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Document Title:	Petition to Amend - Reduce PM10 and SO2 Emissions 08-18-2015
Description:	Blythe Energy Project - Petition to Amend - Reduce PM10 and SO2 Emissions 08-18-2015
Filer:	Mary Dyas
Organization:	Blythe Energy, Inc.
Submitter Role:	Applicant
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Blythe Energy Inc.

1411 Third Street, Suite A main (810) 887-4726
Port Huron, MI 48060 fax (810) 887-4756

August 18, 2015

Ms. Mary Dyas, Compliance Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Blythe Energy Project (99-AFC-08C)
Petition to Amend

Dear Ms. Dyas:

Enclosed please find a Petition to Amend (PTA) for the Blythe Energy Project (99-AFC-08C). This PTA addresses proposed reductions to the hourly and annual particulate matter (PM10) mass emission limits, a reduction of the annual natural gas fuel sulfur content limit, and a reduction of the annual sulfur dioxide (SO_2) mass emission limit. The proposed reductions in permitted annual PM_{10} mass emissions will be used as simultaneous emissions reductions at this stationary source. Under Mojave Desert Air Quality Management District regulations, these reductions in PM_{10} can only be used to offset simultaneous increases, and therefore could not be included in the February 2015 petition to amend for the Project.

The amendment proposed by this petition would modify four Conditions of Certification (COC) to make them consistent with the proposed changes to the Mojave Desert Air Quality Management District (MDAQMD) permits. However, the proposed amendment would not result in any environmental impacts or inconsistency with any Laws, Ordinances, Regulations, or Standards (LORS). In fact, approval of the amendment will ensure that emissions from the BEP project remain below those evaluated in the original licensing proceeding.

If you have any questions or require additional information regarding the proposed emission reductions, please do not hesitate to contact Gary Rubenstein of Sierra Research at (916) 273-5126.

Sincerely,

Christopher J. Doyle
Vice President

Enclosure
cc: Ms. Melissa A. Foster, Stoel Rives LLP
Mr. Gary Rubenstein, Sierra Research

sierra research

Petition to Amend Blythe Energy Project (99-AFC-08C)

prepared for:

Blythe Energy Inc.

submitted to:

California Energy Commission

August 2015

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95811
(916) 444-6666

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Petition to Amend
Blythe Energy Project

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ACRONYMS AND ABBREVIATIONS

AFC	Application for Certification
BEP	Blythe Energy Project
BEP II	Blythe Energy Project Phase II
CEC	California Energy Commission
CO	carbon monoxide
COC	Condition of Certification
LORS	Laws, Ordinances, Regulations, and Standards
MDAQMD	Mojave Desert Air Quality Management District
MW	megawatt
NO_x	oxides of nitrogen
$PM_{2.5}$	fine particulate matter
PM_{10}	respirable particulate matter
PTE	potential to emit
SEP	Sonoran Energy Project
SO_2	sulfur dioxide

1. INTRODUCTION

1.1 Background

Blythe Energy Project (BEP or Project) is a nominal 520-megawatt (MW) combined-cycle power plant located in the City of Blythe, north of Interstate 10 and approximately 7 miles west of the California/Arizona border. The California Energy Commission (CEC) issued a license for Blythe Energy Inc.'s (Blythe Energy) BEP on March 21, 2001. Commercial operations for the plant began in July 2003.

The purpose of this proposed amendment is to reduce hourly and annual particulate matter (PM_{10})[1] mass emission limits, reduce the annual natural gas fuel sulfur content limit, and reduce the annual sulfur dioxide (SO_2) mass emission limit from the overly conservative emission limits required within the license to more accurately reflect potential emissions from the facility. The proposed reductions in permitted annual PM_{10} mass emissions at BEP will be used to offset the PM_{10} emissions increases from AltaGas' proposed Sonoran Energy Project (02-AFC-01C, TN#205652). Under Mojave Desert Air Quality Management District (District) regulations, the reductions in PM_{10} can only be used to offset emissions increases that occur simultaneously—that is, as part of the same permitting action by the District. The PM_{10} reductions that are being proposed in this petition to amend could not be included in the February 2015 petition to amend for BEP because the air permit application for SEP had not yet been filed. Now that the air permit application for SEP has been filed (TN#205687), the District will process both the BEP and SEP amendments simultaneously and this BEP petition for emissions reductions is timely.

In November 2014 (TN#203374), a project modification was submitted by Blythe Energy to add a turndown upgrade package to the two turbines. This upgrade allows the turbines to operate at a lower minimum load, thereby reducing fuel use and emissions during minimum load operation. The turndown upgrade was approved as a staff amendment in January 2015 (TN#203503). In February 2015 (TN#203667), a petition to amend was submitted by the project owner to reduce BEP's annual emissions of NOx, CO, and $PM_{10}/PM_{2.5}$ so that the facility would no longer be considered a major stationary source under federal Prevention of Significant Deterioration regulations.[2] The modification was approved by the full Commission in July 2015 (TN#205378).

[1] All PM_{10} from the gas turbines is assumed to be in the $PM_{2.5}$ size range, so all references to PM_{10} include $PM_{2.5}$ as well.

[2] Because both BEP and the adjacent Sonoran Energy Project (formerly BEP Phase II) are under the common control of AltaGas Power Holdings (U.S.), the two facilities are considered a single stationary source under Mojave Desert Air Quality Management District regulations.

The PM_{10} emission limits in the current BEP license were approved based on conservative emissions guarantees provided by Siemens, the gas turbine manufacturer. Based on over ten years of operating experience and refined PM test methods, BEP has determined that the hourly and annual mass emission limits for PM_{10} in the original license were overly conservative and actual emissions are significantly below the annual limits.

The annual mass emission limits for SO_2 were derived over ten years ago using an assumed natural gas fuel sulfur content of 0.5 grains per 100 standard cubic feet (gr/scf). However, more recently licensed projects, including the adjacent Blythe Energy Project II (BEP II),[3] have assumed a significantly lower annual average sulfur content (in the range of <0.1 gr/scf to 0.25 gr/scf). By using the currently licensed 0.5 gr/scf sulfur content, BEP's SO_2 annual permit limits are overly conservative and actual emissions are well below the permitted limit.

The proposed changes will reduce the facility potential to emit (PTE) for SO_2 and PM_{10} as well as reported annual emissions from BEP, but will not have any effect on actual emissions. No change in annual fuel consumption will result from this amendment, and therefore there would be no change in greenhouse gas emissions as a result of the proposed amendment.

The amendment proposed by this petition would modify four Conditions of Certification (COC) to make them consistent with the proposed changes to the Mojave Desert Air Quality Management District (MDAQMD) permits. However, the proposed amendment would not result in any environmental impacts or inconsistency with any Laws, Ordinances, Regulations, or Standards (LORS). In fact, approval of the amendment will ensure that emissions from the BEP project remain below those evaluated in the original licensing proceeding.

An application for changes to the facility air permits has been submitted to the MDAQMD. A copy of the application is provided as Appendix A.

1.2 Description of Proposed Amendment

Consistent with Sections 1769(a)(1)(A) and (B) of the Siting Regulations, this section includes a complete description of the proposed change as well as the necessity for the change.

BEP is composed of two Siemens F Class V84.3A (2) gas turbines with duct-fired heat recovery steam generators, a single condensing steam turbine, two wet cooling towers, and associated plant equipment. Since BEP commenced commercial operation in 2003, there have been major advances in PM_{10} emissions testing procedures that have improved the accuracy of PM_{10} testing and resulted in extremely low PM_{10} emission rates from natural gas fired gas turbines. Additionally since BEP began operating, natural gas fuel sulfur content has been determined to be significantly lower than what was originally licensed at BEP. As natural gas fuel sulfur content is used to determine SO_2 emissions, a reduction in the sulfur fuel content will result in decreased SO_2 annual emissions and a reduced SO_2 emission limit.

[3] A Petition to Amend (TN# 205652) was filed on August 7, 2015, for the BEP II. As part of the amendment, the project is now referred to as the Sonoran Energy Project or SEP.

The purpose of this proposed amendment is to reduce the overly conservative hourly and annual PM_{10} mass emission limits, the fuel gas sulfur content, and the annual SO_2 mass emission limit from that currently licensed, resulting in lower emission limits for BEP. The proposed reductions in permitted annual PM_{10} emissions will be used as simultaneous emissions reductions at this stationary source, while the reduction in annual SO_2 is intended to reduce the facility-wide SO_2 PTE.

The proposed amendment will have no additional impacts beyond those identified in the Commission Decision and subsequent amendments to the BEP license. No increases in emissions or other environmental impacts will result from the proposed changes. In fact, implementation of the amendment will ensure that PM_{10} and SO_2 emissions from the plant are maintained at levels lower than originally licensed. Emissions from the BEP project will remain well below those evaluated in the original licensing proceeding.

1.3 Necessity of Proposed Changes

Sections 1769 (a)(1)(B) and (C) of the CEC Siting Regulations (20 Cal. Code Reg. §§ 1701 et seq.) require a discussion of the necessity for the proposed changes to the Project and a discussion of whether this amendment is based on information that was known by the petitioner during the certification proceeding.

Blythe Energy is requesting this change because the hourly and annual PM_{10} emission limits in the original BEP license were based on conservative emission limit guarantees provided by the turbine manufacturer, Siemens, as Blythe Energy did not have actual emission test results information during the certification proceeding. It has since been determined that the turbine manufacturer's emissions guarantees were overly conservative. Blythe Energy now has sufficient operating experience and test data to propose the new, lower PM_{10} limits. Additionally, since BEP has been licensed, a lower maximum annual average natural gas fuel sulfur content has been permitted at other facilities under the CEC's jurisdiction, including the adjacent BEP II. As BEP's annual SO_2 emission limit is based on a higher annual average natural gas fuel sulfur content, SO_2 emission limits are overestimated and conservative. Therefore, Blythe Energy is requesting a lower annual average natural gas sulfur fuel content to reflect current conditions, which in turn lowers BEP's SO_2 PTE. As discussed in more detail in Section 2.1.3, these reductions in emissions can be used to reduce the offset liability associated with emissions increases that will result from the proposed modifications at the adjacent SEP.

These proposed new, lower limits are based on actual operating experience and will more accurately reflect the actual emissions from the gas turbines.

1.4 Summary of Environmental Impacts

Section 1769 (a)(1)(E) of the CEC Siting Regulations requires that an analysis be conducted to address impacts that the proposed revision may have on the environment and proposed measures to mitigate significant adverse impacts. Section 1769 (a)(1)(F) requires a discussion of the impacts of proposed revisions on the facility's ability to comply with applicable LORS.

The proposed changes referenced in this Petition will not result in any additional impacts beyond those already analyzed in the Commission Decision and subsequent amendments or the Final Determination of Compliance. Section 2.0 discusses the potential impacts of the proposed changes on the environment, as well as the consistency of the proposed revision with LORS.

1.5 Consistency of Amendment with License

Section 1769 (a)(1)(D) of the CEC Siting Regulations requires a discussion of the consistency of each proposed project revision with the assumptions, rationale, findings, or other basis of the Commission Decision and whether the revision is based on new information that changes or undermines the bases of the Commission Decision. Also required is an explanation of why the change should be permitted.

The proposed amendment does not undermine the assumptions, rationale, findings, or other basis of the Commission Decision for the Project or subsequent approved amendments. The proposed amendment will ensure that BEP maintains its emissions at levels well below the approved limits, thereby keeping air quality impacts below those previously analyzed. The proposed amendment will have no additional impacts beyond those analyzed in the Commission Decision and subsequent amendments.

2. ENVIRONMENTAL ANALYSIS OF THE PROJECT CHANGES

Blythe Energy has reviewed the amendment proposed herein to determine whether the change will result in any environmental impacts that were not analyzed by the CEC when it previously approved the Project and subsequent amendments.

The following disciplines will not be affected by the proposed change in this amendment and are not addressed below: Facility Design, Efficiency, Reliability, Transmission System Engineering, Transmission Line Safety and Nuisance, Biological Resources, Cultural Resources, Geologic Hazards and Resources, Hazardous Materials Handling, Land Use, Noise, Paleontological Resource, Socioeconomics, Soils, Traffic and Transportation, Visual Resources, Waste Management, Water Resources, Worker Safety and Fire Protection. In addition, although Air Quality-related amendments typically have the potential to affect Public Health impacts, the proposed revised emission limits are reduced from those originally licensed and impacts will be reduced from those previously analyzed; therefore, Public Health is not addressed further. The only discipline that could be affected by the proposed amendment is Air Quality, which is discussed in detail below.

As detailed below, the proposed amendment does not cause significant impacts in any disciplines beyond those previously analyzed.

2.1 Air Quality

Blythe Energy proposes to reduce the hourly and annual PM_{10} emissions limits and the annual SO_2 mass emission limit.

The proposed changes in emissions limits will not involve any physical changes to or changes in the method of operation of the gas turbines, since the turbines are already achieving these lower emission rates. Since the proposed amendment will reduce the hourly and annual PM_{10} emission limits, the annual natural gas sulfur content, and the annual SO_2 mass emission limit, minor edits to COCs AQ-T2, AQ-T4, AQ-T6 and AQ-T7 are necessary.

The permit amendment application to the Mojave Desert Air Quality Management District is provided as Appendix A.

2.1.1 Hourly and Annual PM_{10} Emissions

When the turbines were originally permitted in 2000, gas turbine manufacturers had limited PM emissions test data from in-use gas turbines. The test data available showed significant variation in PM emission rates because of variability in source test conditions and procedures. Therefore, PM emissions guarantees provided by gas turbine manufacturers were relatively high. However, refinements in PM test methods and improved quality control procedures have significantly reduced the variability in PM test results and have improved the accuracy of PM testing at low concentrations.[4] PM_{10} source tests on the BEP gas turbines demonstrate that PM_{10} emissions are consistently well below the permitted emission rate of 11.5 pounds per hour (lb/hr). As an example, PM_{10} test results from the 2014 annual source testing of the BEP gas turbines are summarized in Table 1 below.

Table 1. PM_{10} Test Results

	PM_{10} Emission Rate, lb/hr			
Unit	**Run 1**	**Run 2**	**Run 3**	**Average**
Unit 1	4.6	1.6	1.5	2.5
Unit 2	2.4	2.7	0.8	1.9

Based on these test results, Blythe Energy is proposing to reduce the hourly PM_{10} limit for each gas turbine at BEP from the current level of 11.5 lb/hr to 6.2 lb/hr. PM_{10} emissions changes for the gas turbines are summarized in Table 2.

Table 2. Emissions Changes: PM_{10} from the BEP Gas Turbines

	Period	
	lb/hr	**lb/day**
Proposed permit limit		
– per unit	6.2	–
– total, both units	–	298.5
Current permit limit		
– per unit	11.5	–
– total, both units	–	565
Net change		
– per unit	(5.3)	–
– total, both units	(10.6)	(266.5)

The proposed reduction in permitted hourly PM_{10} will also reduce annual PTE for PM_{10} from the gas turbines and for the facility as a whole. The derivation of the proposed new facility-wide annual PM_{10} limit is shown in Table 3.

[4] Matis, Craig, Glenn England et al, "Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines," August 20, 2009.

Table 3. Calculation of New Annual PM_{10} Limit for BEP

Emissions Unit	PM_{10} PTE
Gas turbines/HRSGs	54.5[a]
Main cooling tower	2.24
Chiller cooling tower	0.16
Diesel fire water pump	6.7×10^{-3}
Total	56.9

Note:
[a] Annual PTE for gas turbines/HRSGs calculated as 6.2 lb/hr per unit * 2 units * 8760 hrs/yr.

Blythe Energy is proposing to reduce the annual PM_{10} limit to 56.9 tons with compliance to be determined on a 12-month rolling total basis. Table 4 summarizes the proposed reduction in permitted annual PM_{10} emissions. Based on the test results summarized in Table 1, Blythe Energy is confident that facility-wide annual emissions of PM_{10} can be maintained below 56.9 tpy under all future operating conditions.

Table 4. Proposed Reductions in Permitted Annual PM_{10} Emissions

	PM_{10} Permit Limit, tons per year [a]
Proposed permit limit	56.9
Current permit limit	97
Net change	(40.1)

Note:
[a] PM_{10} limits include emissions from the cooling towers.

2.1.2 Annual SO_2 Emissions

The annual SO_2 emission limit for BEP was based on a maximum annual average natural gas fuel sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf). As shown in Table 5, more recently licensed projects, including the adjacent BEP II, have assumed a significantly lower annual average sulfur content in calculating their annual SO_2 potential to emit.

Table 5. Sulfur Content Assumptions for Recent Projects Approved in the Project Area

Project Name	Year Filed/Year Approved	Maximum Annual Average Sulfur Content of Natural Gas
Victorville Hybrid	2007/2008	0.2 gr/100 scf
Genesis Solar	2009/2010	<0.1 gr/100 scf
Abengoa Mojave Solar	2009/2010	0.2 gr/100 scf
Blythe Solar	2009/2012	0.2 gr/100 scf
BEP II	2009/2012	0.25 gr/100 scf

Blythe Energy will maintain the 0.5 gr/100 scf as a short-term limit for BEP (that is, for hourly and daily SO_2 emissions calculations), but proposes a new limit of 0.25 gr/100 scf that will be applicable on an annual average basis. This will reduce BEP's SO_2 annual potential to emit from 24 tpy to 12 tpy.

2.1.3 Simultaneous Emissions Reductions

Blythe Energy was required to surrender emission reduction credits (ERCs) to offset the original permitted emissions of PM from the project. Because the permitted emissions from BEP are being reduced, the offset obligation will also be reduced. District Rule 1305 (B)(2)(b) discusses Actual Emission Reductions generated by simultaneous reductions at a facility:

> *[Actual Emissions Reductions] generated from Federally Enforceable reductions in a Facility's Potential to Emit may be used as Offsets if the [Historic Actual Emissions] for the Facility or Emissions Unit which is proposed for a Federally Enforceable reduction in its Potential to Emit was completely offset in a prior permitting action pursuant to this Regulation.*

While Actual Emission Reductions generated by simultaneous reductions at a facility are not eligible for banking as ERCs, they can be used to reduce the offset liability of a proposed modification. Blythe Energy completely offset the facility's PM_{10} Potential to Emit by providing 103 tons of PM_{10} ERCs prior to commencing construction on the facility.[5] The current facility Potential to Emit is proposed to be reduced by 40.1 tons of PM_{10}, and under Rule 1305(B)(2)(b), this reduction may be used as a simultaneous emissions reduction to offset PM_{10} emissions increases that will result from the adjacent SEP.

2.1.4 Mitigation

No significant impacts beyond those previously described in the Commission Decision and subsequent amendments would result from the approval of this amendment. Therefore, additional mitigation measures beyond those currently required by the Commission are not necessary; however, minor edits to COCs AQ-T2, AQ-T4, AQ-T6 and AQ-T7 are necessary.

2.1.5 Consistency with Laws, Ordinances, Regulations, and Standards

The Commission Decision for BEP found the facility to be in compliance with all applicable LORS. As amended, the BEP will continue to comply with all applicable LORS; the proposed amendments do not alter the conclusions or assumptions in the Commission Decision and subsequent amendments.

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[5] BEP was originally permitted with an annual facility-wide PM_{10} limit of 103 tons. This limit was reduced to 97 tons in the February 2015 amendment, which was approved by the CEC on July 8, 2015.

2.1.6 Conditions of Certification

Consistent with the requirements of the CEC Siting Regulations Section 1769 (a)(1)(A), this section addresses the proposed amendments to the Project's Conditions of Certification.

Blythe Energy proposes to reduce the hourly and annual PM_{10} and annual SO_2 mass emission limits from those identified in the Final Commission Decision and subsequent amendments. The proposed revisions to the Conditions of Certification AQ-T2, AQ-T4, AQ-T6 and AQ-T7 are shown in ~~strikeout~~ and **bold underline** font. Only the modified conditions are shown.

AQ-T2 The turbines shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf **on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf** on a rolling twelve month average basis. The turbines shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

Verification: The project owner shall incorporate into the Quarterly Operations Report either a monthly laboratory analysis showing the fuel sulfur content, a monthly fuel sulfur content report from the fuel supplier(s), or the results from a custom fuel monitoring schedule approved by U.S. EPA for compliance with the fuel monitoring provisions of 40 CFR 60 Subpart GG.

