOILER, DIESEL EMERGENCY GNERATOR, DIESEL FIRE PUMP, AND 900,000 GAL ABOVE GROUN OIL STORAGE TANK.	COMBUSTION TURBINE, LARGE 2 EACH	15.21	NATURAL GAS	1827	MMBTU/H	5.5	PPM @ 15% O2	
MI-0362	MIDLAND COGENERATION (MCV)	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	MI	COGENERATION FACILITY TO PRODUCE STEAM AND ELECTRICITY.	TURBINE, COMBINED CYCLE, (1)	15.21	NATURAL GAS	984	MMBTU/H	25	PPM @ 15% O2	
MI-0362	MIDLAND COGENERATION (MCV)	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	MI	COGENERATION FACILITY TO PRODUCE STEAM AND ELECTRICITY.	TURBINE, COMBINED CYCLE, (11)	15.21	NATURAL GAS	984	MMBTU/H	42	PPM @ 15% O2	

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
VA-0291	CPV WARREN LLC	CPV WARREN LLC	VA	COMBINED CYCLE POWER GENERATION	TURBINE, COMBINED CYCLE (2)	15.21	NATURAL GAS	1717	mmbtu/h	1.3	PPM @ 15% O2	
VA-0291	CPV WARREN LLC	CPV WARREN LLC	VA	COMBINED CYCLE POWER GENERATION	TURBINE, COMBINED CYCLE AND DUCT BURNER (2)	15.21	NATURAL GAS	1717	mmbtu/h	1.8	PPM @ 15% O2	
*OR-0041	WANAPA ENERGY CENTER	DIAMOND WANAPA I, L.P.	OR	A 1,200 MW NATURAL GAS-FIRED COMBINED CYCLE COMBUSTION TURBINE PROJECT EMPLOYING A WATER-COOLED STEAM CONDENSING SYSTEM. FOUR COMBUSTION TURBINES, FOUR HEAT RECOVERY STEAM GENERATORS, TWO STEAM TURBINES, AND TWO COOLING TOWERS EMPLOYED.	COMBUSTION TURBINE & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	2384	MMBTU/H	2	PPM @ 15% O2	
MI-0366	BERRIEN ENERGY, LLC	BERRIEN ENERGY, LLC	MI	ELECTRIC POWER GENERATING FACILITY.	3 COMBUSTION TURBINES AND DUCT BURNERS	15.21	NATURAL GAS	1584	MMBTU/H	2	PPM @ 15% O2	
OR-0039	COB ENERGY FACILITY, LLC	Peoples Energy Resources	OR	POWER GENERATION FACILITY	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	15.21	NATURAL GAS	1150	MW	2	PPM @ 15% O2	
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	AZ	POWER PLANT	TURBINE, COMBINED CYCLE	15.21	NATURAL GAS	325	MW	2	PPM @ 15% O2	
CA-1096	VERNON CITY LIGHT & POWER	VERNON CITY LIGHT & POWER	CA		GAS TURBINE: COMBINED CYCLE < 50 MW	15.21	NATURAL GAS	43	MW GAS TURBINE, 55 MW STEAM TURBINE	2	PPM @ 15% O2	
CA-1097	MAGNOLIA POWER PROJECT, SCPPA	MAGNOLIA POWER PROJECT, SCPPA	CA		GAS TURBINE: COMBINED CYCLE >= 50 MW	15.21	NATURAL GAS	181	NET MW (GAS TURBINE W/STEAM INJECTIO N)	2	PPM @ 15% O2	
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	SAVANNAH ELECTRIC AND POWER CO	GA	ELECTRIC GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS, (4)	15.21	NATURAL GAS	140	MW	2	PPM @ 15% O2	
WA-0315	SUMAS ENERGY 2 GENERATION FACILITY	SUMAS ENERGY 2 GENERATION FACILITY	WA		TURBINES, COMBINED CYCLE, (2)	15.21	NATURAL GAS	660	MW	2	PPM @ 15% O2	
WA-0291	WALLULA POWER PLANT	WALLULA GENERATION, LLC	WA	WALLULA GENERATION, LLC, PROPOSES TO CONSTRUCT AND OPERATE A 1,300 MW COMBINED CYCLE ELECTRIC POWER PLANT. THE PROJECT WILL CONSIST OF TWO INDEPENDENT POWER BLOCKS WITH CRITICAL BACK-UP SYSTEMS TO MAINTAIN OVERALL PLANT RELIABILITY AND AVAILABILITY.	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	15.21	NATURAL GAS	1300	MW	2	PPM @ 15% O2	
CEC DECISION PENDING	SOUTH BAY REPLACEMENT PROJECT	LSP SOUTH BAY, LLC	CA	REPLACEMENT OF EXISTING FACILITY IN CHULA VISTA IN SAN DIEGO COUNTY WITH A 620 MW NATURAL GAS-FIRED COMBINED-CYCLE PLANT WITH TWO CTGs, TWO HRSGs AND DUCT BURNERS AND STEAM TURBINE	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	620	MW	2	PPMVD	1 hr

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
CO-0056	ROCKY MOUNTAIN ENERGY CENTER, LLC	CALPINE CORP.	CO	NATURAL GAS-FIRED, COMBINED-CYCLE COMBUSTION TURBINES.	NATURAL-GAS FIRED, COMBINED-CYCLE TURBINE	15.21	NATURAL GAS	300	MW	3	PPM @ 15 O2	
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	AZ	COMBINED CYCLE GAS-FIRED ELECTRICITY GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	15.21	NATURAL GAS	170	MW	3	PPM @ 15% O2	
AZ-0047	WELLTON MOHAWK GENERATING STATION	DOME VALLEY ENERGY PARTNERS	AZ	COMBINED CYCLE GAS-FIRED ELECTRICITY GENERATING STATION	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	15.21	NATURAL GAS	180	MW	3	PPM @ 15% O2	
UT-0066	CURRANT CREEK	PACIFICORP	UT	POWER GENERATION PLANT WITH TWO NATURAL GAS COMBINED CYCLE TURBINES	NATURAL GAS FIRED TURBINES AND HEAT RECOVERY STEAM GENERATORS	15.21	NATURAL GAS			3	PPM @ 15% O2	3 hr
NV-0037	COPPER MOUNTAIN POWER	SEMPRA ENERGY RESOURCES	NV	A 600 MW COMBINED CYCLE ELECTRICAL GENERATION FACILITY CONSISTING OF TWO COMBUSTION TURBINE GENERATORS WITH HEAT RECOVERY STEAM GENERATORS, ONE STEAM TURBINE GENERATOR, AND ONE AUXILIARY BOILER.	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	15.21	NATURAL GAS	600	MW	3	PPM @ 15% O2	
AZ-0043	DUKE ENERGY ARLINGTON VALLEY (AVEFII)	DUKE ENERGY ARLINGTON VALLEY	AZ	POWER PLANT	TURBINE, COMBINED CYCLE & DUCT BURNER	15.21	NATURAL GAS	325	MW	3	PPM @ 15% O2	
*AZ-0049	LA PAZ GENERATING FACILITY	ALLEGHENY ENERGY SUPPLY LLC	AZ	NATURAL GAS FIRED, COMBINED CYCLE GENERATING STATION	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	15.21	NATURAL GAS	1040	MW	3	PPM @ 15% O2	3 hr
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	NV	2 - NATURAL GAS FIRED COMBINED CYCLE COMBUSTION TURBINE GENERATORS WITH HRSG"S AND DUCT BURNERS. 2 - NATURAL GAS FIRED FUEL PREHEATERS. 1 - NATURAL GAS FIRED AUXILIARY BOILER	TURBINE, COMBINED CYCLE COMBUSTION #1 WITH HRSG AND DUCT BURNER.	15.21	NATURAL GAS	306	MW	3.5	PPM @ 15% O2	
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	NV	2 - NATURAL GAS FIRED COMBINED CYCLE COMBUSTION TURBINE GENERATORS WITH HRSG"S AND DUCT BURNERS. 2 - NATURAL GAS FIRED FUEL PREHEATERS. 1 - NATURAL GAS FIRED AUXILIARY BOILER	TURBINE, COMBINED CYCLE COMBUSTION #2 WITH HRSG AND DUCT BURNER.	15.21	NATURAL GAS	306	MW	3.5	PPM @ 15% O2	
NV-0033	EL DORADO ENERGY, LLC	EL DORADO ENERGY, LLC	NV	THE FACILITY CONSIST OF TWO COMBUSTION TURBINE GENERATORS (CTGS) TWO HEAT RECOVERY STEAM GENERATORS (HRSGS) AND ONE STEAM TURBINE GENERATOR. THE FACILITY IS LOCATED IN AN ATTAINMENT AREA FOR ALL CRITERIA AIR POLLUTANTS. INSIGNIFICAN EMISSION UNITS INCLUDE A 140 HP EMERGENCY FIRE -WATER PUMP AND A WET SURFACE AIR COOLER.	COMBUSTION TURBINE, COMBINED CYCLE & COGEN(2)	15.21	NATURAL GAS	475	MW	3.5	PPM @ 15% O2	

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
MI-0365	MIRANT WYANDOTTE LLC	MIRANT WYANDOTTE LLC	MI	COMBINED CYCLE POWER PLANT.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	2200	MMBTU/H	3.8	PPM @ 15% O2	
LA-0192	CRESCENT CITY POWER	CRESENT CITY POWER, LLC	LA	NEW 600 MW NATURAL GAS-FIRED COMBINED CYCLE POWER PLANT	GAS TURBINES - 187 MW (2)	15.21		2006	MMBTU/H	4	PPM @ 15%O2	Annual
NV-0038	IVANPAH ENERGY CENTER, L.P.	IVANPAH ENERGY CENTER, L.P.	NV	A 500 MW ELECTRICAL GENERATING PLANT CONSISTING OF TWO COMBUSTION TURBINE GENERATORS, TWO HEAT RECOVERY STEAM GENERATORS, ONE STEAM TURBINE GENERATOR. THE PROPOSED PLANT IS SURROUNDED BY UNOCCUPIED LAND FOR A DISTANCE OF AT LEAST TWO MILES IN ALL DIRECTIONS. THE UN-IMPROVED ACCESS ROAD TO THE PROPOSED PLANT SITE IS ABOUT 1.6 MILES IN LENGTH.	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	15.21	NATURAL GAS	500	MW	4	PPM @ 15% O2	1 hr
MN-0054	MANKATO ENERGY CENTER		MN	COMBINED CYCLE GAS TURBINE ELECTRIC POWER PLANT. TWO IDENTICAL GE FRAME F7A GAS TURBINES EACH WITH HRSG W/DUCT BURNERS FEEDING STEAM TO COMMON STEAM TURBINES. PRIMARY FUEL IS NG, NO. 2 VERY LOW SULFUR DISTILLATE OIL FOR BACKUP. ALSO, AUX. BOILER, DIESEL EMERGENCY GNERATOR, DIESEL FIRE PUMP, AND 900,000 GAL ABOVE GROUN OIL STORAGE TANK.	COMBUSTION TURBINE, LARGE, 2 EACH	15.21	NATURAL GAS	1916	MMBTU/H	4	PPM @ 15% O2	
CA-0997	SACRAMENTO MUNICIPAL UTILITY DISTRICT	SACRAMENTO MUNICIPAL UTILITY DISTRICT	CA	COMBUSTION GAS TURBINE GE 7FA	GAS TURBINES, (2)	15.21	NATURAL GAS	1611	MMBTU/H	4	PPM @ 15% O2	
MI-0361	SOUTH SHORE POWER LLC	SOUTH SHORE POWER LLC	MI	ELECTRIC POWER GENERATING FACILITY.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	172	MW	4	PPM @ 15% O2	
not listed	ROSEVILLE ENERGY PARK	ROSEVILLE ELECTRIC	CA	160 MW, NATURAL GAS-FIRED, COMBINED-CYCLE GENERATING FACILITY LOCATED WEST OF DOWNTOWN ROSEVILLE, IN PLACER COUNTY. IT WILL HAVE TWO GE LM6000 PC SPRINT OR ALSTOM GTX100 CTGs, EQUIPPED WITH WATER INJECTION (LM6000) OR DRY LOW-NOx COMBUSTERS (GTX100), TWO HRSGs WITH DUCT BURNERS, ONE STEAM TURBINE, CONDENSERS AND A MECHANICAL DRAFT COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	160	MW	4	PPMVD	1 hr
not listed	EL CENTRO UNIT 3 REPOWER PROJECT	IMPERIAL IRRIGATION DISTRICT	CA	128 MW, NATURAL GAS-FIRED COMBINED-CYCLE GENERATING FACILITY WITHIN CURRENT EL CENTRO GENERATING STATION, IN IMPERIAL COUNTY. IT WILL ADD A GE 7EA CTG WITH DRY LOW NOX COMBUSTERS AND ONE HRSG WITH DUCT BURNER TO EXISTING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	128	MW	4	PPMVD	1 hr
not listed	BLYTHE ENERGY PROJECT, PHASE II	CAITHNESS BLYTHE II, LLC	CA	520 MW NATURAL GAS-FIRED COMBINED-CYCLE GENERATING FACILITY ADJACENT TO BLYTHE ENERGY PROJECT PHASE I. IT WILL HAVE TWO SEIMENS WESTINGHOUSE CGTS WITH DRY LOW-NOX COMBUSTERS, TWO HRSGs WITH DUCT BURNERS, ONE STEAM TURBINE, CONDENERS AND A COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	520	MW	4	PPMVD	1 hr

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
MN-0054	MANKATO ENERGY CENTER		MN	COMBINED CYCLE GAS TURBINE ELECTRIC POWER PLANT. TWO IDENTICAL GE FRAME F7A GAS TURBINES EACH WITH HRSG W/DUCT BURNERS FEEDING STEAM TO COMMON STEAM TURBINES. PRIMARY FUEL IS NG, NO. 2 VERY LOW SULFUR DISTILLATE OIL FOR BACKUP. ALSO, AUX. BOILER, DIESEL EMERGENCY GNERATOR, DIESEL FIRE PUMP, AND 900,000 GAL ABOVE GROUN OIL STORAGE TANK.	COMBUSTION TURBINE, LARGE 2 EACH	15.21	NATURAL GAS	1827	MMBTU/H	4.8	PPM @ 15% O2	
OR-0040	KLAMATH GENERATION, LLC	KLAMATH GENERATION, LLC	OR	POWER GENERATION FACILITY	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS (2)	15.21	NATURAL GAS	480	MW	5	PPM @ 15% O2	
MI-0357	KALKASKA GENERATING, INC	KALKASKA GENERATING LLC	MI	ELECTRICAL POWER PRODUCTION FACILITY.	TURBINE, COMBINED CYCLE, (2)	15.21	NATURAL GAS	605	MW	5	PPM @ 15% O2	
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	DUKE ENERGY HANGING ROCK, LLC	OH	FOUR NATURAL GAS (NG) FIRED COMBUSTION TURBINES, WITH DUCT BURNERS; COMBINED CYCLE, EACH 172 MW	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF	15.21	NATURAL GAS	172	MW	6	PPM @ 15% O2	24 hr
FL-0245	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	FL	EXISTING POWER PLANT	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	15.21	NATURAL GAS	170	MW	7.4	PPM @ 15% O2	
FL-0263	FPL TURKEY POINT POWER PLANT	FLORIDA POWER AND LIGHT	FL	RESPECTIVELY."	170 MW COMBUSTION TURBINE, 4 UNITS	15.21	NATURAL GAS	170	MW	7.6	PPM @ 15 % O2	
FL-0265	HINES POWER BLOCK 4	PROGRESS ENERGY	FL	COMBINED CYCLE POWER PLANT. THIS IS THE 4TH BLOCK OF POWER ADDED, MAKING THE TOTAL GENERATING CAPACITY OF THE FACILITY APPROXIMATELY 2090 MW.	COMBINED CYCLE TURBINE	15.21	NATURAL GAS	530	MW	8	PPM @ 15% O2	
MI-0363	BLUEWATER ENERGY CENTER LLC	BLUEWATER ENERGY CENTER LLC	MI	COMBINED CYCLE ELECTRIC GENERATING POWER PLANT.	TURBINE, COMBINED CYCLE, (3)	15.21	NATURAL GAS	180	MW	8	PPM @ 15% O2	
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	DUKE ENERGY HANGING ROCK, LLC	OH	FOUR NATURAL GAS (NG) FIRED COMBUSTION TURBINES, WITH DUCT BURNERS; COMBINED CYCLE, EACH 172 MW	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON	15.21	NATURAL GAS	172	MW	9	PPM @ 15% O2	24 hr
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	VA	POWER PLANT	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	NATURAL GAS	170	MW	9	PPM @ 15% O2	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	VA	POWER GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS	15.21	NATURAL GAS	1973	MMBTU/H	9	PPM @ 15% O2	
CEC DECISION PENDING	LOS ESTEROS CRITICAL ENERGY FACILITY, PHASE II	LOS ESTEROS CRITICAL ENERGY FACILITY, LLC	CA	CONVERSION OF EXISTING 180 MW SIMPLE-CYCLE POWER PLANT TO A 320 MW COMBINED-CYCLE PLANT IN SANTA CLARA COUNTY WITH ADDITION OF FOUR HRSGs WITH DUCT BURNERS, STEAM TURBINE, CONDENSERS AND A COOLING TOWER	TURBINE, COMBINED CYCLE, NATURAL GAS & HEAT RECOVERY STEAM GENERATOR	15.21	NATURAL GAS	320	MW	9	PPMVD	1 hr
MN-0053	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	MN	LARGE COMBUSTION TURBINE ELECTRIC POWER PLANT - INITIAL OPERATION IN SIMPLE CYCLE AND CONVERSION TO COMBINED CYCLE IN THE FUTURE.	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	15.21	NATURAL GAS	1876	MMBTU/H	10	PPMVD @ 15% O2	3 hr