AQ- T4 Emissions from the turbines (including the associated duct burners) shall not exceed the following emission limits at any firing rate, except for CO, NOx and VOC during periods of startup, shutdown and malfunction:

a. Hourly rate, computed every 15 minutes, verified by CEMS and annual compliance tests:
   i. NOx as NO2 — the most stringent of 19.80 lb/hr or 2.5 ppmvd corrected to 15% O2 and averaged over one hour).
   ii. NOx as NO2 — effective May 7, 2016, 2.0 ppmvd corrected to 15% O2 and averaged over a rolling 12 month period.
   iii. CO — the most stringent of 17.5 lb/hr or 4.0 ppmvd corrected to 15% O2 and averaged over 3 hours.
   iv. CO – 10 lb/hr averaged over a rolling 12-month period

b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
   i. VOC as CH4 — 2.9 lb/hr (based on 1 ppmvd corrected to 15% O2).
   ii. SOx as SO2 — 2.7 lb/hr (based on 0.5 grains/100 dscf fuel sulfur).
   iii. PM10 — ~~11.5~~ **6.2** lb/hr.

Verification: The project owner shall submit the following in each Quarterly Operations Report: All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, monthly, total quarterly, total calendar year, and rolling 12-month emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); total monthly and rolling 12-month fuel use in the gas turbines and duct burners; average NO2 concentration and average CO mass emission rate, for all operating periods except during startup, shutdown and malfunction, for each gas turbine and associated duct burner, calculated on a rolling 12-month basis; a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430; operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip; any maintenance to any air pollutant control system (recorded on an as-performed basis); and any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ- T6 Emissions from the turbines, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:

a. NOx — 5762 lb/day, verified by CEMS.
b. CO — 8004 lb/day, verified by CEMS.
c. VOC as CH4 — 239 lb/day, verified by compliance tests and hours of operation in steady-state, pre-mix mode.
d. SOx as SO2 — 130 lb/day, verified by fuel sulfur content and fuel use data.
e. PM10 — ~~565~~ **298.5** lb/day, verified by compliance tests and hours of operation.

Verification: The project owner shall submit the following in each Quarterly Operations Report: All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430; operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip; any maintenance to any air pollutant control system (recorded on an as-performed basis); and any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

AQ-T7 Emissions from all units at this facility, including the cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx —97 tons/year, verified by CEMS.
b. CO —97 tons/year, verified by CEMS.
c. VOC as CH4 — 24 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode.
d. SOx as SO2 — ~~24~~ **12** tons/year, verified by fuel sulfur content and fuel use data.
e. PM10 ~~—97~~ **56.9** tons/year, verified by compliance tests and hours of operation.

These limits shall apply to all emissions from all units at this facility, and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

Verification: The project owner shall submit the following in each Quarterly Operations Report: All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol; a list of maximum hourly, maximum daily, monthly, total quarterly, total calendar year, and rolling 12-month emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol); total monthly and rolling 12-month fuel use in the gas turbines and duct burners; average NO2 concentration and average CO mass emission rate for all operating periods except during startup, shutdown and malfunction for each gas turbine and associated duct burner, calculated on a rolling 12-month basis; a log of all excess emissions, including the information regarding malfunctions/breakdowns required by District Rule 430; operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip; any maintenance to any air pollutant control system (recorded on an as-performed basis); and any permanent changes made in the plant process or production that could affect air pollutant emissions, and when the changes were made.

3. POTENTIAL EFFECTS ON THE PUBLIC AND PROPERTY OWNERS

This section addresses potential effects of the proposed project amendment on nearby property owners, the public, and parties in the application proceeding, pursuant to CEC Siting Regulations (Title 20, CCR, Section 1769 [a][1][I]).

The proposed amendment will not differ significantly in potential effects on nearby property owners, the Public, and Parties to the proceeding beyond those previously analyzed. In fact, the proposed amendment will result in decreased impacts to the surrounding area, and ensure that these impacts do not change over time.

4. LIST OF PROPERTY OWNERS

As required by CEC Siting Regulations Section 1769(a)(1)(H), a list of property owners potentially affected by this amendment is to be provided with this Petition. The list of property owners within 1,000 feet of the project site is provided as Appendix B.

APPENDIX A

Application for a Permit Amendment for the Blythe Energy Project
Provided to the Mojave Desert Air Quality Management District

Application for an Authority to Construct for the Sonoran Energy Project and a Permit Amendment for the Blythe Energy Project

prepared for:

AltaGas Sonoran Energy Inc. and Blythe Energy Inc.

submitted to:

Mojave Desert Air Quality Management District

August 2015

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95811
(916) 444-6666

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Prepared by

Sierra Research, Inc.
1801 J Street
Sacramento, CA 95811
(916) 444-6666

Application for an Authority to Construct for the Sonoran Energy Project and a Permit Amendment for the Blythe Energy Project

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Application for an Authority to Construct for the Sonoran Energy Project and a Permit Amendment for the Blythe Energy Project

1. Introduction

AltaGas Sonoran Energy Project (SEP) is currently permitted as a nominal rated 569-megawatt (MW) combined cycle facility. SEP was acquired from Caithness Blythe II by Altagas Power Holdings (U.S.) Inc. (APHUS) in 2014. SEP was originally permitted by the District in 2004 as the Blythe II Energy Project; Caithness modified the project design to incorporate fast-start combined cycle gas turbine technology and received an amended Authority to Construct (ATC) from the District in 2010. APHUS acquired the project in 2014 and changed the name to SEP. The project was never constructed, although the ATCs remain valid.

Blythe Energy Project (BEP) is a nominal 520-megawatt (MW) combined-cycle power plant, composed of two Siemens F Class V84.3A(2) gas turbines with duct-fired heat recovery steam generators (HRSG), a single condensing steam turbine, two wet cooling towers, and associated plant equipment. Commercial operations for the plant began in July 2003. The District has approved several minor changes at the facility since that time: the installation of oxidation catalysts on the gas turbines in April 2010 and the installation of turndown upgrades in December 2014.[1] The District also approved amendments in May 2015 that reduced allowable annual emissions of oxides of nitrogen (NOx), carbon monoxide (CO), and particulate matter (PM_{10})[2] from BEP so that the potentials to emit for all criteria pollutants from the facility are below 100 tons per year. As a result of the May 2015 amendment, BEP is no longer a major stationary source under federal Prevention of Significant Deterioration (PSD) regulations.

SEP and BEP are located on adjacent parcels in the City of Blythe, north of Interstate 10 and approximately 7 miles west of the California/Arizona border. When Caithness owned the Blythe II Energy Project, the project was under separate ownership from the adjacent BEP. As a result, although both power plants are located on contiguous property, they were permitted as separate stationary sources. Since both BEP and SEP are now under common control through their parent company APHUS, the two facilities are now considered to be a single stationary source under District and federal air permitting regulations. As a result, any proposed changes at SEP must be evaluated as modifications to the existing stationary source.

[1] Installation of the oxidation catalysts and implementation of the turndown upgrades were approved as administrative actions by the California Energy Commission (CEC) staff in April 2010 and January 2015, respectively.

[2] All particulate matter emitted from the gas turbines is assumed to be in the $PM_{2.5}$ size fraction, so all PM_{10} is assumed to be $PM_{2.5}$.

The purpose of this proposed amendment is:

- To replace the permitted equipment at SEP with a single, more efficient GE Frame 7HA.02 combustion turbine and steam turbine, operating in a single shaft configuration, and associated support equipment; and

- To reduce allowable hourly and annual emissions of PM_{10} and annual emissions of sulfur dioxide (SO_2) at BEP. The reduction in annual PM_{10} will be used to provide simultaneous emission reductions for the PM_{10} emissions from SEP, while the reduction in annual SO_2 will keep the total combined SO_2 emissions from BEP and SEP below the 25 ton per year (tpy) offset threshold.

2. Permit Changes

The newly configured SEP will include the following new emissions units:

- One GE 7HA.02 gas turbine, rated at a nominal 350 MW;
- One heat recovery steam generator (HRSG) with duct burners, rated at 222 MMBtu/hr (HHV);
- One 66.3 MMBtu/hr (HHV) auxiliary boiler to improve startup efficiency;
- A nominal 200 MW condensing steam turbine;
- A ten-cell wet mechanical draft cooling tower; and
- One 238 HP diesel-fired emergency fire pump engine.

The SEP design will incorporate air pollution emission controls designed to meet expected District BACT determinations. These controls will include dry low-NOx combustors in the CTG to limit NOx production, selective catalytic reduction (SCR) with aqueous ammonia for additional NOx reduction in the HRSG, and an oxidation catalyst to control CO and toxic air contaminant (TAC) emissions. Fuels to be used will be pipeline specification natural gas in the turbine/HRSG and auxiliary boiler, and California low sulfur diesel fuel in the fire pump engine. Low NOx burners will be incorporated into the HRSG and auxiliary boiler. The cooling tower will be equipped with high-efficiency drift eliminators. Based upon the new project design, the project will result in a net decrease in emissions of all pollutants compared with the previously permitted configuration.

At the same time, BEP is proposing to reduce the allowable PM_{10} emissions from its existing gas turbines to 6.2 pounds per hour per turbine and 56.9 tons per year (facility total) from the current limits of 11.5 pounds per hour and 97 tons per year. BEP will also reduce allowable annual SO_2 emissions from 24 to 12 tons per year by limiting the annual average sulfur content of the natural gas fuel.

The proposed changes in emissions limits for BEP will not involve any physical changes to or changes in the method of operation of the gas turbines, since the turbines are already achieving these lower emission rates. The proposed amendment will reduce the annual SO_2 and PM_{10} mass emission limits to levels that are more consistent with actual facility performance and will ensure that SO_2 and PM_{10} emissions from the plant are maintained at levels lower than originally licensed.

2.1 New Authorities to Construct for SEP

Maximum hourly, daily, and annual emissions for the proposed project are presented in Table 1. A detailed description of the proposed new SEP, as well as detailed emissions calculations, regulatory analysis, air quality impact analysis and screening health risk assessment, is provided in the Petition to Amend filed with the CEC, which is included as Appendix A. Application forms for the new emissions units at SEP are included as Appendix B.

Table 1
Sonoran Facility Emissions

	NOx	SO_2	VOC	CO	PM_{10} / $PM_{2.5}$
Maximum Hourly Emissions, lb/hr	188.1	5.0	12.5	138.4	12.1
Maximum Daily Facility Emissions, lb/day	919.6	120.0	286.0	966.6	298.3
Maximum Annual Facility Emissions, tpy	85.6	8.8	24.2	78.0	40.1

Note: See Section 3.1.4, Appendix A, for details on Sonoran Facility emissions.

tpy = ton(s) per year

2.2 Reductions in Emission Limits at BEP

2.2.1 Hourly PM_{10} Limits for the Gas Turbines

When the BEP turbines were originally permitted in 2000, gas turbine manufacturers had limited PM emissions test data from in-use gas turbines. The test data they did have showed significant variation in PM emission rates because of variability in source test conditions and procedures. Therefore, PM emissions guarantees provided by gas turbine manufacturers were relatively high. However, refinements in PM test methods and improved quality control procedures have significantly reduced the variability in PM test results and have improved the accuracy of PM testing at low concentrations.[3] PM_{10} source tests on the BEP gas turbines demonstrate that PM_{10} emissions are consistently well below the permitted emission rate of 11.5 pounds per hour (lb/hr). As an example, PM_{10} test results from the 2014 annual source testing of the BEP gas turbines are summarized in Table 2 below. A special PM_{10} test program run on Unit 2 in January 2015 showed even lower results: the average of three test runs using EPA Methods 201A/202 was 1.08 lb/hr.[4]

Based on these test results, the owner of BEP is proposing to reduce the hourly PM_{10} limit for each gas turbine from the current level of 11.5 lb/hr to 6.2 lb/hr. PM_{10} emissions changes for the gas turbines are summarized in Table 3.

[3] Matis, Craig, Glenn England et al, "Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines," August 20, 2009.

[4] The report of test results was submitted to the District in May 2015.

Table 2
2014 PM_{10} Test Results, BEP Gas Turbines

	PM_{10} Emission Rate, lb/hr			
Unit	**Run 1**	**Run 2**	**Run 3**	**Average**
Unit 1	4.6	1.6	1.5	2.5
Unit 2	2.4	2.7	0.8	1.9

Table 3
Emissions Changes: PM_{10} from the BEP Gas Turbines

	Period	
	lb/hr	**lb/day**
Proposed permit limit		
– per unit	6.2	–
– total, both units	–	298.5
Current permit limit		
– per unit	11.5	–
– total, both units	–	565
Net change		
– per unit	(5.3)	–
– total, both units	(10.6)	(266.5)

2.2.2 Annual PM_{10} Limit for the Facility

The proposed reduction in permitted hourly PM_{10} will also reduce annual PTE for PM_{10} from the gas turbines and for the facility as a whole. The derivation of the proposed new facility-wide annual PM_{10} limit is shown in Table 4.

Table 4
Calculation of New Annual PM10 Limit for BEP

Emissions Unit	**PM_{10} PTE**
Gas turbines/HRSGs	54.5[a]
Main cooling tower	2.24
Chiller cooling tower	0.16
Diesel fire water pump	$6.7\text{x}10^{-3}$
Total	56.9

Note:
a. Annual PTE for gas turbines/HRSGs calculated as 6.2 lb/hr per unit * 2 units * 8760 hrs/yr. Numbers do not add directly due to rounding.

The project owner is proposing to reduce the annual PM_{10} limit to 56.9 tons with compliance to be determined on a 12-month rolling total basis. Table 5 summarizes the proposed reduction in permitted annual PM_{10} emissions. Based on the test results summarized in Table 2, the project owner is confident that facility-wide annual emissions of PM_{10} can be maintained below 56.9 tpy under all future operating conditions.

Table 5
Proposed Reductions in Permitted Annual PM_{10} Emissions, BEP

	PM_{10} Permit Limit, tons per year [a]
Proposed permit limit	56.9
Current permit limit	97
Net change	(40.1)

Note:
a. PM_{10} limits include emissions from the cooling towers.

2.2.3 Annual SO_2 Emissions

The permitted annual SO_2 emission limit of 24 tpy for BEP was based on a maximum annual average natural gas fuel sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf). As shown in Table 6, more recently licensed projects, including the adjacent BEP II, have assumed a significantly lower annual average sulfur content in calculating their annual SO_2 potential to emit.

Table 6
Fuel Sulfur Content Assumptions for Recent Projects in the Project Area

Project Name	Year Filed / Year Approved	Maximum Annual Average Sulfur Content of Natural Gas
Victorville Hybrid	2007/2008	0.2 gr/100 scf
Genesis Solar	2009/2010	<0.1 gr/100 scf
Abengoa Mojave Solar	2009/2010	0.2 gr/100 scf
Blythe Solar	2009/2010	0.2 gr/100 scf
BEP II (amendment)	2009/2010	0.25 gr/100 scf

The project owner will maintain the 0.5 gr/100 scf as a short-term limit for BEP (that is, for hourly and daily SO_2 emissions calculations), but proposes a new limit of 0.25 gr/100 scf that will apply on an annual average basis. This will reduce BEP's SO_2 annual potential to emit from 24 tpy to 12 tpy.

3. Best Available Control Technology (BACT) and Air Quality Impacts

BACT and air quality impact requirements applicable to SEP are addressed in detail in the SEP PTA (Appendix A).

Because the proposed changes in permitted emission limits reflect emission rates the BEP gas turbines are already achieving, the proposed changes will not result in any real changes in air quality impacts from the facility. Long-term SO_2, PM_{10}, and $PM_{2.5}$ impacts will remain significantly lower than those assessed during the original permit evaluation.

The requirements of Rule 1302 (C)(2)(b) (modeling) and 1303(A) (BACT) for new or modified sources do not apply to the proposed change in permitted emission limits for BEP because the proposed change will not result in a net emissions increase of any regulated air pollutant, and therefore does not meet the definition of "modification."

4. Emission Offsets

Emission offsets are required for increases in emissions of nonattainment pollutants that occur at the facility above MDAQMD offset threshold levels. Because the proposed SEP is considered a modification to the existing BEP, the facility emissions shown in Table 7 below are the sum of permitted emissions at BEP and SEP. Emission increases from the proposed project are also compared with the District offset thresholds in Table 7. Under District Rule 1305(a)(2)(b)(ii)b.II, offsets must be provided for emissions that exceed the threshold amounts in Rule 1303(B).

Blythe Energy was required to surrender emission reduction credits (ERCs) to offset the original permitted emissions of PM from the project. The facility's original PM_{10} Potential to Emit of 103 tons per year was fully offset with PM_{10} ERCs prior to commencement of construction on the facility.[5] As part of this application, the project owner proposes to reduce BEP's Potential to Emit by 40.1 tons of PM_{10}. Under Rule 1305(B)(2)(b), this reduction may be used to create Actual Emissions Reductions, as defined in District Rule 1301:

> *"Actual Emissions Reductions (AERs)" - Emissions reductions which result from modifications to or shutdowns of existing Emissions Unit(s) which have been banked pursuant to District Regulation XIV or which are simultaneous reductions within the same Facility as calculated pursuant to District Rule 1305(B)(2). AERs shall be real, enforceable, quantifiable, surplus and permanent and shall be calculated pursuant to provisions of District Rules 1305(B)(2) or 1404(A) as applicable.*

While Actual Emission Reductions generated by simultaneous reductions at a facility are not eligible for banking as ERCs, they can be used to reduce the offset liability of a proposed contemporaneous modification. The 40.1 tons of PM_{10} AERs that will result from the reduction in annual PM_{10} at BEP may be used as offsets for PM_{10} and PM_{10} precursors (including SOx) under District Rule 1305(B)(2).

> *[Actual Emissions Reductions] generated from Federally Enforceable reductions in a Facility's Potential to Emit may be used as Offsets if the [Historic Actual Emissions] for the Facility or Emissions Unit which is proposed for a Federally Enforceable reduction in its Potential to Emit was completely offset in a prior permitting action pursuant to this Regulation.*

AltaGas Sonoran Energy Inc. also owns 200 tons of NOx ERCs that will be used to provide the remaining required offsets. As required by District rules, these emission offsets will be surrendered to the MDAQMD prior to the initial operation of SEP.

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[5] BEP was originally permitted with an annual facility-wide PM_{10} limit of 103 tons. This limit was reduced to 97 tons in the February 2015 amendment, which was approved by the CEC in July 2015.

Table 7
MDAQMD Nonattainment Pollutant Emission Offset Thresholds (tpy)

Pollutant	Existing BEP Emissions	Proposed Emissions, SEP	Net Reductions, BEP[a]	Total Facility Emissions (BEP+SEP)	Emission Offset Thresholds[b]	Net Increase	Emission Offsets Required
NOx	97	85.6	0.0	182.6	25	85.6	85.6[c]
SOx	24	8.8	-12.0	20.8	25	-3.2	0.0
VOC	24	24.3	0.0	48.3	25	24.3	23.3[d]
PM_{10}	97	40.1	-40.1	97.0	15	0	0.0

Notes:

a. Proposed reductions in permitted emissions from BEP.

b. MDAQMD Rule 1303 (b)(1). CO offsets not required because MDAQMD is in attainment of the CO standards.

c. Existing BEP NOx emissions were previously fully offset, so offsets are required only for the net increase from SEP.

d. Per District Rule 1305(a)(2)(b)(ii)b.II, offsets must be provided for emissions that exceed the 25 tpy threshold amount (48.3 – 25 = 23.3 tpy of offsets required).

5. Proposed Changes to Permit Conditions for BEP

This section presents the proposed changes to conditions of the BEP Permits to Operate for the gas turbines (B007953 and B007954, dated June 2, 2015) and Federal Operating Permit (#130202262, dated May 15, 2015). Proposed changes are shown in ~~strikeout~~ and **<u>bold</u>** **<u>underline</u>** font. Only the modified conditions are shown.

DESCRIPTION:

COMBUSTION TURBINE GENERATOR POWER BLOCK (CT1) consisting of: Natural gas fueled Siemens F Class Model V84.3A(2) Serial No. 800436 combustion turbine generator power block producing approximately 260 MW(e) with a connected heat recovery steam generator and a steam condensing turbine (shared with B007954), maximum turbine heat input of 1776 MMBtu/hr.