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
FL-0256	HINES ENERGY COMPLEX, POWER BLOCK 3	PROGRESS ENERGY FLORIDA	FL	POWER PLANT	COMBUSTION TURBINES, COMBINED CYCLE, NATURAL GAS,2	15.21	NATURAL GAS	1830	MMBTU/H	10	PPMVD @15% O2	
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	DUKE ENERGY NORTH AMERICA	OH	TWO 170 MW NATURAL GAS-FIRED COMBUSTION TURBINES, COMBINED CYCLE	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS OFF	15.21	NATURAL GAS	170	MW	10	PPM @ 15% O2	
FL-0244	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	EXISTING POWER PLANT	TURBINE, COMBINED CYLE, NATURAL GAS, (4)	15.21	NATURAL GAS	170	MW	10	PPM @ 15% O2	
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	DUKE ENERGY	OK	MERCHANT POWER PLANT - NOMINAL TOTAL OF 620 MW.	TURBINES, COMBINED CYCLE (2)	15.21	NATURAL GAS	1701	MMBTU/H	10	PPM @ 15% O2	
NC-0101	FORSYTH ENERGY PLANT	FORSYTH ENERGY PROJECTS, LLC	NC	THREE COMBINED-CYCLE COMBUSTION TURBINE GENERATORS, EACH WITH A HEAT RECOVERY STEAM GENERATORS (HRSG) ALONG WITH NATURAL GAS-FIRED DUCT BURNERS TO MEET PEAK DEMAND. THE STEAM GENERATED THROUGH THE THREE HRSGS WILL DRIVE A STEAM TURBINE. THE ENTIRE PLANT WILL BE CAPABLE OF GENERATING A NOMINAL POWER OUTPUT OF 812 MEGAWATTS.	TURBINE, COMBINED CYCLE, NATURAL GAS, (3)	15.21	NATURAL GAS	1844	MMBTU/H	11.6	PPM @ 15% O2	
VA-0287	JAMES CITY ENERGY PARK	JAMES CITY ENERGY PARK LLC	VA	POWER GENERATING FACILITY	TURBINE, COMBINED CYCLE, NATURAL GAS,DUCT BURNER	15.21	NATURAL GAS	1973	MMBTU/H	12	PPM @ 15% O2	
MI-0362	MIDLAND COGENERATIO N (MCV)	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	MI	COGENERATION FACILITY TO PRODUCE STEAM AND ELECTRICITY.	TURBINE, COMBINED CYCLE, (11)	15.21	NATURAL GAS	984	MMBTU/H	12	PPM @ 15% O2	
MI-0362	MIDLAND COGENERATIO N (MCV)	MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP	MI	COGENERATION FACILITY TO PRODUCE STEAM AND ELECTRICITY.	TURBINE, COMBINED CYCLE, (1)	15.21	NATURAL GAS	984	MMBTU/H	12	PPM @ 15% O2	
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	DUKE ENERGY NORTH AMERICA	OH	TWO 170 MW NATURAL GAS-FIRED COMBUSTION TURBINES, COMBINED CYCLE	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS ON	15.21	NATURAL GAS	170	MW	14	PPM @ 15% O2	
VA-0289	DUKE ENERGY WYTHE, LLC	DUKE ENERGY WYTHE, LLC	VA	POWER PLANT	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	15.21	NATURAL GAS	170	MW	14.6	PPM @ 15% O2	
OK-0096	REDBUD POWER PLANT	REDBUD ENERGY LP	OK	ELECTRICITY GENERATION	COMBUSTION TURBINE AND DUCT BURNERS	15.21	NATURAL GAS	1832	MMBTU/H	17.2	PPM @ 15% O2	
MN-0060	HIGH BRIDGE GENERATING PLANT	NORTHERN STATES POWER CO. DBA XCEL ENERGY	MN	EXISTING COAL-FIRED ELECTRIC UTILITY THAT WILL BE REPLACED BY NEW TWIN NATURAL GAS-FIRED COMBINED CYCLE COMBUSTION TURBINE.	2 COMBINED-CYCLE COMBUSTION TURBINES	15.21	NATURAL GAS ONLY	330	MEGAWA TTS	18	PPM @ 15% O2	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-001 GEN. ELEC. COMBUST. TURBINE	15.21	NATURAL GAS	230	MW	18	PPM @ 15% 02	
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-002 GEN ELEC. COMB. TURBINE	15.21		230	MW	18.36	PPM @ 15% 02	

Table B-2
Natural Gas Fired, Combined-Cycle Combustion Turbines > 25 MW 1/1/2003 - 12/30/2006,
Emission Limits for CO

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	FACILITY DESCRIPTION	PROCESS NAME	PROC TYPE	FUEL	THRU PUT	THRUPUT UNIT	STD EMISS LIMIT	STD UNIT LIMIT	STD LIMIT AVG TIME CONDITION
MS-0073	RELIANT ENERGY CHOCTAW COUNTY, LLC		MS	THREE GE COMBINE CYCLE TURBINED RATED @ 230 MEGAWATTS EACH WITH SCR FOR POLLUTION CONTROL	EMISSION POINT AA-003 GEN. ELEC COMB TURBINES	15.21		230	MW	18.36	PPM @ 15% 02	
TX-0374	CHOCOLATE BAYOU PLANT	BP AMOCO CHEMICAL CO	TX	BP AMOCO PROPOSES TO CONSTRUCT A GAS- FIRED STEAM AND ELECTRIC GENERATING FACILITY. THE PROPOSED PROJECT WILL BE CALLED THE GREEN POWER UNIT ONE. THE PROJECT WILL CONSIST OF TWO DUAL SHAFT GAS-FIRED ELECTRIC GENERATING TURBINES EACH RATED AT APPROX. 35 MW (BASE LOAD), EACH TURBINE WILL HAVE A HEAT RECOVERY STEAM GENERATOR (HRSG) EQUIPPED WITH 312 MMBTU/H DUCT BURNERS. GREEN POWER UNIT ONE WILL BE CAPABLE OF PRODUCING AN ESTIMATED NOMINAL 70 MW OF ELECTRICITY. STEAM PRODUCED IN THE HRSGS WILL BE USED IN THE CHOCOLATE BAYOU WORKS CHEMICAL COMPLEX. THE CHEMICAL COMPLEX WILL CONSUME APPROX. HALF OF THE ELECTRICAL OUTPUT PRODUCED BY THE TWO NEW TURBINES. EXCESS POWER PRODUCED BY THE COMBUSTION TURBINES WILL BE SOLD TO THE GRID. THE COMBUSTION TURBINES WILL ONLY BURN PIPELINE QUALITY SWEET NAT GAS. THE DUCT BURNERS WILL BURN NAT GAS, COMPLEX GAS, OR MIXTURES OF NAT GAS AND COMPLEX GAS.	(2) COGENERATION TRAINS 2 & 3, GT-2 & 3	15.21	NAT GAS	70	MW, TOTAL	24.4	PPM @ 15% O2S	Annual
NC-0101	FORSYTH ENERGY PLANT	FORSYTH ENERGY PROJECTS, LLC	NC	THREE COMBINED-CYCLE COMBUSTION TURBINE GENERATORS, EACH WITH A HEAT RECOVERY STEAM GENERATORS (HRSG) ALONG WITH NATURAL GAS-FIRED DUCT BURNERS TO MEET PEAK DEMAND. THE STEAM GENERATED THROUGH THE THREE HRSGS WILL DRIVE A STEAM TURBINE. THE ENTIRE PLANT WILL BE CAPABLE OF GENERATING A NOMINAL POWER OUTPUT OF 812 MEGAWATTS.	TURBINE & DUCT BURNER, COMBINED CYCLE, NAT GAS, 3	15.21	NATURAL GAS	1844	MMBTU/H	25.9	PPM @ 15% O2	
WY-0061	BLACK HILLS CORP./NEIL SIMPSON TWO	BLACK HILLS CORP.	WY	STEAM ELECTRIC GENERATING PLANT	TURBINE, COMBINED CYCLE, & DUCT BURNER	15.21	NATURAL GAS	40	MW	37.2	PPM @ 15% O2	

Appendix C

Emissions Data

Table C-1 Maximum Annual Emission Summary - All Sources

Source	NO_x	CO	VOC	PM_{10}	SO_2
	tpy	tpy	tpy	tpy	tpy
Gas Turbines	107.4	252.7	34.24	117.1	8.28
Auxiliary Boiler	0.10	0.65	0.05	0.065	0.005
HTF Heater	0.22	1.48	0.11	0.15	0.012
Emergency Generator	0.67	0.39	0.04	0.0222	0.0007
Fire Water Pump	0.03	0.026	0.001	0.0015	0.00005
Cooling Tower	n/a	n/a	n/a	3.6	n/a
Totals	108.4	255.3	34.4	120.9	8.30

Table C-2 Combustion Turbine Emissions

ENSR Case Number	Ambient temp., F	Relative humidity	Evaporative Cooling	Combustion Turbines Operating	Combustion Turbine Load	Combustion Turbine Heat Input, MMBtu/hr HHV each	Duct Burner Heat Input, MMBtu/hr HHV each	Solar	NOx Permit Limit, ppmvd at 15% O2	NOx, lb/hr
Case 1	18	60%	Evap Off	2	100%	1,736.4	-	No Solar	2.0	12.55
Case 2	59	60%	Evap On	2	100%	1,636.2	-	No Solar	2.0	11.83
Case 3	77	40%	Evap On	2	100%	1,599.6	-	No Solar	2.0	11.56
Case 4	98	28%	Evap On	2	100%	1,555.7	-	No Solar	2.0	11.25
Case 5	105	28%	Evap On	2	100%	1,535.3	-	No Solar	2.0	11.10
Case 6	18	60%	Evap Off	2	100%	1,736.4	424.3	No Solar	2.0	15.60
Case 7	59	60%	Evap On	2	100%	1,636.2	424.3	No Solar	2.0	14.88
Case 8	77	40%	Evap On	2	100%	1,599.6	424.3	No Solar	2.0	14.61
Case 9	98	28%	Evap On	2	100%	1,555.7	424.3	No Solar	2.0	14.30
Case 10	105	28%	Evap On	2	100%	1,535.3	424.3	No Solar	2.0	14.15
Case 11	18	60%	Evap Off	2	100%	1,736.4	212.1	w/ Solar	2.0	14.08
Case 12	59	60%	Evap On	2	100%	1,636.2	212.1	w/ Solar	2.0	13.35
Case 13	77	40%	Evap On	2	100%	1,599.6	212.1	w/ Solar	2.0	13.09
Case 14	98	28%	Evap On	2	100%	1,555.7	212.1	w/ Solar	2.0	12.77
Case 15	105	28%	Evap On	2	100%	1,535.3	212.1	w/ Solar	2.0	12.62
Case 16	18	60%	Evap Off	1	100%	1,736.4	-	No Solar	2.0	12.55
Case 17	59	60%	Evap On	1	100%	1,636.2	-	No Solar	2.0	11.83
Case 18	77	40%	Evap On	1	100%	1,599.6	-	No Solar	2.0	11.56
Case 19	98	28%	Evap On	1	100%	1,555.7	-	No Solar	2.0	11.25
Case 20	105	28%	Evap On	1	100%	1,535.3	-	No Solar	2.0	11.10
Case 21	18	60%	Evap Off	1	100%	1,736.4	212.1	No Solar	2.0	14.08
Case 22	59	60%	Evap On	1	100%	1,636.2	212.1	No Solar	2.0	13.35
Case 23	77	40%	Evap On	1	100%	1,599.6	212.1	No Solar	2.0	13.09
Case 24	98	28%	Evap On	1	100%	1,555.7	212.1	No Solar	2.0	12.77
Case 25	105	28%	Evap On	1	100%	1,535.3	212.1	No Solar	2.0	12.62
Case 26	18	60%	Evap Off	1	100%	1,736.4	106.1	w/ Solar	2.0	13.32
Case 27	59	60%	Evap On	1	100%	1,636.2	106.1	w/ Solar	2.0	12.59
Case 28	77	40%	Evap On	1	100%	1,599.6	106.1	w/ Solar	2.0	12.33
Case 29	98	28%	Evap On	1	100%	1,555.7	106.1	w/ Solar	2.0	12.01
Case 30	105	28%	Evap On	1	100%	1,535.3	106.1	w/ Solar	2.0	11.86
Case 31	18	60%	Evap Off	2	75%	1,413.4	-	No Solar	2.0	10.22
Case 32	59	60%	Evap Off	2	75%	1,317.7	-	No Solar	2.0	9.53
Case 33	77	40%	Evap Off	2	75%	1,272.6	-	No Solar	2.0	9.20
Case 34	98	28%	Evap Off	2	75%	1,205.1	-	No Solar	2.0	8.71
Case 35	105	28%	Evap Off	2	75%	1,178.7	-	No Solar	2.0	8.52
Case 36	18	60%	Evap Off	2	50%	1,123.9	-	No Solar	2.0	8.12
Case 37	59	60%	Evap Off	2	50%	1,052.6	-	No Solar	2.0	7.61
Case 38	77	40%	Evap Off	2	50%	1,014.0	-	No Solar	2.0	7.33
Case 39	98	28%	Evap Off	2	50%	959.6	-	No Solar	2.0	6.94
Case 40	105	28%	Evap Off	2	50%	939.2	-	No Solar	2.0	6.79
Case 41	18	60%	Evap Off	1	75%	1,413.4	-	No Solar	2.0	10.22
Case 42	59	60%	Evap Off	1	75%	1,317.7	-	No Solar	2.0	9.53
Case 43	77	40%	Evap Off	1	75%	1,272.6	-	No Solar	2.0	9.20
Case 44	98	28%	Evap Off	1	75%	1,205.1	-	No Solar	2.0	8.71
Case 45	105	28%	Evap Off	1	75%	1,178.7	-	No Solar	2.0	8.52
Case 46	18	60%	Evap Off	1	50%	1,123.9	-	No Solar	2.0	8.12
Case 47	59	60%	Evap Off	1	50%	1,052.6	-	No Solar	2.0	7.61
Case 48	77	40%	Evap Off	1	50%	1,014.0	-	No Solar	2.0	7.33
Case 49	98	28%	Evap Off	1	50%	959.6	-	No Solar	2.0	6.94
Case 50	105	28%	Evap Off	1	50%	939.2	-	No Solar	2.0	6.79