AND

COMBUSTION TURBINE GENERATOR POWER BLOCK (CT2) consisting of: Natural gas fueled Siemens F Class Model V84.3A(2) Serial No. 800436 combustion turbine generator power block producing approximately 260 MW(e) with a connected heat recovery steam generator and a steam condensing turbine (shared with B007953), maximum turbine heat input of 1776 MMBtu/hr.

CONDITIONS:

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf **<u>on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf</u>** on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the recommendations of its manufacturer or supplier and/or sound engineering principles.

4. Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NOx, and VOC during periods of startup, shutdown and malfunction:
    - a. Hourly rate, computed every 15 minutes, verified by CEMS and annual compliance tests:
        - i. NOx as NO2 – the most stringent of 19.80 lb/hr or 2.5 ppmvd corrected to 15% oxygen and averaged over one hour
        - ii. NOx as NO2 – effective May 7, 2016, 2.0 ppmvd corrected to 15% oxygen and averaged over a rolling 12 month period.
        - iii. CO – the most stringent of 17.5 lb/hr or 4.0 ppmvd corrected to 15% oxygen and averaged over three hours
        - iv. CO – 10 lb/hr averaged over a rolling 12-month period
    - b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
        - i. VOC as CH4 - 2.9 lb/hr (based on 1 ppmvd corrected to 15% oxygen)
        - ii. SOx as SO2 - 2.7 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
        - iii. PM 10 - ~~11.5~~ **<u>6.2</u>** lb/hr

6. Emissions from this equipment, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:
    - a. NOx - 5762 lb/day, verified by CEMS

b. CO - 8004 lb/day, verified by CEMS
c. VOC as CH4 - 239 lb/day, verified by compliance tests and hours of operation in steady-state, pre-mix mode.
d. SOx as SO2 - 130 lb/day, verified by fuel sulfur content and fuel use data
e. PM10 - ~~565~~ **298.5** lb/day, verified by compliance tests and hours of operation

7. Emissions from all Blythe Energy Project 1 permit units at this facility (as listed in Part I.A.1 of the Federal Operating Permit), including the cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:

a. NOx - 97 tons/year, verified by CEMS
b. CO - 97 tons/year, verified by CEMS
c. VOC as CH4 - 24 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode
d. SOx as SO2 - ~~24~~ **12** tons/year, verified by fuel sulfur content and fuel use data
e. PM10 - ~~97~~ **56.9** tons/year, verified by compliance tests and hours of operation

These limits shall apply to all emissions from all Blythe Energy Project permit units at this facility (as listed in Part I.A.1 of the Federal Operating Permit), and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

5.2 Changes to Conditions: BEP Federal Operating Permit

PART III: EQUIPMENT SPECIFIC APPLICABLE REQUIREMENTS; EMISSIONS LIMITATIONS; MONITORING, RECORDKEEPING, REPORTING AND TESTING REQUIREMENTS; COMPLIANCE CONDITIONS; COMPLIANCE PLANS
EQUIPMENT DESCRIPTIONS:

A. Permit #B007953 COMBUSTION TURBINE GENERATOR POWER BLOCK (CT1) consisting of: Natural gas fueled Siemens F Class Model V84.3A(2) Serial No. 800436 combustion turbine generator power block producing approximately 260 MW(e) with a connected heat recovery steam generator and a steam condensing turbine (shared with B007954), maximum turbine heat input of 1776 MMBtu/hr. Manufacturer, model and serial numbers will be specified when available.

B. Permit #B007954 COMBUSTION TURBINE GENERATOR POWER BLOCK (CT2) consisting of: Natural gas fueled Siemens F Class Model V84.3A(2) Serial No. 800437 combustion turbine generator power block producing approximately 260 MW(e) with a connected heat recovery steam generator and a steam condensing turbine (shared with B007953), maximum turbine heat input of 1776 MMBtu/hr. Manufacturer, model and serial numbers will be specified when available.

PERMIT CONDITIONS:

2. This equipment shall be exclusively fueled with pipeline quality natural gas with a sulfur content not exceeding 0.5 grains per 100 dscf **on a twenty-four hour basis and not exceeding 0.25 grains per 100 dscf** on a rolling twelve month average basis, and shall be operated and maintained in strict accord with the

recommendations of its manufacturer or supplier and/or sound engineering principles.

4. Emissions from this equipment (including its associated duct burner) shall not exceed the following emission limits at any firing rate, except for CO, NOx, and VOC during periods of startup, shutdown and malfunction:
a. Hourly rate, computed every 15 minutes, verified by CEMS and annual compliance tests:
i. NOx as NO2 – the most stringent of 19.80 lb/hr or 2.5 ppmvd corrected to 15% oxygen and averaged over one hour
ii. NOx as NO2 – effective May 7, 2016, 2.0 ppmvd corrected to 15% oxygen and averaged over a rolling 12 month period.
iii. CO – the most stringent of 17.5 lb/hr or 4.0 ppmvd corrected to 15% oxygen and averaged over three hours
iv. CO – 10 lb/hr averaged over a rolling 12-month period
b. Hourly rates, verified by annual compliance tests or other compliance methods in the case of SOx:
i. VOC as CH4 - 2.9 lb/hr (based on 1 ppmvd corrected to 15% oxygen)
ii. SOx as SO2 - 2.7 lb/hr (based on 0.5 grains/100 dscf fuel sulfur)
iii. PM 10 - ~~11.5~~ **6.2** lb/hr

6. Emissions from this equipment, including the duct burner, shall not exceed the following emission limits, based on a calendar day summary:
a. NOx - 5762 lb/day, verified by CEMS
b. CO - 8004 lb/day, verified by CEMS
c. VOC as CH4 - 239 lb/day, verified by compliance tests and hours of operation in steady-state, pre-mix mode.
d. SOx as SO2 - 130 lb/day, verified by fuel sulfur content and fuel use data
e. PM10 - ~~565~~ **298.5** lb/day, verified by compliance tests and hours of operation

7. Emissions from all Blythe Energy Project 1 permit units at this facility(as listed in Part I.A.1 of this Permit), including the cooling towers, shall not exceed the following emission limits, based on a rolling 12 month summary:
a. NOx - 97 tons/year, verified by CEMS
b. CO - 97 tons/year, verified by CEMS
c. VOC as CH4 - 24 tons/year, verified by compliance tests and hours of operation in steady-state, pre-mix mode
d. SOx as SO2 - ~~24~~ **12** tons/year, verified by fuel sulfur content and fuel use data
e. PM10 - ~~97~~ **56.9** tons/year, verified by compliance tests and hours of operation

These limits shall apply to all emissions from all Blythe Energy Project permit units at this facility (as listed in Part I.A.1, of the Federal Operating Permit), and shall include emissions during all modes of operation, including startup, shutdown and malfunction.

Appendix A

Sonoran Energy Project
Petition to Amend

Project Description, Air Quality and Public Health Sections

Sonoran Energy Project
(02-AFC-01C)

Petition to Amend
Change in Generation Technology

Submitted to the

California Energy Commission

Submitted by

AltaGas Sonoran Energy Inc.

August 2015

With Assistance from

CH2M HILL Engineers, Inc.
2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833

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Acronyms and Abbreviations

ALUCP	(Riverside County) Airport Land Use Compatibility Plan
APHUS	AltaGas Power Holdings (U.S.) Inc.
ARB	California Air Resources Board
BACT	best available control technology
BEP	(existing) Blythe Energy Project
BEP II	Blythe Energy Project Phase II
CAA	Clean Air Act
CAAQS	California ambient air quality standards
CAISO	California Independent System Operator
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CO	carbon monoxide
CTG	combustion turbine generator
DPM	diesel particulate matter
FSA	Final Staff Assessment
GE	General Electric
GSU	generator step-up unit
HRSG	heat recovery steam generator
I-10	Interstate 10
kV	kilovolt
LORS	laws, ordinances, regulations, and standards
$\mu g/m^3$	microgram(s) per cubic meter
MDAB	Mojave Desert Air Basin
MDAQMD	Mojave Desert Air Quality Management District
MW	megawatt
NOx	nitrogen oxide
NO_2	nitrogen dioxide
$PM_{2.5}$	particulate matter with aerodynamic diameter less than or equal to 2.5 microns
PM_{10}	particulate matter with aerodynamic diameter less than or equal to 10 microns
Ppm	part(s) per million
PTA	Petition to Amend

RO	reverse osmosis
ROW	right-of-way
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SCR	selective catalytic reduction
SEP	Sonoran Energy Project
SO_2	sulfur dioxide
STG	steam turbine generator
TAC	toxic air contaminant
T-BACT	toxics best available control technology
TDS	total dissolved solids
VOC	volatile organic compound

SECTION 1

Introduction

This introductory section contains background information, a description of the proposed modification and its necessity, a summary of potential environmental impacts, and a discussion of the consistency of the proposed modification with the current license.

1.1 Background

On December 14, 2005, the California Energy Commission (CEC) granted a license to Caithness Blythe II, LLC, to construct and operate the Blythe Energy Project Phase II (BEP II), Docket Number 02-AFC-01C. As licensed, BEP II is a 569-megawatt (MW), combined-cycle power plant consisting of two combustion turbines with fired heat recovery steam generators (HRSGs), a single steam turbine generator (STG), an 8-cell wet cooling tower, and ancillary equipment. The project site is located in eastern Riversides County, approximately 5 miles west of Blythe, California.

On October 23, 2009, Caithness Blythe II, LLC, submitted a Petition to Amend (PTA or Petition) the Commission Decision. The petition requested the following project modifications:

- Define a new point of electrical interconnection via a 2,100-foot-long, 500-kilovolt (kV) transmission line into the proposed Keim substation.
- Replace the Siemens Westinghouse V84.3a turbines, which are no longer available, with fast-start Siemens SGT6-5000F turbines.
- Modify the combustion turbine and steam turbine (ST) enclosure.
- Incorporate an auxiliary boiler to allow fast start technology.
- Increase the cooling tower size by 1,020 square feet to improve the efficiency and performance of the plant at higher temperatures.
- Optimize the General Arrangement.

Optimization of the General Arrangement encompasses these following changes:

- Relocation of the demineralized water storage tank
- Creation of two additional parking lots
- Relocation of the structure for the power control center
- Relocation of the workshop/ storage area
- Slight relocation of the general layout of the facility to the east
- Relocation of the control room building
- Relocation of the raw water storage tank

The Commission approved the amendment request on April 27, 2012 (TN 64945) with new or revised Conditions of Certification for Air Quality, Hazardous Materials Handling, Transmission System Engineering, Soil & Water Resources, and Worker Safety and Fire Protection.

On October 12, 2011, Caithness Blythe II, LLC, submitted a PTA to extend the BEP II license. The Commission approved this amendment request on December 16, 2011, extending the license to December 14, 2016 (TN 63164).[1] To date, construction of the project has not commenced.

[1] The Commission also approved a 5-month extension from December 14, 2011, to May 12, 2012, on December 14, 2011 (TN 63153).

On May 9, 2014, the current owner of BEP II, AltaGas Sonoran Energy Inc., submitted a Notice of Name Change/Petition to Change Ownership to the Commission. The Commission approved the ownership change on June 18, 2014. Upon acquisition of the project, AltaGas Sonoran Energy Inc. evaluated the project as licensed and determined that in light of current turbine technology, changes to the project design were needed to better support integration of renewables to the grid by providing fast-starting, faster-ramping, lower-minimum-load, higher-efficiency combined-cycle generation.

1.2 Description of Proposed Project Modification

AltaGas Sonoran Energy Inc. proposes two changes to the BEP II license. The first proposed change is to change the name of the project from Blythe Energy Project Phase II to the Sonoran Energy Project (SEP). The purpose of the proposed name change is to reduce potential confusion associated with the number of generating projects in the area using the name "Blythe."

The second proposed change involves the following amendments to the license:

- Define a new point of electrical interconnection via an approximately 1,320-foot, 161-kV transmission line to the Western Area Power Administration's Blythe substation located southeast of the project site via an existing transmission line located in the Southern California Edison (SCE) Buck Boulevard substation.
- Replace the two Siemens SGT6-5000F combustion turbines with a single, more efficient General Electric (GE) Frame 7HA.02 combustion turbine.
- Replace the Siemens STG with a more efficient single-shaft GE D652 STG.
- Increase the size of the auxiliary boiler to support GE's rapid response fast start capability.
- Decrease the size of cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements.
- Decrease the size of the emergency diesel fire pump engine.

A comprehensive project description is provided in Section 2.

1.3 Necessity of Proposed Modification

Sections 1769 (a)(1)(A), (B), and (C) of the CEC Siting Regulations require a discussion of the necessity for the proposed modification to the SEP and whether the modification is based on information known by the petitioner during the certification proceeding. The combustion turbine/steam turbine technologies being proposed were unavailable during the licensing of the project. Further, AltaGas Sonoran Energy Inc. acquired the SEP site license in May 2014 and has been working since that time on developing a project that will support the integration of renewables by providing efficient, fast-starting, fast-ramping, lower-minimum-operating-load, highly-efficient combined-cycle gas-fired generation that will utilize dry combustors and water treatment of cooling tower influent and share certain infrastructure with the existing, operational Blythe Energy Project (referred to herein as the existing BEP).

Section 2.2 (Transmission Interconnection Studies) provides additional information regarding the necessity of the proposed modification.

1.4 Summary of Environmental Impacts

Section 1769 (a)(1)(E) of the CEC Siting Regulations requires that an analysis be conducted to address impacts the proposed modification may have on the environment and proposed measures to mitigate any significant adverse impacts. Section 1769 (a)(1)(F) requires a discussion on whether the proposed modification affects the facility's ability to comply with applicable laws, ordinances, regulations, and standards (LORS). The proposed project modification will not result in an increase in environmental impacts beyond those previously analyzed during the licensing of the project. Furthermore, the proposed project modification is consistent with LORS. Section 3 of this Petition provides an environmental analysis of the proposed project modification and its consistency with LORS.

1.5 Consistency of Modification with License

Section 1769 (a)(1)(D) of the CEC Siting Regulations requires a discussion of the consistency of the proposed project modification with the assumptions, rationale, findings, or other basis of the Final Decision and whether the modification is based on new information that changes or undermines the basis of the final decision. Also required is an explanation of why the modification should be permitted. The proposed modification does not undermine the assumptions, rationale, findings, or other basis of the Final Decision (or other approved amendments) for the project. Additionally, the proposed modification is in keeping with the original intent of the project as a fully dispatchable, high-efficiency, quick-start facility able to meet the current and projected market demands of Southern California.[2] In addition, the proposed project modification should be licensed as it reflects the latest available combined-cycle technologies which will increase the overall electrical generation efficiency of the grid. This plant is expected to have a heat rate at minimum load which is similar to, or better than, most plants' heat rates at base load. Further, the proposed project modification is consistent with recent California Independent System Operator (CAISO) publications on the need for fast response Flexible Ramping Capability to support the growth of usually inflexible renewable energy resources.

[2] Transaction Number 64099, Blythe Energy Project Phase II (02-AFC-1C) Staff Analysis of Proposed Modifications, page 2.

SECTION 2

Project Description

Consistent with the CEC Siting Regulations Section 1769(a)(1)(A), this section describes the proposed project modification and the necessity for the modification.

2.1 Proposed Modification

2.1.1 Project Site

The project site is a 76-acre parcel located within the City of Blythe, in eastern Riverside County, California. The site is bound to the north by Riverside Avenue, to the east by the existing BEP, and to the south by Hobsonway. Figure 2-1 presents a site vicinity map. The site is fenced, sparsely vegetated, and relatively flat. The site slopes from an elevation of 350 feet in the northern portion of the parcel to 340 feet in the southern portion.

2.1.2 Project Overview

SEP is a natural gas-fired, water-cooled, combined-cycle, 553-MW net electrical generating facility, laid out using one-on-one single shaft arrangement utilizing a GE 7HA.02 gas turbine and a D652 steam turbine. The power block will consist of one natural gas-fired combustion turbine generator (CTG), one supplemental-fired HRSG, one steam turbine, an induced-draft cooling tower, and related ancillary equipment. Other equipment and facilities to be constructed are an auxiliary boiler, water treatment facilities, emergency services, and administration and maintenance buildings. The project site is the same as previously licensed for BEP II.

SEP will share some facilities with the existing BEP, including an existing 16-inch natural gas line located on the south side of the BEP property boundary. The gas line will be extended north to a new SEP conditioning and regulating station.

The interconnection is an approximately 1,320-foot, 161-kV transmission line from SEP to the existing Western Area Power Administration's Blythe substation. The Blythe substation is located on a separate parcel southeast of the SEP site. See subsection 2.1.3.2, Transmission System Engineering, for an expanded discussion of the SEP interconnections.

2.1.3 Facility Description, Design, Construction, and Operation

SEP has been designed using commercially proven technology equipped with monitoring, protection, and safety systems to provide safe and reliable operation over a 30-year operating life. It will consist of a single one-on-one, combined-cycle gas turbine power block consisting of one natural gas-fired CTG, one supplemental-fired HRSG, and one STG.

The power blocks will encompass the following principal combined design elements:

- One GE 7HA.02 CTG with a nominal rating of 333 MW.[3] The CTG will be equipped with an evaporative cooler on the inlet air system and dry low oxides of nitrogen oxide (NO_x) combustors.
- One GE D652 three casing, four bearing single, shaft configuration, double flow, side exhaust condensing steam turbine.
- One HRSG, which will be horizontal, triple-pressure, and natural circulation. The HRSG has a natural gas-fired duct burner for supplemental firing in the HRSG inlet ductwork and an emission reduction

[3] Gross output based on an ambient air temperature of 74 °F without duct firing and evaporative cooling.

system consisting of a selective catalytic reduction (SCR) unit to control NO_x stack emissions, and an oxidation catalyst to control carbon monoxide (CO) emissions in the outlet ductwork.

- One induced-draft, 10-cell cooling tower to provide cooling to the surface steam condenser and closed cooling water heat exchanger.
- A 161-kV transmission line to the Western Area Power Administration's Blythe substation.
- Direct connection with the existing BEP's 16-inch-diameter natural gas system.
- Connection to a new onsite 3-inch-diameter potable water system.
- Connection to a new well water supply system and interconnection to BEP's raw water system.

The auxiliary steam boiler will provide steam during gas turbine start-up and shutdown to allow startups and shutdowns to be accomplished more quickly. The boiler will provide up to 60,000 pounds per hour of steam to warming the steam turbine, maintaining vacuum on the steam condenser, and heating/reheating condensate.

Primary access to the SEP site will be provided via the north entrance off Riverside Avenue. The existing BEP entrance will be connected to the SEP entrance via a new access road. A secondary SEP access road will be off Hobsonway. Figures 2-2a and 2-2b show the facility general arrangements, including both electrical configurations. Figures 2-3a and 2-3b show typical elevation views of the project.

2.1.3.1 Water Supply, Treatment, and Wastewater Discharge

Operation of SEP will remain within the parameters of existing Condition of Certification WATER RES-4 and will not exceed a maximum of 2,800 acre-feet per year of water, based on the facility operating 7,000 hours per year. Figures 2-4a and 2-4b present a water balance for the project for a range of ambient conditions with and without duct firing.

Degraded (brackish) well water will be used directly as cooling tower makeup water and will feed the onsite service and potable water treatment system. This system will consist of a filtration system to remove iron and a potable water reverse osmosis (RO) system. Well water will pass through the filtration system and will be stored in a 470,000-gallon service/fire water storage tank for uses at the facility. The fire/service water storage tank will provide a minimum of 48 hours of operational storage and 2 hours of fire protection storage in the event of a disruption in the supply. The water passing through the potable water RO system will be stored in a potable water tank. Reject from the service and potable water treatment system will be directed to a wastewater treatment system. Water conservation measures employed on the project site contain brine concentrators to perform onsite recycling of wastewater, xeriscape landscaping (where required), and low/zero flow sanitary fixtures.

The wastewater treatment system uses a lime softening system, a cation exchange system, and an RO system to treat/recycle water. The discharge from this system will be stored in a treated wastewater tank. The waste generated by the lime softening system will be directed to a filter press system and the solids will be disposed of as nonhazardous waste similar to the licensed project. The effluent from the RO system will be directed to a brine concentrator. Water produced from brine concentrating will be sent to the treated wastewater tank. The concentrated brine will be disposed of in the onsite evaporation ponds.

The treated wastewater will be used in the combustion turbines inlet air evaporative coolers, and as steam-cycle makeup water. The steam-cycle makeup water will be treated using a RO train and electro-deionization prior to being stored in a 200,000-gallon demineralized water storage tank. Wastewater generated from the steam-cycle makeup water treatment system and from the evaporative coolers will be directed to a wastewater recycle sump, which discharges to the wastewater treatment system. Table 2-1 presents the SEP estimated daily and annual operational water use. Table 2-2 presents the well water expected quality.

Table 2-1. Estimated Daily and Annual Water Use for SEP Operation

Water Use	Average Daily Use Rate (gpm)	Maximum Daily Use Rate[a] (gpm)	Maximum Annual Use (acre-feet per year)
Well water	1,584	2,345	2,800

[a] Assumes an ambient temperature of 122 °F with duct firing and evaporative coolers operating.

Table 2-2. Expected Water Quality from Wells

Parameter	Units	Amount Detected
Calcium	ppm as Ca	41.5
Magnesium	ppm as Mg	8.5
Sodium	ppm as Na	298
Potassium	ppm as K	4.2
Sulfate	ppm as SO4	271
Chloride	ppm as Cl	280
Fluoride	ppm as F	1.80
Silica	ppm as SiO2	24.2
Iron	ppm as Fe	0.22
Phosphate	ppm as P	<0.05
Nitrate	ppm as Na	3.3
M Alkalinity	ppm as Na	151
P Alkalinity	ppm as CaCO3	0
Ammonia	ppm as CaCO3	<0.1
Silt Density Index		NA
Turbidity	NTU	1.24
Conductivity	µmhos/cm	1720
PH	pH units	7.4
Total Dissolved Solids	ppm TDS	1000
Total Suspended Solids	pmm TSS	<5
Biological Oxygen Demand	ppm BOD	5
Total Organic Carbon	ppm as C	12.9
Aluminum	ppm as Al	0.1
Arsenic	ppm as	0.003
Barium	ppm as Ba	<0.1
Boron	ppm as Bo	0.6
Cadmium	ppm as Cd	<0.001
Hexavalent Chromium	ppm as Cr	<0.01

Table 2-2. Expected Water Quality from Wells

Parameter	Units	Amount Detected
Total Chromium	ppm as Cr	0
Copper	ppm as Cu	0.07
Lead	ppm as Pb	<0.005
Mercury	ppm as Hg	<0.005
Nickel	ppm as Ni	<0.01
Selenium	ppm as Se	0.009
Strontium	ppm as Sr	0.93
Tin	ppm as Sn	<0.01
Zinc	ppm as Zn	0.07

The primary source of fire protection water for the project will be from a new raw water storage tank and emergency diesel fire pump engine. The water supplying the tank will be from wells located on the western side of the project site.

Any water that is not adequately treated for reuse will be discharged to one of two new evaporation ponds for ultimate disposal through evaporation. The evaporation ponds will be designed with high-density polyethylene (HDPE) liners and sufficient surface area to evaporate rainwater that falls directly in the pond as well as water discharged from the brine concentrator. At the average ambient temperature of 74 °F with evaporative cooling and no duct burner firing, discharge to the evaporation ponds will be approximately 14.4 gallons per minute (gpm) or approximately 23.1 million gallons per year.

For the site peak summer ambient temperature conditions, discharge to the evaporation ponds will be approximately 21.1 gpm (Table 2-3).

Table 2-3. Estimated Daily and Annual Wastewater Discharge for SEP Operation

Wastewater Use	Average Daily Discharge Rate (gpm)	Maximum Daily Discharge Rate (gpm)	Average Annual Use[a] (million gallons per year)
Wastewater to evaporation pond	14.4	21.1	23.1

[a] Assumes 5,500 hours of operation at the average daily maximum temperature and 1,500 hours of duct firing for a total of 7,000 hours of operation.

Actual annual discharge volumes are expected to be less than represented here and will depend on the actual operating profile and annual service factor of SEP in any given year. Table 2-4 presents the estimated wastewater quality discharged from the cooling tower to the brine concentrator and from the brine concentrator to the evaporation ponds.

Table 2-4. Expected Process Wastewater Quality

Parameter	Units	Cooling Tower Discharge to Brine Concentrator Concentration[a]	Discharge to Evaporation Pond Concentration[b]
Calcium	ppm as Ca	207.5	4,574
Magnesium	ppm as Mg	42.5	937

Table 2-4. Expected Process Wastewater Quality

Parameter	Units	Cooling Tower Discharge to Brine Concentrator Concentration[a]	Discharge to Evaporation Pond Concentration[b]
Sodium	ppm as Na	1490	32,842
Potassium	ppm as K	21	463
Sulfate	ppm as SO4	1355	29,866
Chloride	ppm as Cl	1400	30,858
Fluoride	ppm as F	9	198
Silica	ppm as SiO2	121	2,667
Iron	ppm as Fe	1.1	24
Phosphate	ppm as P	NA	NA
Nitrate	ppm as Na	16.5	364
M Alkalinity	ppm as Na	755	16,641
P Alkalinity	ppm as CaCO3	0	0
Ammonia	ppm as CaCO3	NA	NA
Silt Density Index		NA	NA
Turbidity	NTU	NA	NA
Conductivity	µmhos/cm	8600	189,558
PH	pH units	NA	NA
Total Dissolved Solids	ppm TDS	5000	111,310
Total Suspended Solids	pmm TSS	NA	NA
Biological Oxygen Demand	ppm BOD	25	551
Total Organic Carbon	ppm as C	64.5	1,422
Aluminum	ppm as Al	0.5	11
Arsenic	ppm as	0.015	0
Barium	ppm as Ba	NA	NA
Boron	ppm as Bo	3	66
Cadmium	ppm as Cd	NA	NA
Hexavalent Chromium	ppm as Cr	NA	NA
Total Chromium	ppm as Cr	0	0
Copper	ppm as Cu	0.35	8
Lead	ppm as Pb	NA	NA
Mercury	ppm as Hg	NA	NA
Nickel	ppm as Ni	NA	NA
Selenium	ppm as Se	0.045	1
Strontium	ppm as Sr	4.65	102

Table 2-4. Expected Process Wastewater Quality

Parameter	Units	Cooling Tower Discharge to Brine Concentrator Concentration[a]	Discharge to Evaporation Pond Concentration[b]
Tin	ppm as Sn	NA	NA
Zinc	ppm as Zn	0.35	8

[a] Cooling tower blowdown assumed 5 cycles of concentration.
[b] Estimated brine concentrator effluent, water to evaporation pond.
Note: NA = not applicable

Sanitary wastewater discharge from SEP will be sent to a new onsite septic system with a leach field.

Miscellaneous plant drainage will consist of area washdown, sample drainage, condensation, and drainage from facility equipment areas. Water from these areas will be collected in a system of floor drains, sumps, and pipes and routed to the wastewater collection system. This water will be routed through an oil/water separator as required to prevent oil from entering the water system. This clean water discharge will be directed to the cooling tower basin for reuse.

2.1.3.2 Transmission System Engineering

SEP will connect to the regional electrical grid via a new 161-kV Gen-Tie line. The new 161-kV Gen-Tie line will go from the high side of the SEP generator step-up unit (GSU) transformer to the existing Buck Boulevard (or Buck) 161-kV substation, on the existing BEP site. The new 161-kV Gen-Tie will deliver energy to the Western Area Power Administration’s 161-kV Blythe substation, via an existing 161-kV Buck–Blythe transmission line. Figure 2-5, Electrical 161kV General Arrangement Buck Termination Diagram, shows the configuration split for the Buck 230-kV and Buck 161-kV portions of the substation.

SEP delivery at either 230-kV or 161-kV provides flexibility for transmitting energy to multiple transmission systems (either the WAPA 161-kV or the Buck 230-kV). The support tower designs will look similar to the support tower designs in Figure 2-6 with an expected height of 85 to 110 feet.

2.1.3.2.1 Overhead Transmission Line Characteristics

The proposed Gen-Tie 161-kV line will be designed as a combination of single- and/or double-circuit self-supporting steel structures, which may be installed on concrete pier foundations.

The insulators for the 161-kV generation tie lines will be polymer or porcelain with overall lengths of approximately 10 to 15 feet for suspension insulators. The length of the insulator strings will be increased on structures other than tangent to ensure compliance with National Electrical Code (NEC), National Electrical Safety Code (NESC), and GO-95 clearances. The Gen-Tie line will be designed for the full capacity of SEP, which will be approximately 2150A at 161 kV.

2.1.4 Interconnection Substation Characteristics

The interconnection at the Buck 161-kV substation will utilize existing circuit breakers in series with the termination for the Blythe 161-kV termination. This configuration also utilizes the existing WAPA 161-kV transmission line into the Blythe 161-kV system.

The new SEP power block will connect the Gen-Tie to the existing transmission system through a single 230-kV class, 3000A circuit breaker (operated at 161 kV) in series with the SEP GSU transformer. The interconnection to the Buck and CRS substations and all equipment will be designed to ensure compliance with applicable National Electric Code (NEC), National Electrical Safety Code (NESC), and GO-95 rules following industry standard requirements. The main buses and the bays will also be designed following these requirements. Power for SEP will be back-fed through the GSU transformer and auxiliary transformer. Auxiliary controls and protective relay systems for the substations may be located in the

SEP control building for coordination of the Gen-Tie. No existing underground interconnect lines will be affected by the project.

2.2 Transmission Interconnection Studies

The existing adjacent BEP was originally interconnected to the transmission system via the Buck substation and a new overhead transmission line to the Blythe 161-kV substation, delivering approximately 520-MW to the WAPA transmission system. However, in June 2010, a new 230-kV transmission line from Buck to Julian Hinds was energized and the WAPA tie to Blythe was essentially abandoned, butall transmission structures and facilities remain in place.

Because SEP is largely replacing MWs from the previous delivery of BEP to WAPA at the same electrical node, the actual marginal addition of generation to the grid at this connection point is small (approximately 34 MW). This will make system impact issues minimal.

The SEP interconnection request was filed with WAPA on November 30, 2014. The interconnection fee has been paid and SEP has a position in the WAPA queue. Appendix 2A contains a copy of the executed System Impact Study.

2.3 Transmission Line Safety and Nuisances

It is anticipated that no modifications are necessary for the existing 161-kV transmission line connecting the Buck substation to the WAPA transmission system. This section discusses the safety and nuisance issues associated with the project's transmission line.

2.3.1 Electrical Clearances

Typical high-voltage overhead transmission lines are composed of bare conductors connected to supporting structures by means of porcelain, glass, or polymer insulators. The air surrounding the energized conductor acts as the insulating medium. Maintaining sufficient clearances, or air space, around the conductors to protect the public and utility workers is paramount to the safe operation of the transmission line. The required safety clearance required for the conductors is determined by considering various factors such as: the normal operating voltages, conductor temperatures, short-term abnormal voltages, windblown swinging conductors, contamination of the insulators, clearances for workers, and clearances for public safety. Minimum clearances are specified in the NESC (IEEE C2) and California Public Utilities Commission (CPUC) General Order (GO) 95. Electric utilities, state regulators, and local ordinances may specify additional (more restrictive) clearances.

The SEP gen-tie line(s) connecting to the existing transmission system will be designed to meet appropriate national, state, and local clearance requirements.

2.3.2 Electrical Effects

The electrical effects of high-voltage transmission lines, both within the SEP site and outside of the SEP site, fall into two broad categories: corona effects and field effects. Corona is the ionization of the air that occurs at the surface of the energized conductor and suspension hardware because of high electric field strength at the surface of the metal during certain conditions. Corona may result in radio and television reception interference, audible noise, light, and production of ozone. Field effects are the voltages and currents that may be induced in nearby conducting objects. A transmission line's inherent electric and magnetic fields cause these effects. Based on the analyses below, SEP will not result in any significant impacts to electric and magnetic fields or audible noise or radio and television interference.

2.3.2.1 Electric and Magnetic Fields

The SEP 161-kV transmission line that connects the Blythe substation via the existing Buck substation (located on the BEP site) will not affect the public because it is located entirely within the site. No changes are proposed for the existing 161-kV transmission line between the Buck and WAPA Blythe substations. The potential impacts of operating this transmission line were addressed during the licensing of BEP, and SEP's impacts will be similar in nature. The estimated electric field of the existing 161-kV Buck to Blythe transmission line at the center of the transmission line right-of-way (ROW) substation is 0.9 kV/meter, and is 0.7 kV/meter at the edge of the ROW. The estimated magnetic field under the Buck to Blythe 161-kV transmission line and at the center of the ROW is 46 milligauss (mG) (0.046 G), and 35 mG (0.035 G) at the edge of the ROW.

2.3.2.2 Audible Noise and Radio and Television Interference

The new 161-kV interconnection line from SEP to the existing Buck substation will be designed and constructed not to affect the public from audible noise and radio and television interference as they are located within the SEP and BEP sites.

No changes are proposed for the 161-kV transmission line connecting the Buck substation to the WAPA transmission system. The impacts associated with the operation of this transmission line were addressed in the BEP II proceeding and SEP's impacts will be similar in nature.

2.3.2.3 EMF, Audible Noise, and Radio and Television Interference Assumptions

EMF, audible noise, and radio and television interference near power lines vary with regard to the line design, line loading, distance from the line, and other factors. The new overhead 161-kV line located between the SEP power blocks and the Buck substation are entirely located within the SEP and BEP sites.

Electric fields, corona, audible noise, and radio and television interference depend on line voltage and not the level of power flow. Because line voltage remains nearly constant for the new SEP 161-kV line to the Buck substation during normal operation, the audible noise associated with the transmission lines in the area will be of the same magnitude before and after construction of SEP.

The magnetic field is proportional to line loading (amperes), which varies as demand for electrical power varies and as generation from the generating facility is changed by the system operators to meet changes in demand.

SEP construction and operation, including the interconnection of SEP to the Buck substation and transmission system, are not expected to result in significant changes in EMF levels, corona, audible noise, or radio and television interference.

The impacts associated with the operation of this transmission line were addressed in the BEP II proceeding and SEP's impacts will be similar in nature.

2.3.2.4 Induced Current and Voltages

The proposed SEP transmission lines will be constructed in conformance with CPUC GO-95 and Title 8 California Code of Regulations (CCR) 2700 requirements, consistent with the licensed project. Therefore, hazardous shocks are unlikely to occur as a result of project construction, operation, or maintenance.

2.3.3 Fire Hazards

The transmission interconnection will be designed, constructed, and maintained in accordance with applicable standards including GO-95, which establishes clearances from other manmade and natural structures to mitigate fire hazards. The project owner is expected to maintain the transmission line corridor and the immediate area in accordance with existing regulations and accepted industry practices that will address identification and abatement of fire hazards.

2.3.4 Applicable Laws, Ordinances, Regulations, and Standards

The SEP transmission system will be designed to comply with applicable state and federal LORS and Conditions of Certification TSE-1 through TSE-8 and TLSN-1 through TLSN-5.

2.3.5 Project Schedule

Construction of SEP is scheduled to occur from the 2nd quarter of 2016 through the 2nd quarter of 2018. Final engineering is scheduled for the first half of 2016 (6 months) with site mobilization scheduled to start during the 2nd quarter of 2016. Construction is scheduled to be complete in the 2nd quarter of 2018 (approximately 26 months, including 4 months of commissioning). Table 2-5 present SEP's construction schedule.

Table 2-5. Schedule Major Milestones

Activity	Commence Activity	Completion of Activity
Site Mobilization/Start of Construction	2nd Quarter 2016	NA
Commissioning	4th Quarter 2017	2nd Quarter 2018
Commercial Operation	2nd Quarter 2018	2nd Quarter 2018

The construction plan is based on a single 10-hour shift/6 days per week. Overtime and additional shift work may be used to maintain or enhance the construction schedule. Construction will most typically take place between the hours of 6 a.m. and 6 p.m., Monday through Saturday; however, additional hours may be necessary to maintain schedule or to complete critical construction activities (such as large concrete pours). During the commissioning and startup phase, some activities may continue 24 hours per day, 7 days per week. Table 2-6 provides the projected construction craft personnel power by month. An estimated peak of 325 craft and professional personnel is anticipated in the 2nd quarter of 2017 for SEP.

Approximately 13.5 acres of onsite construction laydown will be required for equipment storage and construction workforce parking. Additional room onsite has been allocated for staging and construction trailers.

Construction access will generally be from Hobsonway via Christopher Columbus Transcontinental Highway Interstate 10 (I-10). Large or heavy equipment, such as the turbine, generator, GSU transformers, and HRSG modules will be delivered to the site by heavy haul truck/trailer following specific requirements of "heavy/oversize load" permits from appropriate agencies (City of Blythe and/or Riverside County). Large and heavy components of the HRSG will arrive by ship at the Port of Long Beach. From the Port of Long Beach, these large components will be hauled directly to the SEP site for immediate installation. In the event heavy equipment arrives but cannot be transported and transferred directly into its final position at SEP, it will be hauled to the laydown area. The steam turbine and combustion turbines are expected to arrive by rail. The local rail siding for the project is located 5.75 miles south of the intersection between SR-78 and I-10 (6.25 miles south of project site).

Construction water will be groundwater from either the new onsite wells (when completed) or the existing BEP water supply system. During construction, the average daily water use is expected to be approximately 20,000 gallons. During the commissioning period, when activities such as hydrostatic testing, cleaning and flushing, and steam blows of the HRSG and steam cycles will be conducted, average water usage is estimated at 30,000 gallons per day with a maximum daily use of 643,080 gallons. Hydrostatic test water and cleaning water will be tested and disposed in accordance with applicable LORS.

Water for sanitary purposes will either be bottled water or provided by BEP's potable water system. Portable toilets will be provided throughout the site.

- Lighting will be required to facilitate SEP night construction and commissioning activities. Construction lighting will, to the extent feasible and consistent with worker safety codes, be directed toward the center of the construction site and shielded to prevent light from straying offsite. Task-specific construction/commissioning lighting will be used to the extent practical while complying with worker safety regulations.

- During some construction periods and during the commissioning/startup phase of the project, some activities will continue 24 hours per day, 7 days per week. During periods when nighttime construction/commissioning activities take place, illumination that meets state and federal worker safety regulations will be required. To the extent possible, the nighttime construction/commissioning lighting will be erected pointing toward the center of the site where activities are occurring and will be shielded. Task-specific lighting will be used to the extent practical while complying with worker safety regulations. Despite these measures, there may be limited times during the construction/commissioning period when the project site may appear as a brightly lit area as seen in close views and from distant areas.

2.4 Facility Operation

SEP will be capable of being dispatched throughout the year and will have annual availability of 95 percent. It will be possible for plant availability to exceed 99 percent for a given 12-month period.

SEP will be operated from the BEP control room. As such, the incremental increase in operational staffing for SEP is expected to be 9 employees, including 5 plant operators, 1 administrative person, 2 mechanics, and 1 plant engineer, in three rotating shifts. The facility will be capable of operating 24 hours per day, 7 days per week.

SEP is expected to operate at full load, although the plant will have the ability to serve both peak and intermediate loads with the added capabilities of rapid startup, low turndown capability (ability to turn down to a low load of 30 percent of the combustion turbine’s output, depending on ambient conditions), and steep ramp rates, (50 MW per minute when operating above minimum gas turbine capacity). The project configuration will be more efficient than many, if not all of the existing gas-fired steam generation facilities in southern California. SEP will provide much needed flexible operating characteristics for integrating renewable energy into the electrical grid and providing fast response load following service. SEP is expected to have an annual capacity factor of between 35 and 80 percent. The actual capacity factor for SEP in any month or year will depend on weather-related customer demand, load growth, renewable energy supplies, generating unit retirements and replacements, the level of generating unit and transmission outages, and other factors. The exact operational profile of SEP will ultimately depend on electrical grid needs at the time and dispatch decisions made by the offtaker or load serving entity contracted with AltaGas Sonoran Energy Inc. to buy and distribute the power generated and the CAISO.

2.4.1 Facility Safety Design

SEP will be designed to maximize safe operation. Earthquake, flood, and fire are potential hazards that could affect the facility. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant**.** SEP’s design will contain safety measures that will be consistent with (or exceed) the design for the licensed BEP II. SEP will conform to the latest California Code of Regulations Title 24 and the California Building Code to minimize potential impacts associated with earthquakes, floods, and fires.