Table C-2 Combustion Turbine Emissions

ENSR Case Number	CO Permit Limit, ppmvd at 15% O2	CO Emissions at Permit Limit, lb/hr	VOC Permit Limit, ppmvd at 15% O2	VOC Emissions at Permit Limit, lb/hr	PM10 front and backhalf, lb/hr	SO2, lb/hr	NH3 Slip, ppmvd at 15% O2	NH3 Slip, lb/hr	Stack Gas Flow, acfm	Stack gas temp., F	Stack Diameter	Stack Gas Exit Velocity, ft/min
Case 1	2.00	7.64	1.40	3.06	12.0	0.968	5.0	11.6	1,090,481	197.3	18.5	4,057
Case 2	2.00	7.20	1.40	2.89	12.0	0.912	5.0	10.9	1,023,125	194.8	18.5	3,806
Case 3	2.00	7.04	1.40	2.82	12.0	0.891	5.0	10.7	1,001,784	195.3	18.5	3,727
Case 4	2.00	6.85	1.40	2.74	12.0	0.867	5.0	10.4	976,540	196.1	18.5	3,633
Case 5	2.00	6.76	1.40	2.71	12.0	0.856	5.0	10.3	964,649	196.4	18.5	3,589
Case 6	3.00	14.25	2.00	5.44	18.0	1.204	5.0	14.4	1,069,878	179.4	18.5	3,980
Case 7	3.00	13.59	2.00	5.19	18.0	1.148	5.0	13.8	1,007,442	178.6	18.5	3,748
Case 8	3.00	13.34	2.00	5.10	18.0	1.128	5.0	13.5	986,079	178.8	18.5	3,668
Case 9	3.00	13.05	2.00	4.98	18.0	1.103	5.0	13.2	960,965	179.0	18.5	3,575
Case 10	3.00	12.92	2.00	4.93	18.0	1.092	5.0	13.1	948,891	179.2	18.5	3,530
Case 11	3.00	12.86	2.00	4.91	18.0	1.086	5.0	13.0	1,060,638	176.7	18.5	3,946
Case 12	3.00	12.19	2.00	4.66	18.0	1.030	5.0	12.4	996,395	174.5	18.5	3,707
Case 13	3.00	11.95	2.00	4.56	18.0	1.010	5.0	12.1	975,219	174.6	18.5	3,628
Case 14	3.00	11.66	2.00	4.45	18.0	0.985	5.0	11.8	949,809	174.9	18.5	3,533
Case 15	3.00	11.53	2.00	4.40	18.0	0.974	5.0	11.7	937,851	175.1	18.5	3,489
Case 16	2.00	7.64	1.40	3.06	12.0	0.968	5.0	11.6	1,070,665	185.7	18.5	3,983
Case 17	2.00	7.20	1.40	2.89	12.0	0.912	5.0	10.9	1,000,705	180.3	18.5	3,723
Case 18	2.00	7.04	1.40	2.82	12.0	0.891	5.0	10.7	978,288	179.9	18.5	3,639
Case 19	2.00	6.85	1.40	2.74	12.0	0.867	5.0	10.4	953,733	180.7	18.5	3,548
Case 20	2.00	6.76	1.40	2.71	12.0	0.856	5.0	10.3	942,180	181.3	18.5	3,505
Case 21	3.00	12.86	2.00	4.91	18.0	1.086	5.0	13.0	1,054,210	172.7	18.5	3,922
Case 22	3.00	12.19	2.00	4.66	18.0	1.030	5.0	12.4	987,072	168.7	18.5	3,672
Case 23	3.00	11.95	2.00	4.56	18.0	1.010	5.0	12.1	967,185	169.3	18.5	3,598
Case 24	3.00	11.66	2.00	4.45	18.0	0.985	5.0	11.8	942,531	170.1	18.5	3,506
Case 25	3.00	11.53	2.00	4.40	18.0	0.974	5.0	11.7	931,192	170.5	18.5	3,464
Case 26	3.00	12.16	2.00	4.64	18.0	1.027	5.0	12.3	1,040,565	165.8	18.5	3,871
Case 27	3.00	11.50	2.00	4.39	18.0	0.971	5.0	11.7	976,377	163.4	18.5	3,632
Case 28	3.00	11.26	2.00	4.30	18.0	0.951	5.0	11.4	956,169	163.9	18.5	3,557
Case 29	3.00	10.97	2.00	4.19	18.0	0.926	5.0	11.1	932,310	164.6	18.5	3,468
Case 30	3.00	10.83	2.00	4.14	18.0	0.915	5.0	11.0	920,586	165.0	18.5	3,425
Case 31	2.00	6.22	1.40	2.49	12.0	0.788	5.0	9.5	840,560	180.6	18.5	3,127
Case 32	2.00	5.80	1.40	2.32	12.0	0.734	5.0	8.8	796,399	180.2	18.5	2,963
Case 33	2.00	5.60	1.40	2.25	12.0	0.709	5.0	8.5	778,360	180.4	18.5	2,896
Case 34	2.00	5.30	1.40	2.13	12.0	0.672	5.0	8.1	746,948	180.1	18.5	2,779
Case 35	2.00	5.19	1.40	2.08	12.0	0.657	5.0	7.9	737,862	180.7	18.5	2,745
Case 36	2.00	4.95	1.40	1.98	12.0	0.626	5.0	7.5	673,426	172.0	18.5	2,505
Case 37	2.00	4.63	1.40	1.86	12.0	0.587	5.0	7.0	650,883	171.8	18.5	2,421
Case 38	2.00	4.46	1.40	1.79	12.0	0.565	5.0	6.8	640,474	172.0	18.5	2,383
Case 39	2.00	4.22	1.40	1.69	12.0	0.535	5.0	6.4	628,590	177.2	18.5	2,338
Case 40	2.00	4.14	1.40	1.66	12.0	0.523	5.0	6.3	623,348	178.3	18.5	2,319
Case 41	2.00	6.22	1.40	2.49	12.0	0.788	5.0	9.5	835,491	176.8	18.5	3,108
Case 42	2.00	5.80	1.40	2.32	12.0	0.734	5.0	8.8	784,636	170.8	18.5	2,919
Case 43	2.00	5.60	1.40	2.25	12.0	0.709	5.0	8.5	765,600	169.7	18.5	2,848
Case 44	2.00	5.30	1.40	2.13	12.0	0.672	5.0	8.1	735,538	170.6	18.5	2,736
Case 45	2.00	5.19	1.40	2.08	12.0	0.657	5.0	7.9	727,418	171.6	18.5	2,706
Case 46	2.00	4.95	1.40	1.98	12.0	0.626	5.0	7.5	667,811	166.8	18.5	2,484
Case 47	2.00	4.63	1.40	1.86	12.0	0.587	5.0	7.0	643,302	164.5	18.5	2,393
Case 48	2.00	4.46	1.40	1.79	12.0	0.565	5.0	6.8	633,378	164.9	18.5	2,356
Case 49	2.00	4.22	1.40	1.69	12.0	0.535	5.0	6.4	617,895	166.3	18.5	2,299
Case 50	2.00	4.14	1.40	1.66	12.0	0.523	5.0	6.3	613,118	167.6	18.5	2,281

Sulfur content of natural gas is assumed to be 0.2 gr/100 scf.

Natural Gas higher heating value is 1,024 Btu/scf.