2.4.2 Natural Hazards

As noted in the BEP II Commission Decision, the project site is not located within a State of California Earthquake Fault Zone, near any known active fault. Furthermore, the project site is not located within the 100-year floodplain. The project design will conform to the California Code of Regulations Title 24 and the California Building Code to reduce potential seismic hazards. Appendix 2B contains the structural seismic design criteria for the buildings and equipment. Because the SEP site is the same site that was licensed by the CEC in the BEP II proceeding, no changes in impacts or mitigation requirements from natural hazards are expected.

Table 2-6. Projected Construction Craft Personnel Power by Month

	2016							2017												2018										Man Months	Days/ Mo.	Man Days	Hours
Craft	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**				
Construction	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29				
Worker/Insulator												15	30	40	40	40	40	40	20	15	10									290	23	6,670	66,700
Boilmakers								20	40	60	80	80	100	80	80	70	65	55	23											753	23	17,319	173,190
Carpenters	5	10	10	15	20	20	20	15	15	15	15	12																		172	23	3,956	39,560
Cement Finishers							1	2	3	4	4	3	2	1																20	23	460	4,600
Common Laborers	5	5	5	5	5	5	5	5	10	10	10	10	10	10	10	10	8	5	5	5	5	5								153	23	3,519	35,190
Electricians	5	5	10	10	20	20	30	30	40	40	40	40	40	40	40	30	30	30	20	10	5									535	23	12,305	123,050
Equipment Operators, Heavy	4	4	6	15	15	10	6	6	5																					71	23	1,633	16,330
Equipment Operators, Light			2	2	1	1	1	1	1	1	1	1																		12	23	276	2,760
Equipment Operators, Medium			8	10	10	22	20	20	15	15	8	8	5	5																146	23	3,358	33,580
Equipment Operators, Oilers		1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1											24	23	552	5,520
Mechanical Equipment																														0	23	0	0
Millwrights	2	2	4	4	8	8	10	10	8	8	4	4	1	1																74	23	1,702	17,020
Plumbers Helper						1																								1	23	23	230
Plumbers						1	1																							2	23	46	460
Painters,																				4	4	4								12	23	276	2,760
Rodmen (Reinforcing)	4	4	4	8	8	10	20	20	10	4	4																			96	23	2,208	22,080
Skilled Trade										1	1																			2	23	46	460
Structural Steel Workers					10	10	10	20	20	30	40	40	40	15	10	10	5	2												262	23	6,026	60,260
Structural Steel Welders						1	1	2	3	3	3	2	1																	16	23	368	3,680
Steamfitters/Pipefitters									20	40	60	70	70	70	70	70	55	55	50	20										650	23	14,950	149,500
Truck Drivers, Heavy			1	4	4	4	1	1	1																					16	23	368	3,680
Truck Drivers, Light										1																				1	23	23	230
Transmission Line	0	0	0	0	0	0	1	28	46	50	48	33	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	220	23	5060	50600	
Total Craft	25	31	51	74	102	114	129	182	239	284	320	320	314	263	251	231	204	188	119	54	24	9	0	0	0	0	0	0					
Total Supervision	**1**	**1**	**2**	**2**	**2**	**2**	**2**	**4**	**4**	**5**	**5**	**5**	**5**	**5**	**5**	**5**	**4**	**4**	**2**	**1**	**1**	**1**											

2.4.3 Emergency Systems and Safety Precautions

This section discusses the fire protection systems, emergency medical services, and safety precautions to be used by project personnel. Compliance with these requirements will minimize project effects on public and employee safety. SEP will have emergency and safety systems that comply with current fire and safety regulations. These safety systems will either meet or exceed those analyzed in the BEP II license.

2.4.3.1 Fire Protection Systems

The project will rely on onsite fire protection systems and local fire protection services. The fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. The project will have the following fire protection systems.

Carbon Dioxide and Dry Chemical Fire Protection Systems. These systems protect the CTG and certain accessory equipment compartments from fire. The system will have fire detection sensors in all protected compartments. Actuating one sensor will provide a high-temperature alarm on the CTG control panel. Actuating a second sensor will trip the CTG, turn off ventilation, close ventilation openings, and automatically release the gas and chemical agents. The gas and chemical agents will be discharged at a design concentration adequate to extinguish the fire.

Sprinkler and Deluge Systems. These systems protect steam turbine equipment, buildings, and large transformers and specific electrical equipment rooms. The steam turbine pedestal area will be protected by an automatic dry pipe sprinkler system. The steam turbine lubrication oil reservoir will be protected by dry pilot sprinklers, and the steam turbine bearing areas will be protected with preaction sprinkler systems. Buildings will generally be protected by automatic wet-type sprinkler systems. Large transformers (GSU and auxiliary transformers) will be protected by automatic water spray (deluge) systems. Electrical equipment and battery rooms will be protected with preaction sprinkler systems.

Fire Hydrants/Hose Stations. This system will supplement the plant's fixed fire suppression systems. Water will be supplied from the plant fire water system.

Fire Extinguisher. The plant administrative/control/warehouse/maintenance building, water treatment building, and other structures will be equipped with portable fire extinguishers as required by the local fire department.

Local Fire Protection Services. In the event of a major fire, the plant personnel will be able to call upon the City of Blythe Fire Department for assistance. The Hazardous Materials Business Plan for the plant will contain all information necessary to allow firefighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

2.4.3.2 Personnel Safety Program

SEP will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize project effects on employee safety.

2.5 Facility Reliability

This section discusses the expected facility availability, equipment redundancy, fuel availability, water availability, and project quality control measures.

2.5.1 Facility Availability

SEP is designed to operate between approximately 40 and 100 percent of base load to support dispatch service in response to customer demands for electricity. SEP is designed for an operating life of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures will be consistent with industry standard practices to maintain the useful life status of plant components. SEP's availability factor of 95 percent is consistent with the licensed BEP II availability factor of between 92 and 98 percent.

2.5.2 Redundancy of Critical Components

The following subsections identify equipment redundancy as it applies to SEP availability. Specifically, redundancy in the combined-cycle power block and in the balance-of-plant systems that serve it is described. The power block will be served by the following balance-of-plant systems: fuel supply system, DCS, boiler feedwater system, condensate system, demineralized water system, power cycle makeup and storage, steam condensing system, closed cooling water system, and compressed air system. Major equipment redundancy is summarized in Table 2-7.

2.5.2.1 Power Block

SEP consists of one CTG/HRSG power generation train that operates in a combined-cycle power block. The heat input from the exhaust gas from the CTG will be used in the steam generation system to produce steam. Thermal energy in the steam from the steam generation system will be converted to mechanical energy and then to electrical energy in the steam turbine subsystem. The expanded steam from the turbine will be condensed and recycled to the feedwater system. Power from the steam turbine subsystem will contribute approximately 38 percent of the total unfired power block output. If the steam turbine is nonoperational for any reason, the plant may still operate in bypass mode with the CTG at 100 percent load.

Table 2-7. Major Equipment Redundancy

Description	Number Per CCGT Block	Note
CTG and HRSG	1 – 100% trains	Steam turbine bypass system allows the CTG/HRSG train to operate at base load with the steam turbine out of service
Natural Gas Fired Duct Burners	1 – One per HRSG	Duct burners will be used for augmenting maximum power output.
Steam Turbine	1 – 100%	See note above pertaining to CTG and HRSG
HRSG Feedwater Pumps	2–100%	—
Condensate Pumps	2 – 100%	—
Surface Condenser	1 – 100%	Condenser must be in operation for plant to operate, however, it will contain two sections and spare tubes.
Cooling Tower	1 – 100%	—
Circulating Water Pumps	2 – 60%	Plant may be operated with one CW pump out of service at reduced capacity
Closed Cooling Water Pumps	2 – 100%	—
Closed Cooling Water Heat Exchanger	2 – 100%	—
Air Compressors	2 – 100%	Additional capacity will also be provided via instrument air receivers
Reverse Osmosis Units	2 – 100%	—
Lime Softener and Granular Filters	100% spare capacity	—

SEP has two fewer electrical generators than the licensed BEP II's two-on-one design. However, the level of redundancy in the ancillary systems is comparable between the SEP and licensed BEP II designs.

Furthermore, linking SEP and the existing BEP's water supply and wastewater systems ensure added redundancy and reliability to both plants.

2.5.2.2 CTG Subsystems

The SEP CTG subsystems will contain the combustion turbine, inlet air filtration, cooling/heating system, turbine and generator lubrication oil systems, starting system, fuel system, generator and excitation systems, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas. The thermal energy will be converted into mechanical energy through rotation of the combustion turbine, which drives the compressor and generator. Exhaust gas from the combustion turbine will be used to produce steam in the associated HRSG. The generator excitation system will be a solid-state static system. Combustion turbine control and instrumentation (interfaced with the DCS) will cover the turbine governing system, the protective system, and the sequence logic.

2.5.2.3 HRSG Subsystems

The SEP steam generation system will consist of the HRSG and blowdown systems. The HRSG system will provide for the transfer of heat from the exhaust gas of a combustion turbine for the production of steam. This heat transfer will produce steam at the pressures and temperatures required by the steam turbine. The HRSG system will consist of ductwork, duct burner, heat transfer sections, an SCR system, and an oxidation catalyst module, as well as safety and auto relief valves and processing of continuous and intermittent blowdown drains.

2.5.2.4 Steam Turbine Subsystems

The SEP steam turbine will convert the thermal energy to mechanical energy to drive the steam turbine shaft to make electrical energy in the generator. The gas turbine and steam will be arranged on a single shaft with a single generator. The steam turbine will be capable of de-coupling from the CTG through the use of a clutch. The basic subsystems will include the steam turbine and auxiliary systems, turbine and generator lubrication oil systems, generator/exciter system, and turbine control and instrumentation.

2.5.2.5 Plant Distributed Control System

The SEP DCS will be a redundant microprocessor-based system and will have a functionally distributed architecture comprising a group of similar redundant processing units; these units will be linked to a group of operator consoles and an engineer workstation by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes. Because they will be redundant, no single processor failure can cause or prevent a unit trip.

The DCS will interface with the control systems furnished by the CTG, ST, and HRSG suppliers to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The system will be designed with enough redundancy to preclude a single device failure from significantly affecting overall plant control and operation. Consideration will be given to the action performed by the control and safety devices in the event of control circuit failure. Controls and controlled devices will move to the safest operating condition upon failure.

Plant operation will be controlled from the operator panel in the control room. The operator panel will consist of multiple individual CRT/keyboard consoles, an engineering workstation, and a historian workstation. Each CRT/keyboard console will be an independent electronic package so that failure of a single package will not disable more than one CRT/keyboard. The engineering workstation will allow the control system operator interface to be revised by authorized personnel.

2.5.2.6 HRSG Feedwater System

The HRSG feedwater system will transfer feedwater from the low-pressure steam drum to the high-pressure sections of the HRSG. The system will consist of two, 100-percent-capacity pumps for supplying the HRSG. Each pump will be multistage, horizontal, and motor-driven and will include regulating control valves, minimum flow recirculation control, and other associated pipes and valves. The low-pressure system will receive feedwater directly from the low pressure drum using the pressure supplied by the condensate pumps.

2.5.2.7 Condensate System

The condensate system will provide a flow path from the condenser hot well to the HRSG low-pressure drum. The condensate system will include two, 100-percent-capacity, multistage, vertical, motor-driven condensate pumps.

2.5.2.8 Power Cycle Makeup Water Treatment System

The cycle makeup will include two, 100-percent-capacity trains of two-pass RO equipment followed by an electro-deionization system with two 100-percent-capacity trains.

2.5.2.9 Power Cycle Water Makeup and Storage

The power cycle water makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for system cycle makeup, CTG water wash, and chemical cleaning operation. The major components of the system are a single demineralized water storage tank and two 100-percent-capacity, horizontal, centrifugal, cycle makeup water pumps.

2.5.2.10 Compressed Air System

The compressed air system will be designed to supply service and instrument air for the facility. Dry, oil-free instrument air will be provided for pneumatic operators and devices throughout the plant. Compressed service air will be provided to appropriate areas of the plant as utility stations consisting of a ball valve and quick disconnect fittings.

The instrument air system will be given demand priority over the service air system. A backpressure control valve will cut off the air supply to the service air header so as to maintain the minimum required instrument air pressure.

Two, 100-percent-capacity, oil free, rotary screw package air compressors will supply compressed air to the service and instrument air systems. Two, 100-percent-capacity, heat-less desiccant air dryers will be provided to dry the service and instrument air.

2.5.3 Fuel Availability

Consistent with the existing BEP II license, fuel will be delivered via an existing SoCalGas 16-inch-diameter pipeline located on the south side of the project site. SoCalGas has confirmed that its system has sufficient capacity to supply SEP at this location.

2.5.4 Water Availability

Consistent with the existing BEP II license, SEP will use a maximum of 2,800 acre-feet per year of water provided by degraded (brackish) groundwater wells for power plant cooling and process water, fire protection, and sanitary uses.

2.5.5 Wastewater Treatment Availability

SEP will discharge an average of 14.4 gallons per minute of process wastewater to the onsite evaporation ponds, which is consistent with average BEP II's discharge of 13 gallons per minute. All sanitary waste will go to an onsite septic system with a leach field.

2.6 Thermal Efficiency

The maximum gross thermal efficiency that can be expected from the configuration specified for SEP is approximately 60 percent on a lower heating value basis. This level of efficiency is achieved when the facility is base-loaded. SEP reflects the latest available combined-cycle technologies which will increase the overall electrical generation efficiency of the grid. The project is expected to have a heat rate at minimum load which is similar to, or better than, most plants' heat rates at base load. Further, the proposed modification is consistent with recent CAISO publications on the need for fast response Flexible Ramping Capability to support the growth of usually inflexible renewable energy resources. It is expected that SEP will be primarily operated in load-following or cycling service. The number of startup and shutdown cycles is expected to be approximately 200 per year. Figures 2-7a and 2-7b present a heat and mass balance for a range of ambient temperatures with and without the duct burners operating. BEP II was licensed with a thermal efficiency of 55 to 58 percent.[4]

Plant fuel consumption will depend on the operating profile of the power plant. It is estimated that the range of fuel consumed by the power plant will be from a minimum of near zero BTUs per hour to a maximum of approximately 2,971 MMBtu/hr - LHV at 59˚F ambient temperature (or 78,434 MMBtu/day – HHV). By contrast, BEP II was licensed assuming 116,316 MMBtu/day – HHV of fuel consumption.[5]

The net annual electrical production of SEP cannot be accurately forecasted at this time because of uncertainties in the system load-dispatching model and the associated uncertainties in load forecasts. The maximum annual generation possible from the facility is estimated to be approximately 3,235 gigawatt hours per year (based on an annual average facility base load rating of 486.5 MW, 95 percent availability, and 7,000 hours per year).

2.7 Facility Closure

Facility closure can be temporary or permanent. Temporary closure is defined as a shutdown for a period exceeding the time required for normal maintenance, including closure for overhaul or replacement of the CTG. Disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts are cause for temporary closure. Permanent closure is defined as a cessation in operation with no intent to restart operation because of plant age, damage to the plant beyond repair, economic conditions, or other reasons. The following sections discuss temporary and permanent facility closure.

2.7.1 Temporary Closure

For a temporary facility closure, where there is no release of hazardous materials, security of the facilities will be maintained on a 24-hour basis, and the CEC and other responsible agencies will be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operation will be implemented. The contingency plan will be conducted to ensure conformance with all applicable LORS and the protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, may encompass the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS.

Where the temporary closure includes damage to the facility, and there is a release or threatened release of regulated substances or other hazardous materials into the environment, procedures will be followed as set forth in a Risk Management Plan and a Hazardous Materials Business Plan to be developed. Procedures will encompass methods to control releases, notification of applicable

[4] BEP II Commission Decision, CEC-800-2005-005-CMF, page 287.

[5] BEP II Petition to Amend, October 26, 2009, Table 5.2-2.

authorities and the public, emergency response, and training for plant personnel in responding to and controlling releases of hazardous materials. Once the immediate problem is solved, and the regulated substance/hazardous material release is contained and cleaned up, temporary closure will proceed as described above for a closure where there is no release of hazardous materials.

2.7.2 Permanent Closure

The planned life of SEP is 30 years. However, if SEP were still economically viable, it could be operated longer. It is also possible that the facility could become economically noncompetitive in less than 30 years, forcing early decommissioning. Whenever the facility is permanently closed, the closure procedure will follow a plan that will be developed as described below.

The removal of the facility from service, or decommissioning, may range from “mothballing” to the removal of all equipment and appurtenant facilities, depending on conditions at the time. Because the conditions that will affect the decommissioning decision are largely unknown at this time, these conditions will be presented to the CEC when more information is available and the timing for decommissioning is more imminent.

To ensure that public health and safety and the environment are protected during decommissioning, a decommissioning plan will be submitted to the CEC for approval prior to decommissioning. The plan will address the following:

- Proposed decommissioning activities for the facility and all appurtenant facilities constructed as part of the facility
- Conformance of the proposed decommissioning activities to all applicable LORS and local/regional plans
- Activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities
- Decommissioning alternatives other than complete restoration
- Associated costs of the proposed decommissioning and the source of funds to pay for the decommissioning

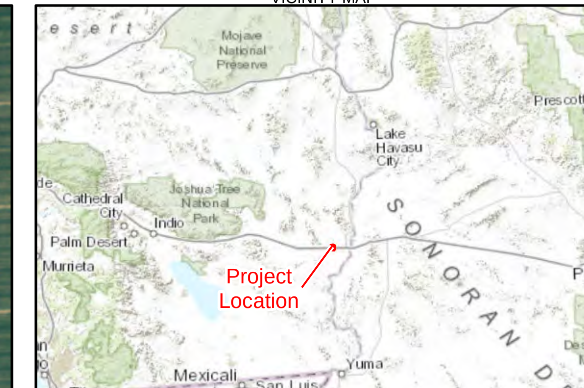
In general, the decommissioning plan for the facility will attempt to maximize the recycling of all facility components. If possible, unused chemicals will be sold back to the suppliers or other purchasers or users. All equipment containing chemicals will be drained and shut down to ensure public health and safety and to protect the environment. All nonhazardous wastes will be collected and disposed of in appropriate landfills or waste collection facilities. All hazardous wastes will be disposed of according to all applicable LORS. The site will be secured 24 hours per day during decommissioning activities.

2.8 References

Caithness Blythe II, LLC. 2009. *Petition to Amend the Blythe Energy Project Phase II (02-AFC-1C)*. October 26.

California Independent System Operator (CAISO). 2008. Generator Interconnection Process Reform, Revised Draft Proposal, June 27, 2008. California Independent System Operator. Available at: http://www.caiso.com/1f42/1f42c00d28c30.html.

VICINITY MAP



LEGEND

Project Details

Property Boundary

Image Source: NAIP 2012

N

0 400 800
Feet

FIGURE 2-1
Site Vicinity Map
Sonoran Energy Project
Riverside County, California

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LEGEND

1 - STEAM TURBINE
2 - STEAM TURBINE LO MODULE
3 - GAS TURBINE
4 - GAS TURBINE LO MODULE
5 - HEAT RECOVERY STEAM GENERATOR
6 - HRSG LP/ECONOMIZER RECIRC PUMP
7 - HRSG BLOW DOWN SUMP
8 - STEP UP TRANSFORMER
9 - AQUEOUS AMMONIA STORAGE
10 - AQUEOUS AMMONIA FORWARD PUMPS
11 - FUEL GAS CONDITIONING AND PRESSURE REGULATING STATION
12 - FUEL GAS DRAINS TANK
13 - SURFACE CONDENSER
14 - COOLING TOWER
15 - CIRCULATING WATER PUMPS
16 - CLOSED COOLING WATER (CCW) HEAT EXCHANGER
17 - CCW EXPANSION TANK
18 - CCW PUMPS
19 - AUX BOILER
20 - AUX BOILER BLOW DOWN SUMP
21 - WASH WATER SKID
22 - WASH WATER DRAINS TANK
23 - AUX TRANSFORMER
24 - GENERATOR LINE ACCESSORY COMPARTMENT
25 - GENERATOR NEUTRAL ACCESSORY COMPARTMENT
26 - INLET AIR FILTER/EVAPORATIVE COOLER
27 - NOT USED
28 - NOT USED
29 - GE DLN GAS MODULE
30 - PACKAGED ELECTRONIC/ELECTRICAL CONTROL COMPARTMENT
31 - FEEDWATER PUMPS
32 - DEMIN WATER TANK
33 - DEMIN WATER PUMPS
34 - RAW WATER TANK
35 - RAW WATER PUMPS
36 - WATER TREATMENT AREA
37 - CONDENSATE PUMPS
38 - HRSG BLOW DOWN TANK
39 - CONDENSATE DRAINS / FLASH TANK
40 - FIRE PUMP SKID
41 - AIR COMPRESSORS, DRYERS AND RECEIVER
42 - VACUUM PUMPS
43 - CHEM FEED SKIDS
44 - GLAND STEAM CONDENSER
45 - N2 STORAGE
46 - CO2 STORAGE
47 - CT FIRE PROTECTION SKID
48 - HYDROGEN STORAGE
49 - HP, IP, LP BYPASS VALVES
50 - WASTE WATER STORAGE
51 - OIL/WATER SEPARATOR
52 - DUCT BURNER SKID
53 - SCANNER AIR SKID
54 - CEMS
55 - WAREHOUSE
56 - NEW WELL
57 - AMMONIA FLOW CONTROL UNIT
58 - FUEL GAS PERFORMANCE HEATER
59 - PDC/ELECTRICAL ROOM
60 - EVAP POND
61 - BRINE CONCENTRATOR

0 40 80 160 240
1"= 80'

FIGURE 2-2a
General Arrangement
Sonoran Energy Project
Riverside County, California

Source: Power Engineers, Drawing MSK1-1, Rev. D, 12/23/14.

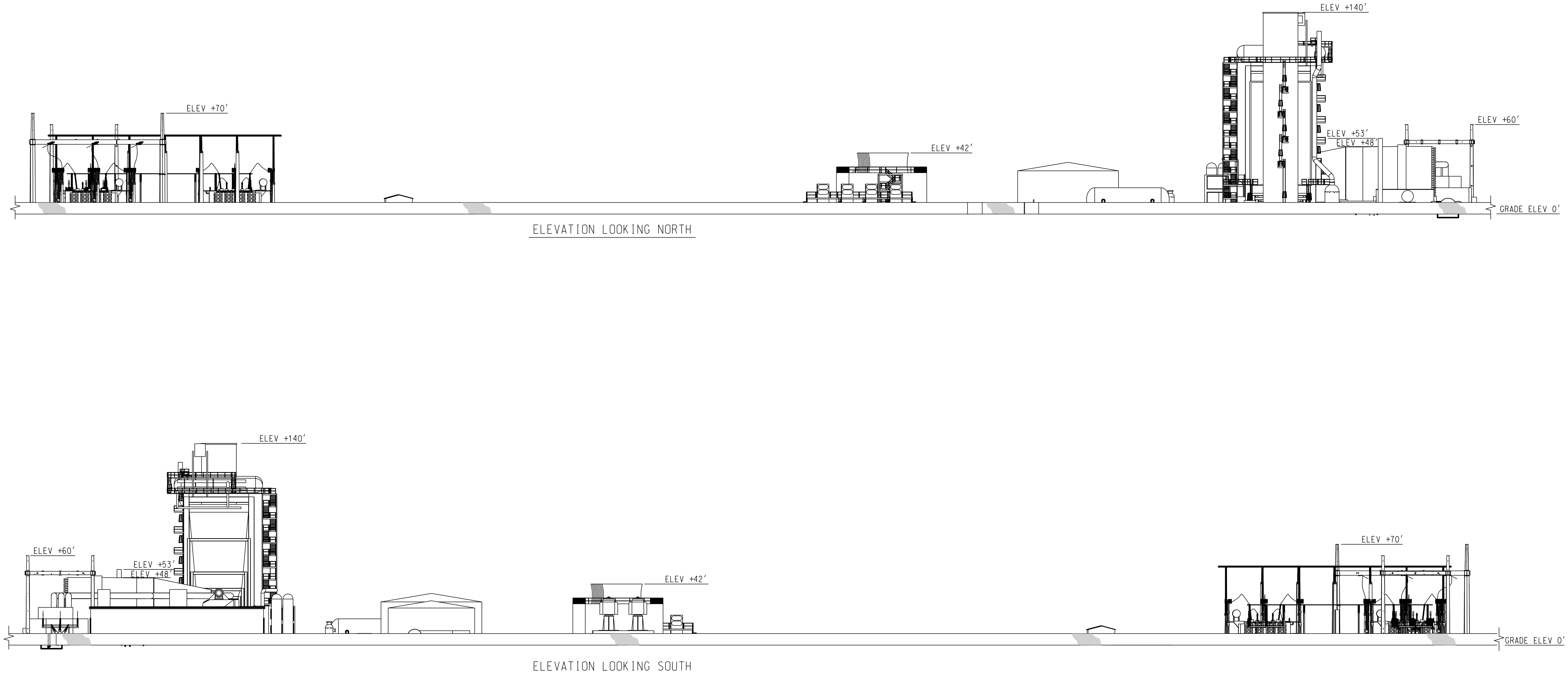
CH2MHILL.

EG0406151004SAC Figure_2-2A.ai 07.06.2015 dash

FIGURE 2-2b
General Arrangement with 161 kV Interconnection
Sonoran Energy Project
Riverside County, California

Source: Power Engineers, Drawing TSK1-1, Rev. A, 07/02/15.

CH2MHILL.



Source: Power Engineers, Drawing MSK1-2, Rev. C, 07/06/15.

FIGURE 2-3a
Elevation Drawings (Looking North and South)
Sonoran Energy Project
Riverside County, California

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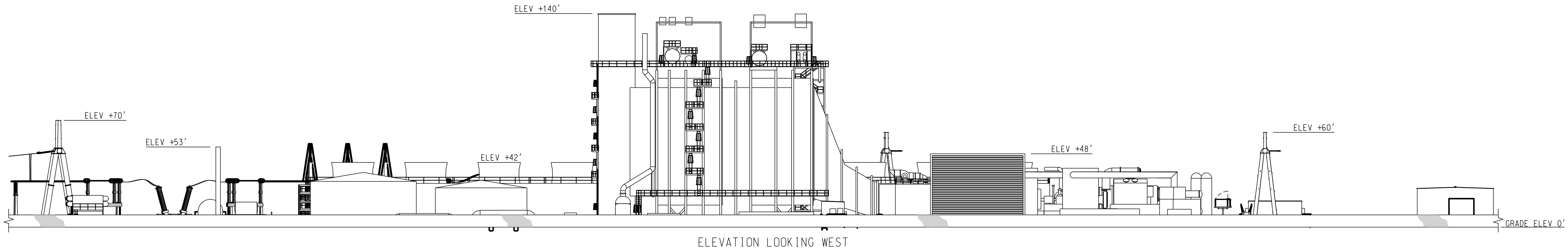
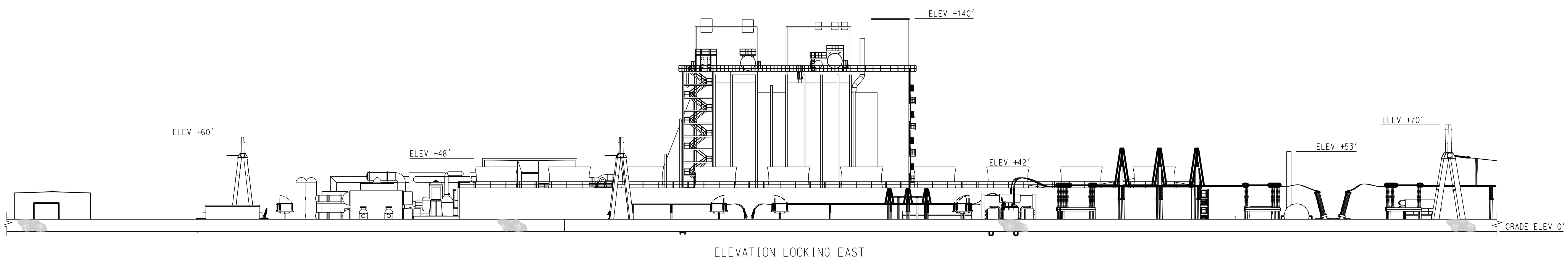
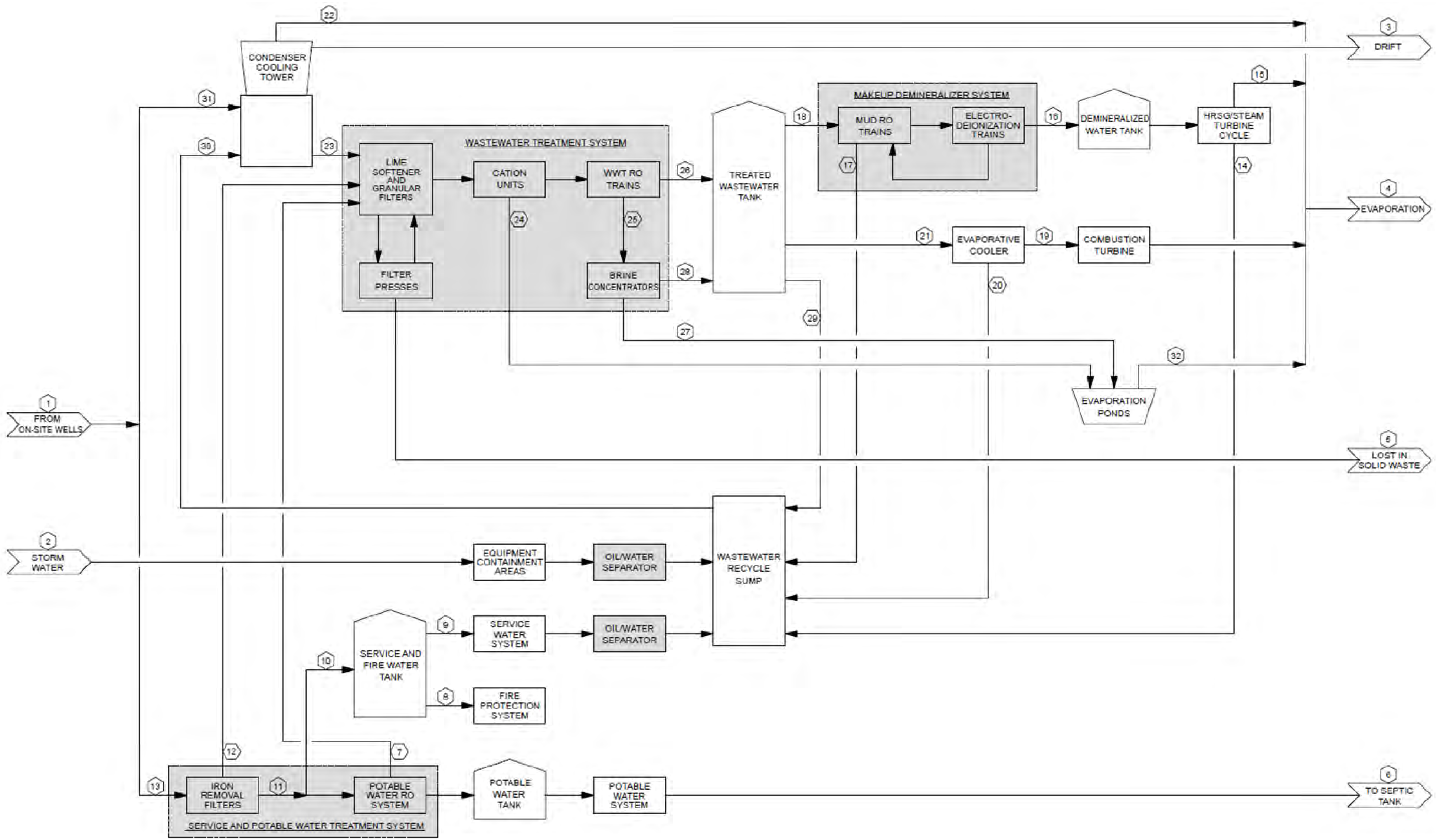




Source: Power Engineers, Drawing MSK1-3, Rev. C, 07/06/15.

FIGURE 2-3b
Elevation Drawings (Looking West and East)
Sonoran Energy Project
Riverside County, California



Source: Power Engineers, Drawing M2-2-1, Rev. A, 12/17/14.

FIGURE 2-4a
Water Balance Diagram
Sonoran Energy Project
Riverside County, California

NUMBER	DESCRIPTION								
	HEAT BALANCE CASE	29	30	31	32	33	34	35	36
	AMBIENT TEMPERATURE, DEG. F	59	59	74	74	110	110	122	122
	RELATIVE HUMIDITY, %	60	60	60	60	60	60	60	60
	DUCT FIRING	ON	OFF	ON	OFF	ON	OFF	ON	OFF
	EVAPORATIVE COOLERS	ON	ON	ON	ON	ON	ON	ON	ON
	LOAD	100	100	100	100	100	100	100	100
		AVERAGE FLOW RATE - GALLONS PER MINUTE							
1	RAW WATER FROM WELLS	1,675	1,473	1,804	1,587	2,227	1,977	2,345	2,071
2	STORM WATER	0	0	0	0	0	0	0	0
3	COOLING TOWER DRIFT	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
4	TOTAL EVAPORATION LOSSES	1,672	1,469	1,801	1,584	2,224	1,973	2,342	2,067
5	WATER LOST IN SOLID WASTE	0.8	0.7	0.9	0.8	1.0	0.9	1.1	1.0
6	SANITARY WASTEWATER DISCHARGED TO SEPTIC TANK	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
7	POTABLE WATER REVERSE OSMOSIS REJECT	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	FIRE PROTECTION	0	0	0	0	0	0	0	0
9	MISCELLANEOUS SERVICE WATER USES	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
10	TOTAL SERVICE AND FIRE WATER	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
11	TOTAL WATER PRODUCED BY IRON REMOVAL FILTERS	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7
12	IRON REMOVAL FILTER BACKWASH	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
13	WELL WATER SUPPLIED TO IRON REMOVAL FILTERS	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
14	HRSG BLOWDOWN	43.8	39.0	43.8	38.9	44.7	39.9	44.6	39.7
15	MISCELLANEOUS LOSSES FROM HRSG/ STEAM TURBINE CYCLE	21.9	19.5	21.9	19.4	22.3	20.0	22.3	19.8
16	DEMINERALIZED WATER PRODUCED	65.8	58.5	65.6	58.3	67.0	59.9	66.9	59.5
17	MAKEUP DEMINERALIZER REVERSE OSMOSIS REJECT	7.3	6.5	7.3	6.5	7.4	6.7	7.4	6.6
18	TREATED WASTE WATER TO MAKEUP DEMINERALIZER SYSTEM	73.1	65.0	72.9	64.8	74.5	66.5	74.4	66.1
19	EVAPORATION FROM EVAPORATIVE COOLER	16.9	16.9	39.2	39.2	87.7	87.7	93.9	93.9
20	BLOWDOWN FROM EVAPORATIVE COOLER	1.9	1.9	4.4	4.4	9.7	9.7	10.4	10.4
21	MAKEUP TO EVAPORATIVE COOLER	18.7	18.7	43.5	43.5	97.4	97.4	104.3	104.3
22	COOLING TOWER EVAPORATION	1618	1419	1724	1511	2094	1848	2204	1935
23	COOLING TOWER BLOWDOWN	404	354	430	377	523	461	551	483
24	CATION REGENERATION WASTEWATER	6.1	5.3	6.5	5.7	7.8	6.9	8.3	7.2
25	WASTEWATER REVERSE OSMOSIS REJECT	23.4	20.5	24.9	21.9	30.3	26.7	31.9	28.0
26	WASTEWATER REVERSE OSMOSIS PERMEATE	374	329	399	350	485	428	510	448
27	REJECT FROM BRINE CONCENTRATORS	9.4	8.2	10.0	8.7	12.1	10.7	12.8	11.2
28	DISTILLATE FROM BRINE CONCENTRATORS	14.0	12.3	15.0	13.1	18.2	16.0	19.1	16.8
29	TREATED WASTEWATER TO RECYCLE SUMP	297	257	297	254	331	280	351	294
30	WASTEWATER RECYCLED TO COOLING TOWER	353	308	356	307	396	339	416	354
31	COOLING TOWER MAKEUP FROM ON-SITE WELLS	1,669	1,467	1,799	1,581	2,222	1,971	2,340	2,065
32	EVAPORATION FROM EVAPORATION PONDS	15.4	13.5	16.4	14.4	20.0	17.6	21.0	18.4

NOTES: 1. THE ABOVE IS BASED ON NO STORMWATER FLOW.
2. THE ABOVE IS BASED ON FIVE (5) CYCLES OF CONCENTRATION IN THE COOLING TOWER. COOLING WATER TDS WOULD BE APPROXIMATELY 5,000 PPM.
3. WITH AN AVERAGE EVAPORATION RATE OF APPROXIMATELY 18 GPM, A NET EVAPORATION LOSS FROM A POND OF APPROXIMATELY 50 INCHES PER YEAR, AND OPERATION FOR 5 DAYS OUT OF 7, TOTAL AREA REQUIRED FOR THE EVAPORATION PONDS WOULD BE APPROXIMATELY 5 ACRES.

Source: Power Engineers, Drawing M2-2-2, Rev. A, 12/17/14.

FIGURE 2-4b
Water Balance Table
Sonoran Energy Project
Riverside County, California

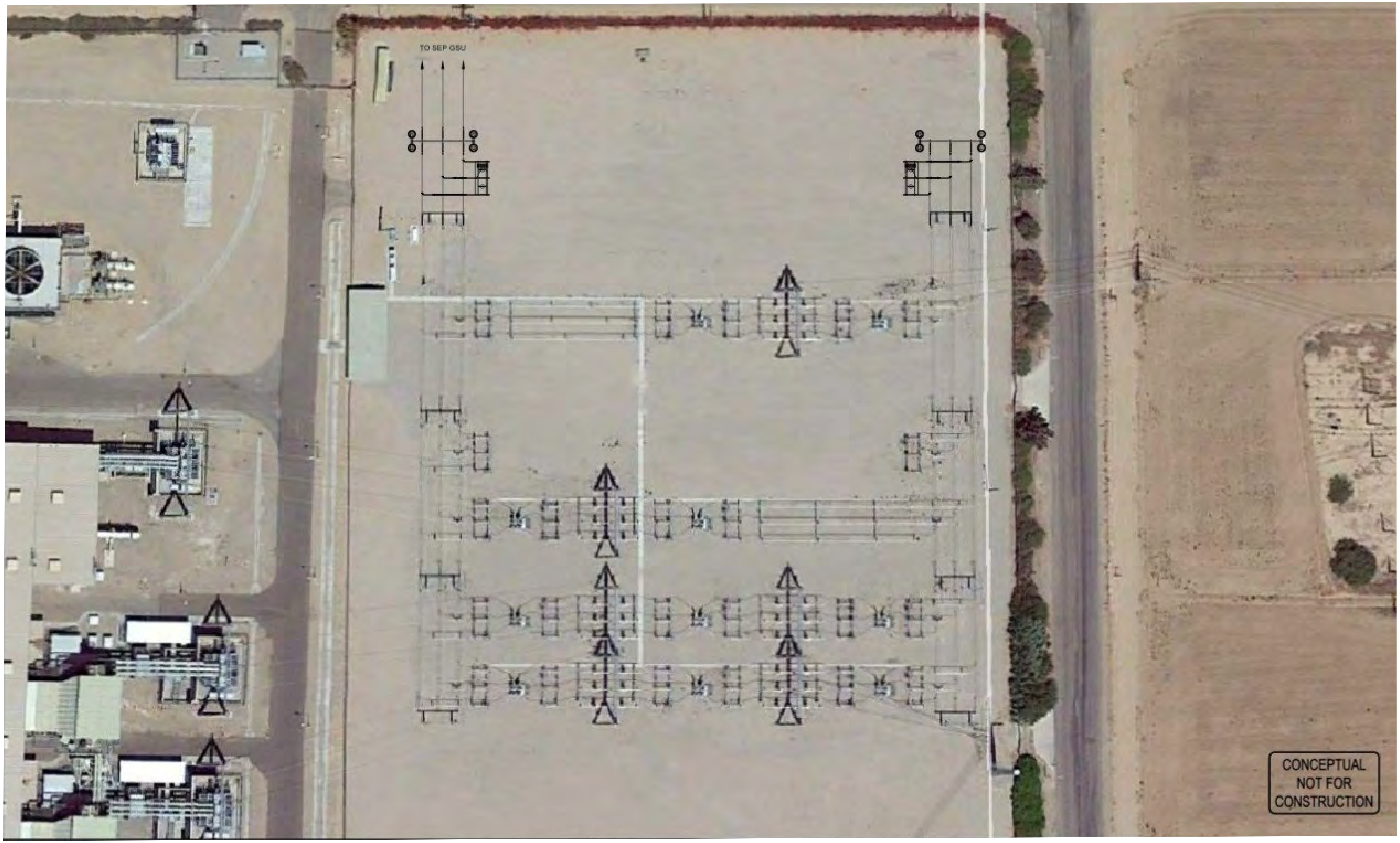


FIGURE 2-5
Electrical 161-kV General Arrangement
Buck Termination Diagram
Sonoran Energy Project
Riverside County, California

Source: Power Engineers, Drawing E1-1, Rev. 0, 2/2015.