As a worst case, it is assumed that up 100% of S may be emitted as SO2.

Stack height is 164 ft and diameter is 18.5 ft per GE proposal

PM10 emissions are based on review of stack test data.

Emissions of NOx, VOC, and CO are based on GE guarantees.

Table C-3 Comparison of Emissions for Continuous Operation to Emissions with Startups and Shutdowns

Continuous Operation Emissions (100% load, 77 F, 8,760 total hr/yr)	**Operating**	**NO_x**	**NO_x**	**CO**	**CO**	**VOC**	**VOC**	**PM_{10}**	**PM_{10}**	**SO_2**	**SO_2**
	hours/yr	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Without duct burning	6,760	23.1	78.1	14.08	47.6	5.64	19.1	24.0	81.1	1.78	6.02
With duct burning	2,000	29.2	29.2	26.68	26.7	10.2	10.2	36.0	36.0	2.26	2.26
Total	8,760	52.3	**107.4**	40.76	**74.3**	15.84	**29.3**	60.0	**117.1**	4.04	**8.28**
Emissions with SU/SD (includes normal operations and offline period associated with SU/SD [(a)]			87.6		252.7		34.2		n/a		n/a
Maximum Annual Emissions			**107.4**		**252.7**		**34.2**		**117.1**		**8.28**

(a) See Table A-4

Table C-4 Maximum Annual Emissions with Startups and Shutdowns

Start-up, Shutdown and Offline Events / Hours (Each Turbine)

Operating Mode	Number	Duration (SU/SD)		Offline		NO_x	CO
	of Events/yr	hr/event	hr/yr	hr/event	hr/yr	lb/stack	lb/stack
hot / warm start	260	1.3	347	6	1560	40	329
cold start	50	1.8	92	48	2400	96	410
shutdown	310	0.5	155	n/a	n/a	57	337
TOTALS			**593**		**3960**		

NOx, CO, and VOC lb/stack emission rates are based on GE guarantees

Annual NO_x Emissions with Start-up and Shutdown (Two Turbines)

Operating Mode	NO_x			
	hr/yr	lb/hr/turbine	total lb/hr	tpy
without duct burning	2,207	11.6	23.1	25.5
with duct burning	2,000	14.6	29.2	29.2
hot / warm start	347	30.0	60.0	10.4
cold start	92	52.4	104.7	4.8
shutdown	155	114.0	228.0	17.7
TOTALS	**4,800**	**223**	**445**	**88**

Annual CO Emissions with Start-up and Shutdown (Two Turbines)

Operating Mode	CO			
	hr/yr	lb/hr/turbine	total lb/hr	tpy
without duct burning	2,207	7.04	14.08	15.5
with duct burning	2,000	13.3	26.7	26.7
hot / warm start	347	247	494	85.5
cold start	92	224	447	20.5
shutdown	155	674	1,348	104.5
TOTALS	**4,800**	**1,165**	**2,330**	**253**

Annual VOC Emissions with Start-up and Shutdown (Two Turbines)

Operating Mode	VOC			
	hr/yr	lb/hr	total lb/hr	tpy
without duct burning	2,207	2.82	5.6	6.2
with duct burning	2,000	5.10	10.2	10.2
hot / warm start	347	21	42.0	7.3
cold start	92	17	33.8	1.6
shutdown	155	58	116.0	9.0
TOTALS	**4,800**	**104**	**208**	**34.24**

Table C-5 Emissions from Natural Gas Fired Auxiliary Boiler

	Emission Factor [3] (lb/10^6 scf)	Emission Factor [3] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)
NO_x [1]	---	0.011	0.385	0.0963
VOC	5.50	0.005	0.188	0.0470
CO [1]	---	0.074	2.590	0.6475
SO_2 [2]	0.60	0.0006	0.021	0.0051
PM_{10} Total	7.60	0.007	0.260	0.0649
Lead	5.00E-04	4.88E-07	1.71E-05	4.27E-06

Notes

1 - Assumes 9 ppmvd NO_x and 100 ppmvd CO at 3% O_2 with low NO_x burners.

2 - Assumes 0.2 grains Sulfur/100 scf natural gas

3 - From AP42 - Table 1.4-1 and Table 1.4-2

Maximum annual operation 500 hr/yr

Boiler Heat Input 35 MMBtu/hr

Heating Value NG 1,024 Btu/scf

Table C-6 Emissions from Natural Gas Fired HTF Heater

Pollutant	Emission Factor [3] (lb/10^6 scf)	Emission Factor [3] (lb/MMBtu)	Emission Rate (lb/hr)	Emission Rate (tpy)
NO_x [1]	---	0.011	0.440	0.220
VOC	5.5	0.005	0.215	0.107
CO [1]	---	0.074	2.960	1.480
SO_2 [2]	0.6	0.0006	0.023	0.012
PM_{10} Total	7.6	0.007	0.297	0.148
Lead	5.00E-04	4.88E-07	1.95E-05	9.77E-06

Notes

1 - Assumes 9 ppmvd NO_x and 100 ppmvd CO at 3% O_2 with low NO_x burners.

2 - Assumes 0.2 grains Sulfur/100 scf natural gas

3 - From AP42 - Table 1.4-1 and Table 1.4-2

Maximum annual operation		**1,000**	**hr/yr**
Boiler Heat Input		**Heating Value NG**	
40	**MMBtu/hr**	**1,024**	**Btu/scf**

Table C-7 Emissions from Emergency Diesel Generator

Emission estimates per Emergency Diesel Generator

Diesel engine output:	2,682	hp		2.0	MW
Diesel engine output:	6.82	MMBtu/hr			
Diesel engine input:	19.45	MMBtu/hr	Vendor data		
Maximum Annual Hours of Operation:	50	hours/year			
Stack Height:	30	feet	assumption		
Stack Diameter	1.79	feet			
Stack Flow Rate:	15,136	cfm	Vendor data		
Stack Gas Exit Temperature:	761.7	F	Vendor data		
Stack Gas Exit Velocity:	100.00	ft/s	assumption		

Pollutant	Emission Factor	Units	Hourly Emissions			Annual Emissions	
			(lb/hr)	(g/hp-hr)	(g/s)	(ton/yr)	(g/s)
NO_x			26.79	4.53	3.38	0.67	0.019
VOC			1.41	0.24	0.18	0.04	0.0010
CO			15.42	2.61	1.94	0.39	0.0111
SO_2	0.0015	percent by wt.	0.029	0.0050	0.0037	0.0007	0.00002
PM_{10} total			0.89	0.150	0.1118	0.0222	0.0006
Lead	9.E-06	lb/MMBtu	2.E-04	3.E-05	2.E-05	4.E-06	1.E-07

Sulfur Content of Fuel %	0.0015

NOTES:

1. The emission factor for SO2 is 1.01 times the sulfur content of the fuel. AP-42 Table 3.4-1 (10/96)
2. Emissions factors for Pb similar to BACT for recent permits (Steag Project). Remaining from Caterpillar.