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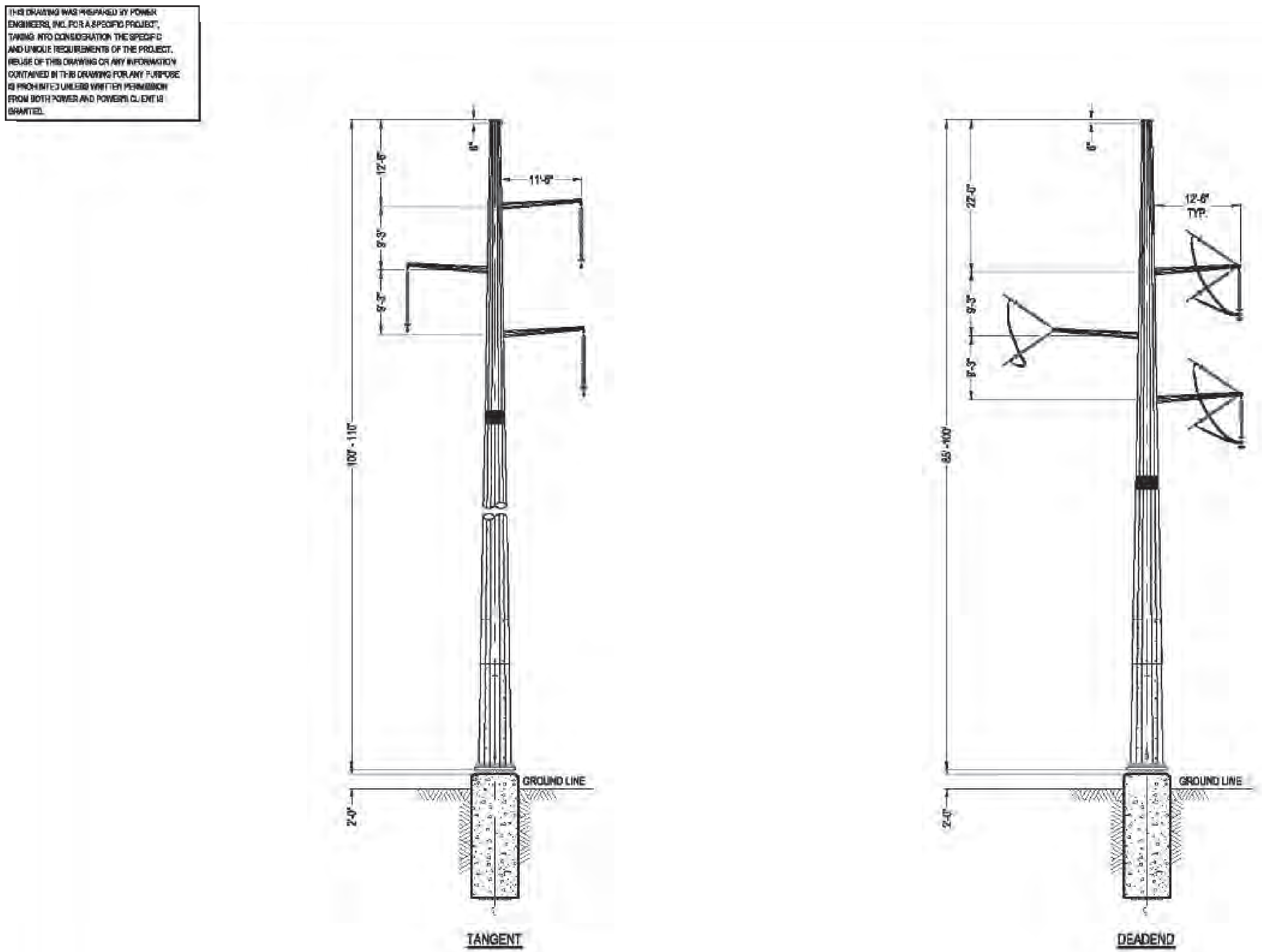

FIGURE 2-6
Typical Support Tower Designs
Sonoran Energy Project
Riverside County, California

Source: Power Engineers, Drawing DWG-1.

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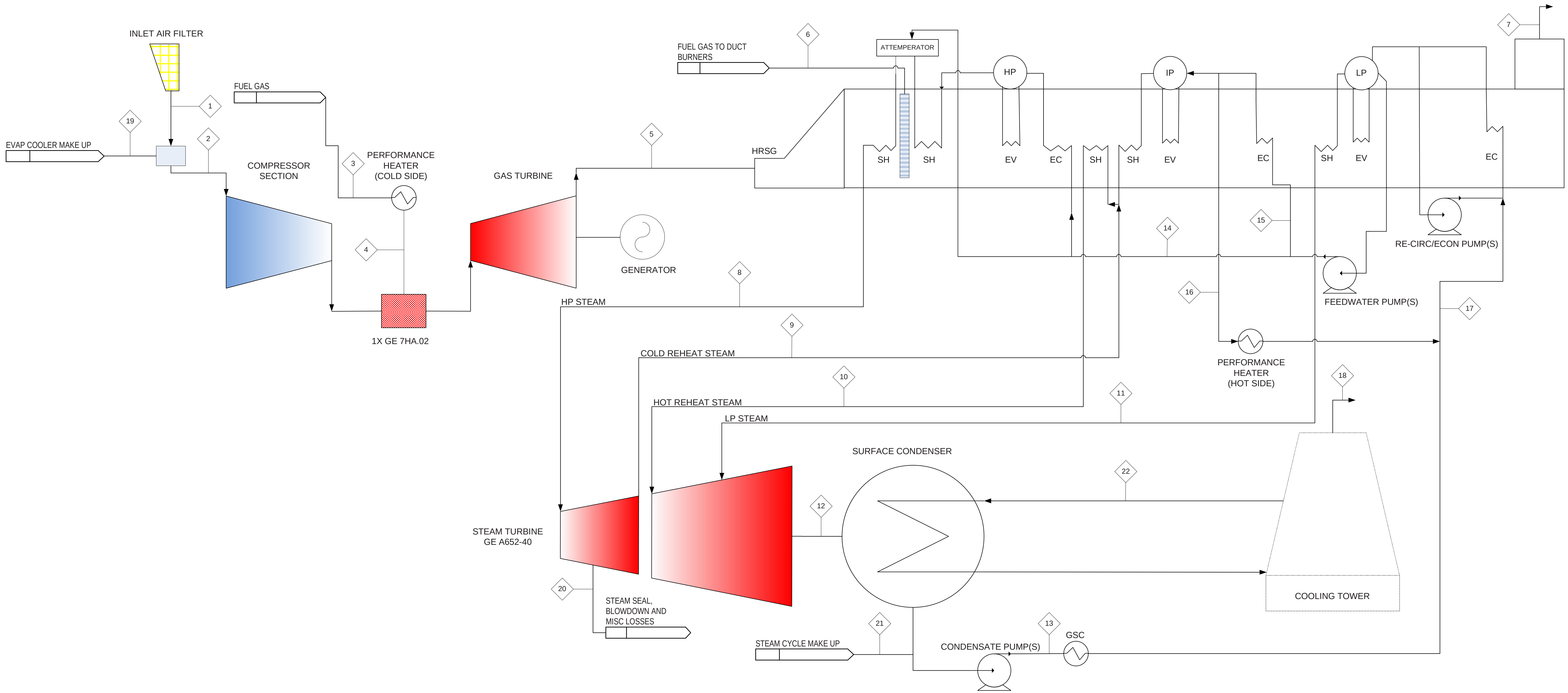

NOTES:

1. ALL CASES SHOW ONE GE 7HA.02 TURBINE IN OPERATION AT 100% LOAD
2. THE GAS TURBINE AND STEAM TURBINE ARE IN A SINGLE SHAFT ARRANGEMENT
3. THE HRSG SUPERHEATER, ECONOMIZER AND EVAPORATOR SECTIONS ARE SIMPLIFIED FOR CLARITY AND DO NOT REPRESENT ACTUAL LOCATIONS OR QUANTITIES WITHIN THE HRSG
4. COOLING TOWER EVAPORATION AND CIRCULATING WATER FLOWRATES ARE SHOWN IN GPM
5. NET PLANT OUTPUT IS SHOWN WITH ZERO BLOWDOWN AND ZERO STEAM CYCLE MAKEUP

Source: Power Engineers, Drawing M2-1-1, Rev. C, 4/27/15.

FIGURE 2-7a
Heat and Mass Balance Diagram
Sonoran Energy Project
Riverside County, California

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PLANT PERFORMANCE SUMMARY										
DESCRIPTION	CASE 20767	CASE 20769	CASE 20758	CASE 20759	CASE 20761	CASE 20762	CASE 20764	CASE 20765	CASE 19950	CASE 19949
PLANT GROSS OUTPUT, KW	548,477.0	519,905.0	543,923.0	515,193.0	525,291.0	496,258.0	526,546.0	497,325.0	514,585.0	484,768.0
ESTIMATED PLANT AUXILIARY POWER, KW	17,551.3	15,597.2	17,405.5	15,455.8	15,758.7	14,143.4	15,796.4	14,173.8	15,437.6	13,815.9
PLANT NET OUTPUT, KW	530,925.7	504,307.9	526,517.5	499,737.2	509,532.3	482,114.6	510,749.6	483,151.2	499,147.5	470,952.1
FUEL INPUT GAS TURBINE, MMBTU/HR (LHV)	2,923.6	2,923.6	2,853.6	2,853.6	2,738.9	2,738.9	2,757.6	2,757.6	2,699.4	2,699.4
FUEL INPUT GAS TURBINE, MMBTU/HR (HHV)	3,239.2	3,239.2	3,161.8	3,161.8	3,034.7	3,034.6	3,055.4	3,055.4	2,990.9	2,990.9
FUEL TO DUCT BURNER, MMBTU/HR (LHV)	200.0	0.0	200.0	0.0	200.0	0.0	200.0	0.0	200.0	0.0
FUEL TO DUCT BURNER, MMBTU/HR (HHV)	221.6	0.0	221.6	0.0	221.6	0.0	221.6	0.0	221.6	0.0
PLANT NET HEAT RATE, BTU/KWH (LHV)	5,883.2	5,797.2	5,799.7	5,710.2	5,767.9	5,681.0	5,790.7	5,707.6	5,808.7	5,731.8
PLANT NET HEAT RATE, BTU/KWH (HHV)	6,518.5	6,423.1	6,426.0	6,326.8	6,390.7	6,294.4	6,416.0	6,323.9	6,436.0	6,350.7
PLANT THERMAL EFFICIENCY, % (LHV)	58.0%	58.9%	58.8%	59.8%	59.2%	60.1%	58.9%	59.8%	58.7%	59.5%

STREAM NUMBER				1	2	3	4	6	7	8	9	10
DESCRIPTION				Air Entering Evap Cooler	Air Entering Gas Turbine	Fuel Gas to Performance Heater	Fuel Gas to Gas Turbine	Fuel Gas to Duct Burners	Exhaust Gas Leaving Stack	HP Steam leaving HRSG	CRH Steam Leaving ST	HRH Steam Leaving HRSG
CASE: 20767 0° F 50% RH	100% GTG LOAD EVAP: OFF DB: 200 MM BTU/hr	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,342.30	662.36	614.41
		TEMPERATURE	° F	0.00	0.00	60.00	440.00	80.00	156.70	1,052.90	704.70	1,057.80
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,497.20	1,350.70	1,548.50
		TOTAL FLOW	LBM/HR	5,640.90	5,640.90	141.70	141.70	9.70	5,810.30	869.40	854.00	915.70
CASE: 20769 0° F 50% RH	100% GTG LOAD EVAP: OFF DB: OFF	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	1,910.24	557.96	518.43
		TEMPERATURE	° F	0.00	0.00	60.00	440.00	-	167.60	1,066.10	728.00	1,064.00
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,517.90	1,370.20	1,554.40
		TOTAL FLOW	LBM/HR	5,640.90	5,640.90	141.70	141.70	-	5,800.60	695.50	682.80	768.50
CASE: 20758 39° F 47% RH	100% GTG LOAD EVAP: OFF DB: 200 MM BTU/Hr	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,441.29	682.06	632.57
		TEMPERATURE	° F	39.00	39.00	80.00	440.00	80.00	154.90	1,089.10	731.40	1,095.70
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,517.50	1,365.30	1,568.80
		TOTAL FLOW	KPPH	5,457.60	5,457.60	138.30	138.30	9.70	5,623.10	893.80	878.20	930.60
CASE: 20759 39° F 47% RH	100% GTG LOAD EVAP: OFF DB: OFF	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,010.15	578.46	537.37
		TEMPERATURE	° F	39.00	39.00	80.00	440.00	-	163.30	1,102.80	754.60	1,102.20
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,537.60	1,384.10	1,574.70
		TOTAL FLOW	KPPH	5,457.60	5,457.60	138.30	138.30	-	5,613.50	723.00	709.90	786.50
CASE: 20761 74° F 31% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,422.68	673.54	624.52
		TEMPERATURE	° F	74.00	58.00	80.00	440.00	80.00	157.80	1,101.50	740.90	1,107.60
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,526.00	1,371.30	1,575.50
		TOTAL FLOW	KPPH	5,256.30	5,273.30	132.70	132.70	9.70	5,415.60	882.00	866.70	914.70
CASE: 20762 74° F 31% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	1,990.95	570.54	529.97
		TEMPERATURE	° F	74.00	58.00	80.00	440.00	-	167.80	1,114.50	763.80	1,113.30
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,545.30	1,389.60	1,580.90
		TOTAL FLOW	KPPH	5,256.30	5,273.20	132.70	132.70	-	5,405.90	712.60	699.70	772.60
CASE: 20764 110° F 13% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,472.53	688.64	638.67
		TEMPERATURE	° F	110.00	74.00	80.00	440.00	80.00	162.60	1,098.30	738.10	1,105.50
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,522.60	1,368.90	1,574.00
		TOTAL FLOW	KPPH	5,383.70	5,401.20	133.60	133.60	9.70	5,544.50	902.30	886.50	936.20
CASE: 20765 110° F 13% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,042.15	585.50	543.90
		TEMPERATURE	° F	110.00	74.00	80.00	440.00	-	175.70	1,112.20	761.40	1,112.00
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,542.60	1,387.50	1,579.90
		TOTAL FLOW	KPPH	5,383.70	5,401.20	133.60	133.60	-	5,534.80	732.30	719.10	793.50
CASE: 19950 122° F 15% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,463.69	684.35	634.60
		TEMPERATURE	° F	122.00	83.00	80.00	440.00	80.00	164.40	1,105.03	743.60	1,112.20
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,527.30	1,372.30	1,577.80
		TOTAL FLOW	KPPH	5,269.30	5,286.40	130.80	130.80	9.70	5,426.90	896.20	880.60	928.00
CASE: 19949 122° F 15% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	14.52	14.39	544.70	-	-	14.52	2,018.54	581.60	540.78
		TEMPERATURE	° F	122.00	83.00	80.00	440.00	-	178.00	1,114.50	764.90	1,113.40
		ENTHALPY	BTU/LBM	-	-	-	-	-	-	1,544.60	1,389.60	1,580.70
		TOTAL FLOW	KPPH	5,269.30	5,286.40	130.80	130.80	-	5,417.20	722.40	709.30	788.50

STREAM NUMBER				11	12	13	14	15	16	17	18	19	20	21	22
DESCRIPTION				LP Steam Leaving HRSG	Steam Turbine Exhaust	Condensate Pump Flow	Feedwater Pump HP Flow	Feedwater Pump IP Takeoff	IP FW to Performance Heater	Total Condensate Flow	Cooling Tower Evaporation (GPM)	EVAP Cooler Makeup	Steam Seal, BD and Misc losses	Steam Cycle Make up	Circulating Water (GPM)
CASE: 20767 0° F 50% RH	100% GTG LOAD EVAP: OFF DB: 200 MM BTU/hr	PRESSURE	PSIA	88.45	0.44	-	2,997.14	924.98	877.29	-	-	-	-	-	27.26
		TEMPERATURE	° F	592.90	75.70	76.30	326.90	322.00	477.70	78.50	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,326.80	1,002.10	-	302.60	293.90	461.80	-	-	-	-	-	-
		TOTAL FLOW	LBM/HR	96.30	1,022.70	1,027.40	867.90	145.50	83.80	1,111.20	1,352.95	0.00	0.00	0.00	129,480.00
CASE: 20769 0° F 50% RH	100% GTG LOAD EVAP: OFF DB: OFF	PRESSURE	PSIA	83.25	0.42	-	3,164.26	962.77	911.62	-	-	-	-	-	27.26
		TEMPERATURE	° F	579.20	74.10	74.90	324.20	318.60	471.10	78.30	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,320.40	1,007.20	-	300.20	290.50	454.30	-	-	-	-	-	-
		TOTAL FLOW	LBM/HR	120.30	897.50	901.60	964.00	172.70	87.00	988.50	1,212.78	0.00	0.00	0.00	129,480.00
CASE: 20758 39° F 47% RH	100% GTG LOAD EVAP: OFF DB: 200 MM BTU/Hr	PRESSURE	PSIA	88.65	0.51	-	2,970.21	920.83	874.38	-	-	-	-	-	27.26
		TEMPERATURE	° F	594.70	80.10	80.70	326.80	322.00	477.40	82.50	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,327.70	1,007.90	-	302.40	293.90	461.50	-	-	-	-	-	-
		TOTAL FLOW	KPPH	86.80	1,028.40	1,033.00	892.30	134.20	81.80	1,114.80	1,368.00	0.00	0.00	0.00	129,480.00
CASE: 20759 39° F 47% RH	100% GTG LOAD EVAP: OFF DB: OFF	PRESSURE	PSIA	83.03	0.44	-	3,145.33	958.71	909.03	-	-	-	-	-	27.26
		TEMPERATURE	° F	582.10	75.80	76.50	323.60	318.20	471.10	79.60	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,321.90	1,012.50	-	299.50	290.00	454.30	-	-	-	-	-	-
		TOTAL FLOW	KPPH	110.30	905.90	909.90	721.50	161.40	87.70	994.70	1,230.00	0.00	0.00	0.00	129,480.00
CASE: 20761 74° F 31% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	87.82	0.77	-	2,987.89	926.37	880.63	-	-	-	-	-	27.26
		TEMPERATURE	° F	591.50	93.20	93.90	326.20	321.40	475.20	94.70	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,326.20	1,011.50	-	301.90	293.30	459.00	-	-	-	-	-	-
		TOTAL FLOW	KPPH	87.20	1,012.70	1,017.30	880.50	127.20	79.20	1,096.50	1,724.00	18.90	0.00	0.00	129,480.00
CASE: 20762 74° F 31% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	81.61	0.69	-	3,156.27	961.90	913.05	-	-	-	-	-	27.26
		TEMPERATURE	° F	579.90	89.50	90.30	3,225.00	317.00	468.90	92.30	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,320.90	1,015.90	-	298.40	288.80	451.70	-	-	-	-	-	-
		TOTAL FLOW	KPPH	107.60	889.10	893.10	710.80	155.10	82.20	975.20	1,511.00	18.90	0.00	0.00	129,480.00
CASE: 20764 110° F 13% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	91.05	1.05	-	2,959.24	921.23	875.43	-	-	-	-	-	27.26
		TEMPERATURE	° F	592.40	103.40	104.00	328.80	324.00	478.20	104.00	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,326.40	1,018.20	-	304.50	296.00	462.40	-	-	-	-	-	-
		TOTAL FLOW	KPPH	95.40	1,042.60	1,047.30	900.80	128.30	78.60	1,125.90	2,094.00	42.10	0.00	0.00	129,480.00
CASE: 20765 110° F 13% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	83.99	0.95	-	3,138.42	958.30	909.35	-	-	-	-	-	27.26
		TEMPERATURE	° F	582.10	100.00	100.70	324.40	319.00	471.90	101.60	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,321.80	1,023.50	-	300.30	290.90	455.20	-	-	-	-	-	-
		TOTAL FLOW	KPPH	111.40	913.90	918.00	730.80	155.70	81.30	999.30	1,848.00	42.10	0.00	0.00	129,480.00
CASE: 19950 122° F 15% RH	100% GTG LOAD EVAP: ON DB: 200 MM BTU/Hr	PRESSURE	PSIA	90.43	1.25	-	2,968.51	923.97	878.53	-	-	-	-	-	27.26
		TEMPERATURE	° F	590.90	109.20	109.90	328.30	323.50	477.00	109.40	-	59.00	-	59.00	79.00
		ENTHALPY	BTU/LBM	1,325.70	1,027.30	-	304.00	295.50	461.00	-	-	-	-	-	-
		TOTAL FLOW	KPPH	94.50	1,033.50	1,038.10	894.70	127.70	77.30	1,115.40	2,204.00	44.90	0.00	0.00	129,480.00
CASE: 19949 122° F 15% RH	100% GTG LOAD EVAP: ON DB: OFF	PRESSURE	PSIA	83.21	1.13	-	3,146.25	959.50	910.90	-	-	-	-	-	27.26
		TEMPERATURE	° F	581.10	106.00	106.80	323.70	318.30	471.20	107.10	-	59.00	-	-	79.00
		ENTHALPY	BTU/LBM	1,321.40	1,032.50	-	299.70	290.20	454.40	-	-	-	-	-	-
		TOTAL FLOW	KPPH	109.40	907.00	911.00	718.00	159.00	79.80	990.80	1,935.00	44.90	0.00	0.00	129,480.00

Source: Power Engineers, Drawing M2-1-2, Rev. A, 4/27/15.