Table C-8 Emissions from Firewater Pump Diesel Engine

Emission Estimates For Fire Water Pump

Diesel engine output:	182	hp	1.341 hp/kW
Diesel engine output:	0.46	MMBtu/hr	1hp = 2544 Btu/hr
Diesel engine input:	1.32	MMBtu/hr	
Maximum Annual Hours of Operation:	50	hours/year	
Stack Height:	30	feet	assumption
Stack Diameter	0.47	feet	
Stack Flow Rate:	1,027	cfm	Scaled from EDG (2682 hp)
Stack Gas Exit Temperature:	761.7	F	
Stack Gas Exit Velocity:	100.00	ft/s	assumption

Pollutant	Emission Factor	Units	Hourly Emissions			Annual Emissions	
			(lb/hr)	(g/hp-hr)	(g/s)	(ton/yr)	(g/s)
NO_x			1.14	2.83	0.14	0.03	0.001
VOC			0.06	0.15	0.01	0.00	0.0000
CO			1.05	2.61	0.13	0.03	0.001
SO_2	0.0015	percent by wt.	0.002	0.005	0.0003	0.0000	0.0000014
PM_{10} total			0.060	0.150	0.008	0.00150	0.00004
Lead	9.E-06	lb/MMBtu	1.E-05	3.E-05	1.E-06	3.E-07	9.E-09

Sulfur Content of Fuel	0.0015

NOTES:

1. The emission factor for SO2 is 1.01 times the sulfur content of the fuel. AP-42 Table 3.4-1 (10/96)
2. Emissions factors for Pb similar to BACT for recent permits (Steag Project). Remaining from Caterpillar.
3. 182 hp per email dated june 30th from Russ Kingsley to Sara Head

Table C-9 Cooling Tower Particulate Matter Emissions Estimates

Parameter	Units	Value
Water Circulation Rate	gpm	130,000
Total Liquid Drift	(%)	0.00050
Maximum TDS of Circulated Water	(ppmw)	5,000
Emission Rate - Total Cooling Tower		
TSP	lb/hr	1.63
	ton/yr	7.13
PM_{10}	lb/hr	0.81
	ton/yr	3.56

NOTES:

1. TSP Emission Rate = based on USEPA AP-42, Section 13.4 Wet Cooling Towers, Table 13.4-1, modified to design

   Rates calculated as follows:

   E lb/hr = Water Circulation Rate gpm * 60 min/hr * Drift % / 100 * 8.3453 lb/gal * TDS lb PM / 1,000,000 lb water

   E ton/yr = E lb/hr * 8,760 hr/yr * ton/2,000 lb

2. PM_{10} calculated from TSP, assumes 50% of TSP

Table C-10 Hazardous Air Pollutant Emission Estimates - Summary of All Operational Sources

Pollutant	CAS Number	Emissions (total)		
		(lbs/hr)	(lbs/yr)	(tons/yr)
1,3-Butadiene	106990	1.97E-03	1.73E+01	8.63E-03
Acetaldehyde	75070	1.84E-01	1.61E+03	8.03E-01
Acrolein	107028	2.95E-02	2.57E+02	1.29E-01
Arsenic	7440382	2.94E-06	8.18E-03	4.09E-06
Benzene	71432	5.54E-02	4.82E+02	2.41E-01
Benzo(a)anthracene	56553	3.48E-04	3.05E+00	1.52E-03
Benzo(a)pyrene	50328	2.14E-04	1.88E+00	9.38E-04
Benzo(b)fluoranthene	205992	1.74E-04	1.52E+00	7.62E-04
Benzo(k)fluoranthene	207089	1.69E-04	1.48E+00	7.42E-04
Beryllium	7440417	1.07E-06	9.41E-03	4.71E-06
Chloroform	67663	2.12E-05	2.69E-02	1.35E-05
Chrysene	218019	3.88E-04	3.40E+00	1.70E-03
Cyanide compounds	1073	8.03E-09	4.69E-05	2.34E-08
Dibenz(a,h)anthracene	53703	3.62E-04	3.17E+00	1.59E-03
Ethylbenzene	100414	1.47E-01	1.29E+03	6.43E-01
Formaldehyde	50000	3.26E-01	2.85E+03	1.43E+00
Hexane	110543	3.38E-04	1.80E-01	9.02E-05
Indeno(1,2,3-cd)pyrene	193395	3.62E-04	3.17E+00	1.59E-03
Naphthalene	91203	5.98E-03	5.22E+01	2.61E-02
p-Dichlorobenzene	106467	3.78E-06	1.10E-02	5.52E-06
PAH's (excluding naphthalene)	1151	2.94E-05	1.57E-02	7.84E-06
Perchloroethylene {tetrachloroethene}	127184	1.66E-08	1.46E-04	7.28E-08
Phenol	108952	6.04E-08	5.29E-04	2.65E-07
Propylene Oxide	75569	1.33E-01	1.16E+03	5.82E-01
Selenium	7782492	2.94E-06	1.36E-02	6.82E-06
Toluene	108883	5.98E-01	5.22E+03	2.61E+00
Trichloroethylene	79016	7.55E-10	6.62E-06	3.31E-09
Xylenes (mixed xylenes)	1330207	2.95E-01	2.57E+03	1.29E+00
Grand Total		**1.8**	**15,524.9**	**7.8**

Table C-11 Hazardous Air Pollutant Emission Estimates - Operational Turbines

Assumptions:	H18U	18 F/60%RH
	2	Turbines + Duct Burners
Operating Schedule	8760	hours/year
Gas Heat Content	1020	MMBtu/MMscf
CTG Heat Input:	3,473	MMBtu/Hr (HHV Total)
DB Heat Input:	1,111	MMBtu/Hr (HHV Total)
Total Heat Input:	4,584	MMBtu/Hr (Total)

Natural Gas Fuel Rate (each)			
Hourly		Annual	
1.70	MMscf/hou	1,736	MMscf/year
0.54	MMscf/hou	555	MMscf/year
2.25	MMscf/hou	2,292	MMscf/year

Substance	CAS Number	Emission Factor (1) (lbs/MMBtu)	Emission Factor (lbs/MMscf)	Gas Input (MMscf/hr)	Emissions (each)			Emissions (total)		
					(lbs/hr)	(lbs/yr)	(tons/yr)	(lbs/hr)	(lbs/yr)	(tons/yr)
Acetaldehyde	75070	4.00E-05	4.08E-02	2.25	9.17E-02	8.03E+02	4.02E-01	1.83E-01	1.61E+03	8.03E-01
Acrolein	107028	6.40E-06	6.53E-03	2.25	1.47E-02	1.28E+02	6.42E-02	2.93E-02	2.57E+02	1.28E-01
Benzene	71432	1.20E-05	1.22E-02	2.25	2.75E-02	2.41E+02	1.20E-01	5.50E-02	4.82E+02	2.41E-01
1,3-Butadiene	106990	4.30E-07	4.39E-04	2.25	9.85E-04	8.63E+00	4.32E-03	1.97E-03	1.73E+01	8.63E-03
Ethylbenzene	100414	3.20E-05	3.26E-02	2.25	7.33E-02	6.42E+02	3.21E-01	1.47E-01	1.28E+03	6.42E-01
Formaldehyde (2)	50000	7.10E-05	7.24E-02	2.25	1.63E-01	1.43E+03	7.13E-01	3.25E-01	2.85E+03	1.43E+00
Naphthalene	91203	1.30E-06	1.33E-03	2.25	2.98E-03	2.61E+01	1.30E-02	5.96E-03	5.22E+01	2.61E-02
Benzo(a)anthracene (3)	56553		7.75E-05	2.25	1.74E-04	1.52E+00	7.62E-04	3.48E-04	3.05E+00	1.52E-03
Benzo(a)pyrene (3)	50328		4.76E-05	2.25	1.07E-04	9.38E-01	4.69E-04	2.14E-04	1.88E+00	9.38E-04
Benzo(b)fluoranthene (3)	205992		3.87E-05	2.25	8.70E-05	7.62E-01	3.81E-04	1.74E-04	1.52E+00	7.62E-04
Benzo(k)fluoranthene (3)	207089		3.77E-05	2.25	8.47E-05	7.42E-01	3.71E-04	1.69E-04	1.48E+00	7.42E-04
Chrysene (3)	218019		8.64E-05	2.25	1.94E-04	1.70E+00	8.50E-04	3.88E-04	3.40E+00	1.70E-03
Dibenz(a,h)anthracene (3)	53703		8.06E-05	2.25	1.81E-04	1.59E+00	7.93E-04	3.62E-04	3.17E+00	1.59E-03
Indeno(1,2,3-cd)pyrene (3)	193395		8.06E-05	2.25	1.81E-04	1.59E+00	7.93E-04	3.62E-04	3.17E+00	1.59E-03
Propylene Oxide	75569	2.90E-05	2.96E-02	2.25	6.65E-02	5.82E+02	2.91E-01	1.33E-01	1.16E+03	5.82E-01
Toluene	108883	1.30E-04	1.33E-01	2.25	2.98E-01	2.61E+03	1.30E+00	5.96E-01	5.22E+03	2.61E+00
Xylene (Total)	1330207	6.40E-05	6.53E-02	2.25	1.47E-01	1.28E+03	6.42E-01	2.93E-01	2.57E+03	1.28E+00

(1) Emission factors are from AP-42 Section, Table 3.1-3 Emission factors for HAP's from natural gas-fired stationary gas turbines.

(2) Formaldehyde AP-42 emission factor adjusts for 90% emissions control usinig carbon monoxide catalyst.

(3) Unspeciated PAH (polycyclic aromatic hydrocarbon) emissions based on AP-42 composite emission factor of 2.20E-06 lbs/MMBtu. PAH speciation profile derived from California Air Toxics Emission Factors (CATEF) database for natural gas-fired turbine engines, applied to composite (unspeciated) PAH emission in AP-42. Shown are PAH species for which there is a unit risk factor in OEHHA Consolidated Risk Table (OEHHA, October 2006)

Table C-12 Hazardous Air Pollutant Emission Estimates - Cooling Towers

Cooling Tower Recirculation Rate: 130,000 gpm
Drift Eliminator Efficiency: 0.0005 %
Drift: 325.5 lbs/hr (E lb/hr = Water Circulation Rate gpm * 60 min/hr * Drift % / 100 * 8.3453 lb/gal)
Cooling Tower Cylces of Concentration: 5
Cooling Tower Makeup Rate 3,018 gpm

Emission Rate for Non-Volatile Compounds: ER (lb/hr) = Recirculation rate (gal/min) * 60 min/hr * 3.785 liters/gal * HAP conc (ug/liter) * 1lb / 453.6 g * 1g / 10^6 ug * Drift Fraction * 4000/973 (5 conc cycles)

Emission Rate for Volatile Compounds: ER (lb/hr) = Makeup rate (gal/min) * 60 min/hr * 3.785 liters/gal * HAP conc (ug/liter) * 1lb / 453.6 g * 1g / 10^6 ug * Volatilization Fraction (assumed to be one)

Substance	CAS Number	Reported Discharge [1]		Emissions (per unit) [2]		Emissions (total)	
		Average Dischange (ug/l)	Maximum Discharge (ug/l)	Max Hourly (lbs/hr/unit)	Annual (lbs/yr/unit)	Max Hourly (lbs/hr)	Annual (lbs/yr)
Emission Rate for Non-Volatile Compounds:							
Arsenic	7440382	6.98E-03	2.20E-02	2.943E-07	8.18E-04	2.94E-06	8.18E-03
Beryllium	7440417	8.03E-03	8.03E-03	1.075E-07	9.41E-04	1.07E-06	9.41E-03
Cyanide compounds	1073	4.00E-05	6.00E-05	8.027E-10	4.69E-06	8.03E-09	4.69E-05
Selenium	7782492	1.16E-02	2.20E-02	2.943E-07	1.36E-03	2.94E-06	1.36E-02
Emission Rate for Volatile Compounds:							
p-Dichlorobenzene	106467	8.34E-04	2.50E-03	3.777E-07	1.10E-03	3.78E-06	1.10E-02
Chloroform	67663	2.04E-03	1.40E-02	2.115E-06	2.69E-03	2.12E-05	2.69E-02
Perchloroethylene {tetrachloroethene}	127184	1.10E-05	1.10E-05	1.662E-09	1.46E-05	1.66E-08	1.46E-04
Trichloroethylene	79016	5.00E-07	5.00E-07	7.555E-11	6.62E-07	7.55E-10	6.62E-06
Toluene	108883	7.78E-04	7.78E-04	1.176E-07	1.03E-03	1.18E-06	1.03E-02
Xylenes (mixed xylenes)	1330207	7.60E-04	7.60E-04	1.148E-07	1.01E-03	1.15E-06	1.01E-02
Phenol	108952	4.00E-05	4.00E-05	6.044E-09	5.29E-05	6.04E-08	5.29E-04

(1) Based on water quality data obtained from the Victor Valley Water Reclamation Authority for 2004 and 2005.

Table C-13 Hazardous Air Pollutant Emission Estimates - Natural Gas Fired Auxiliary Boiler

Input:	35.00	MMBtu/Hr
Maximum Annual Hours of Operation:	500	hours/year
Heat Value:	1020	Btu/scf

Substance	CAS Number	Emission Factor [1] (lbs/MMscf)	Max Hourly Emissions (lb/hr)	Annual Emissions	
				(lb/yr)	(ton/yr)
Benzene	71432	0.0058	1.99E-04	0.09951	4.98E-05
Formaldehyde	50000	0.0123	4.22E-04	0.00011	2.11E-01
PAH's (excluding naphthalene) [(2)]	1151	0.0004	1.37E-05	0.00000	6.86E-03
Naphthalene	91203	0.0003	1.03E-05	0.00000	5.15E-03
Acetaldehyde	75070	0.0031	1.06E-04	0.00003	5.32E-02
Acrolein	107028	0.0027	9.26E-05	0.00002	4.63E-02
Toluene	108883	0.0265	9.09E-04	0.00023	4.55E-01
Xylenes	1330207	0.0197	6.76E-04	0.00017	3.38E-01
Ethyl benzene	100414	0.0069	2.37E-04	0.00006	1.18E-01
Hexane	110543	0.0046	1.58E-04	0.00004	7.89E-02

[(1)] Emission factors based on Ventura County Air Pollution Control District, AB2588 Combustion Emission Factors for Natural Gas Fired External Combustion Equipment 10-100 MMBtu/Hr, May 2001

[(2)] Unspeciated PAH (polycyclic aromatic hydrocarbon) emissions based on composite emission factor. Benzo(a)pyrene or B(a)P was modeled as the surrogate carcinogen for all PAH emissions, as indicated by the CAS number shown. Since the (B(a)P) surrogate for total PAH emissions is the most or nearly-the-most potent carcinogens in the class, use of this cancer potency factor with total emissions will overestimate the risk.

Table C-14 Hazardous Air Pollutant Emission Estimates - Natural Gas Fired HTF Heater

Input:	40.00	MMBtu/Hr
Maximum Annual Hours of Operation:	1,000	hours/year
Heat Value:	1020	Btu/scf

Substance	CAS Number	Emission Factor [1] (lbs/MMscf)	Max Hourly Emissions (lb/hr)	Annual Emissions	
				(lb/yr)	(ton/yr)
Benzene	71432	0.0058	2.27E-04	2.27E-01	1.14E-04
Formaldehyde	50000	0.0123	4.82E-04	4.82E-01	2.41E-04
PAH's (excluding naphthalene) [(2)]	1151	0.0004	1.57E-05	1.57E-02	7.84E-06
Naphthalene	91203	0.0003	1.18E-05	1.18E-02	5.88E-06
Acetaldehyde	75070	0.0031	1.22E-04	1.22E-01	6.08E-05
Acrolein	107028	0.0027	1.06E-04	1.06E-01	5.29E-05
Toluene	108883	0.0265	1.04E-03	1.04E+00	5.20E-04
Xylenes	1330207	0.0197	7.73E-04	7.73E-01	3.86E-04
Ethyl benzene	100414	0.0069	2.71E-04	2.71E-01	1.35E-04
Hexane	110543	0.0046	1.80E-04	1.80E-01	9.02E-05

[(1)] Emission factors based on Ventura County Air Pollution Control District, AB2588 Combustion Emission Factors for Natural Gas Fired External Combustion Equipment 10-100 MMBtu/Hr, May 2001

[(2)] Unspeciated PAH (polycyclic aromatic hydrocarbon) emissions based on composite emission factor. Benzo(a)pyrene or B(a)P was modeled as the surrogate carcinogen for all PAH emissions, as indicated by the CAS number shown. Since the (B(a)P) surrogate for total PAH emissions is the most or nearly-the-most potent carcinogens in the class, use of this cancer potency factor with total emissions will overestimate the risk.

Appendix D

Modeling Archive