FIGURE 2-7b
Heat and Mass Balance Table
Sonoran Energy Project
Riverside County, California

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Environmental Analysis of Project Modification

The project modification discussed herein will not cause additional impacts beyond those identified in the Commission's Final Decision (02-AFC-01C), as amended. Any potential impacts associated with the proposed modification will be less than significant.

3.1 Air Quality

This section of the PTA describes and evaluates the air quality effects of the proposed project modification. Some air quality-related data are presented in other sections of this PTA, including an evaluation of toxic air pollutants (see Section 3.8, Public Health) and information relating to the fuel characteristics, heat rate, and startup and operating limits of the SEP (see Section 2, Project Description).

The currently licensed design is a nominal 569-MW combined-cycle power plant, consisting of two Siemens SGT6-5000F combined-cycle gas turbines with Flex Plant ™ 30 rapid start technology, a 60 MMBtu/hr auxiliary boiler, a mechanical-draft wet cooling tower, a diesel-powered fire water pump, and ancillary facilities. The project owner proposes to modify the project as follows:

- Define a new point of electrical interconnection via an approximately 1,320-foot, 161-kV transmission line to the Western Area Power Administration's Blythe substation located southeast of the project site via an existing transmission line located in the SCE Buck Boulevard substation.
- Replace the two Siemens SGT6-5000F combustion turbines with a single, more efficient GE Frame 7HA.02 combustion turbine.
- Replace the Siemens STG with a more efficient single-shaft GE D652 STG.
- Increase the size of the auxiliary boiler to support GE's rapid response fast start capability.
- Decrease the size of cooling tower from an 11-cell to a 10-cell tower in response to the reduced heat rejection requirements.
- Decrease the size of the emergency diesel fire pump engine.

A comprehensive project description can be found in Section 2, Project Description.

The project design will incorporate air pollution emission controls designed to meet expected Mojave Desert Air Quality Management District (MDAQMD or District) best available control technology (BACT) determinations. These controls will include dry low-NOx combustors in the CTG to limit NOx production, SCR with aqueous ammonia for additional NOx reduction in the HRSG, and an oxidation catalyst to control CO and toxic air contaminant (TAC) emissions. Fuels to be used will be pipeline-specification natural gas in the turbine/HRSG and auxiliary boiler, and California low sulfur diesel fuel in the fire pump engine. Low NOx burners will be incorporated into the HRSG duct burners and auxiliary boiler. The cooling tower will be equipped with high-efficiency drift eliminators. Based upon the new project design, the project will result in a net decrease in annual emissions of all pollutants compared with the currently licensed configuration.

At the same time, the adjacent operating BEP is proposing to reduce the allowable PM_{10} emissions from its existing gas turbines to 6.2 pounds per hour per turbine and 56.9 tons per year (facility total) from the current limits of 11.5 pounds per hour and 97 tons per year. BEP will also reduce allowable annual SO_2 emissions from 24 to 12 tons per year by limiting the annual average sulfur content of the natural gas fuel.

Because BEP and SEP are part of the same stationary source for District permitting regulations, the air permit application to the District addresses both of these changes. However, because the two plants have separate licenses, a separate PTA is being submitted for the PM_{10} and SO_2 emissions reduction at BEP. Nevertheless, the analysis in this PTA incorporates the proposed reductions in emissions at BEP in the ambient air quality impact assessment and the evaluation of cumulative impacts and mitigation.

3.1.1 Project Description

3.1.1.1 Current Site and Facilities

The project is currently licensed as a nominally rated 569-MW combined cycle facility with a maximum output of 587 MW. The project is located within the City of Blythe, approximately 5 miles west of the center of the city. SEP will be located on a 76-acre site immediately adjacent to the existing, operational BEP. Figure 2-1 shows the general location of the project.

When BEP II was originally permitted by the MDAQMD, the project was under separate ownership from BEP. As a result, although both BEP and BEP II are located on contiguous property, they were permitted as separate stationary sources. Since both BEP and BEP II are now under common control (the holding companies for both plants are owned by AltaGas Power Holdings (U.S.) Inc. (APHUS), the two facilities are now considered to be a single stationary source under District and federal air permitting regulations. The regulatory implications of the single stationary source designation are discussed further in the regulatory setting and LORS compliance sections, below.

3.1.1.2 Geography and Topography

SEP is located approximately 5 miles west of downtown Blythe at the edge of the Palo Verde Mesa. The project site is at an elevation of approximately 350 feet above sea level. City zoning designations for lands within 1 mile of the power plant site are Agriculture (A) to the east, and Service Industrial (I-S) to the south between I-10 and Hobsonway (see Figure 2-1). The nearest complex terrain (terrain exceeding stack height) in relation to the project site is located in the San Joaquin Hills, approximately 5.5 miles (or approximately 9 kilometers [km]) to the east and southeast. The nearest Class I areas are the San Gabriel Wilderness and the Cucamonga Wilderness, which are approximately 43 miles (~70 km) north of the project site.

3.1.1.3 Climate and Meteorology

The climate of the Mojave Desert Air Basin is determined by its terrain and geographical location. The MDAQMD encompasses the desert portion of San Bernardino County and a portion of eastern Riverside County commonly known as the Palo Verde Valley. The MDAQMD covers more than 20,000 square miles and is characterized by hot, dry summers and mild winters, with little precipitation.

Consistent with the typical weather of the interior deserts of Southern California, eastern Riverside County in general has an arid climate characterized by very low precipitation, hot summers, and mild winters. Temperature inversions occur, but are not as strong as in coastal areas, where the marine influence is important. The area's climatic conditions are strongly influenced by the large-scale sinking and warming of air in the semi-permanent subtropical high-pressure center over the eastern Pacific. This high-pressure system effectively blocks out most mid-latitude storms, except in winter when the ridge is weaker and farther south. The coastal mountains to the west also have a major influence on climate, serving as a meteorological boundary that effectively removes moisture from the marine air flowing from the Pacific.

The nearest long-term meteorological station with available temperature and precipitation means and extremes is the National Weather Service Blythe Clean Air Act (CAA) Airport station. This weather station is located approximately one mile west of the Project at latitude 33°37'N, longitude 114°43'W. Data collected at this station over a 68-year period (1948-2015) are presented in Table 3.3-1.

Temperatures of 32°F or below rarely occur at this station, but temperatures of 100°F or above are more frequent, occurring from June through September.

Table 3.3-1. Average Temperature and Precipitation Data at Blythe (1948-2015)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
Average Max. Temperature (°F)	66.9	71.9	78.5	86.4	95.2	104.5	108.4	106.7	101.5	89.8	75.9	66.6	87.7
Average Min. Temperature (°F)	41.7	45.4	50.2	56.5	64.5	72.7	81.1	80.3	73.1	60.8	48.6	41.3	59.7
Average Total Precipitation (in.)	0.48	0.44	0.35	0.15	0.02	0.02	0.28	0.60	0.34	0.29	0.19	0.41	3.55

Source: Western Regional Climate Center (http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?ca0927)

Note: °F = degrees Fahrenheit

Eastern Riverside County receives a portion of its annual rainfall from November to March, when the semi-permanent high-pressure system over the eastern Pacific Ocean moves south, allowing storms to move through the area; and another portion of its annual rainfall at the height of summer, when the southwestern monsoon is present. In August, the boundary between the easterly, tropical trade winds and the mid-latitude westerlies sometimes moves north of the project site, and thunderstorms, sometimes even mesoscale convective complexes of thunderstorms, can be present in the vicinity. The average annual precipitation at the project site is about 3.6 inches. Monthly mean precipitation at Blythe ranges from 0.60 inches in August to 0.02 inches in May and June. Relative humidity levels are generally low. In the summer, relative humidity averages 20 to 40 percent in the early morning and 10 to 30 percent in the afternoon. In winter, relative humidity averages 30 to 50 percent in the early morning and 10 to 30 percent in the afternoon.

Local wind circulations are channeled north-south by the presence of the Colorado River Valley. Winds are typically of light to moderate strength from either the northwest or the southwest, and channeled by the river valley. Composite annual and quarterly wind roses are shown in Figures 3.1-1 through 3.1-5. Individual annual and quarterly wind roses and quarterly wind frequency distributions for the project area are provided in Appendix 3.1A.

3.1.2 Background Air Quality

The U.S. Environmental Protection Agency (EPA) has established national ambient air quality standards (NAAQS) for the following seven pollutants, termed criteria pollutants: ozone, nitrogen dioxide (NO_2), CO, sulfur dioxide (SO_2), particulate matter with aerodynamic diameter less than or equal to 10 microns (PM_{10}), particulate matter with aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$), and airborne lead. The federal CAA requires EPA to designate areas as attainment or nonattainment with respect to each criteria pollutant, depending on whether the areas meet the NAAQS. An area that is designated nonattainment means the area is not meeting the NAAQS and is subject to planning requirements to attain the standard.

In addition to the seven pollutants listed above, the California Air Resources Board (ARB) has established state standards for visibility-reducing particles, sulfates, hydrogen sulfide, and vinyl chloride. Similar to EPA, ARB designates areas in California as attainment or nonattainment with respect to the California ambient air quality standards (CAAQS). The state standards were designed to protect the most sensitive members of the population, such as children, the elderly, and people who suffer from lung or heart diseases.

Both state and federal air quality standards are based on two variables: maximum concentration and an averaging time over which the concentration will be measured. Maximum concentrations were based on levels that may have an adverse effect on human health. The averaging times were based on whether the damage caused by the pollutant will occur during exposures to a high concentration for a short time (for example, 1 hour), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants, there is more than one air quality standard, reflecting both short-term and long-term effects. Table 3.1-2 presents the NAAQS and CAAQS.

Table 3.1-2. Ambient Air Quality Standards

Pollutant	Averaging Time	California	National
Ozone	1-hour	0.09 ppm (180 µg/m^3)	—
	8 hour	0.07 ppm (137 µg/m^3)	0.075 ppm (147 µg/m^3)
CO	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)
	8-hour	9.0 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
NO_2	1-hour	0.18 ppm (339 µg/m^3)	100 ppb (188 µg/m^3) (a)
	Annual arithmetic mean	0.030 ppm (57 µg/m^3)	53 ppb (100 µg/m^3)
SO_2 (b)	1-hour	0.25 ppm (655 µg/m^3)	75 ppb (196 µg/m^3)
	3-hour (secondary standard)	—	0.5 ppm (1,300 µg/m^3)
	24-hour	0.04 ppm (105 µg/m^3)	—
Respirable Particulate Matter (PM_{10})	24-hour	50 µg/m^3	150 µg/m^3
	Annual arithmetic mean	20 µg/m^3	—
Fine Particulate Matter ($PM_{2.5}$)	24-hour	—	35 µg/m^3 (c)
	Annual arithmetic mean	12 µg/m^3	12.0 µg/m^3 (d)
Sulfates	24-hour	25 µg/m^3	—
Lead	30-day average	1.5 µg/m^3	—
	Calendar quarter	—	1.5 µg/m^3
	Rolling 3-month average		0.15 µg/m^3
Hydrogen sulfide (H_2S)	1- hour	0.03 ppm (42 µg/m^3)	—
Vinyl chloride	24-hour	0.010 ppm (26 µg/m^3)	—
Visibility-reducing particles	8-hour (10 a.m. to 6 p.m. PST)	Insufficient amount to produce an extinction coefficient of 0.23 per kilometer because of particles when the relative humidity is less than 70 percent.	—

[a] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 ppb.

[b] On June 2, 2010, EPA established a new 1-hour SO_2 standard, effective August 23, 2010, which is based on the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations. The EPA also revoked both the 24-hour SO_2 standard of 0.14 ppm and the annual primary SO_2 standard of 0.030 ppm, effective August 23, 2010. The secondary SO_2 standard was not revised at that time; however, the secondary standard is undergoing a separate review by EPA.

[c] The 24-hour standard is attained when 98 percent of the daily concentrations, averaged over 3 years, are equal to or less than the standard.

[d] 3-year average of the weighted annual mean concentrations.

µg/m3	=	microgram(s) per cubic meter
ppm	=	parts per million
ppb	=	parts per billion

Source: ARB, 2012a

The federal CAA requires EPA to classify areas in the country as attainment or nonattainment, with respect to each criteria pollutant, depending on whether they meet the national standards. In addition, ARB makes area designations within California for state ambient air quality standards (AAQS). The attainment status at the project site for both the NAAQS and CAAQS are listed in Table 3.1-3.

Table 3.1-3. State and Federal Air Quality Designations for the Project Area

Pollutant	State Designation	Federal Designation
Ozone	Nonattainment (Moderate)	Unclassified/attainment
CO	Unclassified	Unclassified/attainment
NO_2	Attainment	Unclassified/attainment
SO_2	Attainment	Unclassified/attainment
PM_{10}	Nonattainment	Unclassified
$PM_{2.5}$	Unclassified	Unclassified/attainment
Lead	Attainment	Unclassified/attainment
H_2S and Sulfates	Unclassified	N/A

Source: ARB, 2014.
N/A = not applicable

The MDAQMD is downwind of the Los Angeles basin, and to a lesser extent, is downwind of the San Joaquin Valley. Prevailing winds transport ozone and ozone precursors from both regions into and through the MDAB during the summer ozone season. These transport couplings have been officially recognized by ARB.[6] Local MDAQMD emissions contribute to exceedances of both the NAAQS and State Ambient Air Quality Standards for ozone, but photochemical ozone modeling conducted by the MDAQMD and ARB indicates that the MDAB will be in attainment of both standards without the influence of this transported air pollution from upwind regions.

The project site is a relatively remote rural area that is in attainment for most state and federal standards. Ambient air concentrations of ozone (O_3), NO_2, SO_2, CO, PM_{10}, and $PM_{2.5}$ are recorded at various monitoring stations in Riverside County. The closest ARB-certified monitoring site relative to the project site is located approximately 5 miles east of the project site in Blythe; only ozone is monitored at that location. The immediate area surrounding the project site (within 1.5 to 2 miles) is an area with sparse population. Further out, areas to the north, northwest, west, and southwest are all vacant with very sparse population. However, there are suburban areas with moderate residential areas more than 2 miles to the east (Blythe). The monitoring stations were generally positioned to represent area-wide ambient conditions rather than the localized impacts of any particular emission source or group of sources. In rural areas of the county, pollutant concentrations are not expected to vary dramatically from one location to the next, because the emission sources are few and widely distributed. Therefore, data from a single station are used to characterize air quality for each pollutant in the project area.

Ambient air quality monitoring data for ozone, PM_{10}, $PM_{2.5}$, CO, NO_2, and SO_2 were compared to the most stringent applicable standards for the years 2009 through 2014 at the most representative monitoring stations for each pollutant. Ozone data are from the Blythe-445 West Murphy Street monitoring station; PM_{10}, $PM_{2.5}$, NO_2, and CO data are from the Palm Springs Fire Station monitoring station; and SO_2 data are from the Riverside-Rubidoux monitoring station.[7] Airborne lead levels are

[6] In the publication “Ozone Transport: 2001 Review,” (ARB 2001), ARB identifies the South Coast Air Basin as having an overwhelming and significant impact on the Mojave Desert Air Basin (which includes the Mojave Desert) and the San Joaquin Valley as having an overwhelming impact on the MDAB.

[7] The project owner had originally proposed to use SO_2 data from the Victorville-14306 Park Avenue monitoring station to represent background concentrations in the project area. However, according to ARB’s “Recommended Area Designations for the 2010 Federal Sulfur Dioxide (SO2) Standard” staff report (June 2011; Appendix 1), the Victorville monitoring station is located near one of the Mojave Desert

taken from the San Bernardino-24302 4th Street monitoring station. The locations of these monitoring stations relative to the project site are shown in Figure 3.1-6.

The ambient air quality data are based on data published by ARB (ADAM Web site) and EPA (AIRS Web site). The maximum ambient background concentrations will be combined with the modeled concentrations and used for comparison to the AAQS.[8]

3.1.2.1 Nitrogen Dioxide

NO_2 is formed primarily from reactions in the atmosphere between NO (nitric oxide) and oxygen (O_2) or ozone. NO is formed during high-temperature combustion processes, when the nitrogen and O_2 in the combustion air combine. Although NO is much less harmful than NO_2, it can be converted to NO_2 in the atmosphere within a matter of hours, or even minutes, under certain conditions. The control of NO and NO_2 emissions is also important because of the role of both compounds in the atmospheric formation of ozone.

Table 3.1-4 shows NO_2 levels recorded at the Palm Springs station for the years 2009 through 2014. The Mojave Desert air basin is classified as an attainment area with respect to state ambient standards for NO_2 and an unclassified/attainment area with respect to national ambient standards for NO_2. During the period from 2009 to 2014, there were no violations of the CAAQS 1-hour standard (0.18 ppm) at any monitoring station in Riverside County. The highest 1-hour concentration recorded at the Palm Springs Fire Station monitoring station during the years 2009 to 2014 was 0.052 ppm in 2013. The federal 1-hour NO_2 standard is 0.100 ppm; to attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within Mojave Desert air basin must not exceed 0.100 ppm. Table 3.1-4 shows that there were no violations of the 1-hour or annual NAAQS or CAAQS at the Palm Springs Fire Station monitoring station during this period.

Table 3.1-4. Nitrogen Dioxide Levels at Palm Springs (ppm)

Palm Springs Fire Station Monitoring Station, Riverside County	2009	2010	2011	2012	2013	2014
Maximum 1-hour Average	0.048	0.046	0.044	0.045	0.052	0.046
98th Percentile 1-hour Average	0.039	0.039	0.039	0.039	0.039	0.041
Annual Average	0.008	0.008	0.008	0.007	0.007	0.007
Days Over State Standard (0.18 ppm, 1-hour)	0	0	0	0	0	0
Days Over Federal Standard (0.100 ppm, 1-hour) (a)	0	0	0	0	0	0

Sources: ARB ADAM Website (www.arb.ca.gov/adam/welcome.html).

[a] To attain the federal 1-hour average NO_2 standard of 0.100 ppm, the 3-year average of the 98th percentile of the daily maximum 1-hour average values at each monitor must not exceed 100 ppb.

3.1.2.2 Ozone

Ozone is an end-product of complex reactions between VOC and NOx in the presence of ultraviolet solar radiation. VOC and NOx emissions from vehicles and stationary sources, combined with daytime wind flow patterns, mountain barriers, temperature inversions, and intense sunlight, generally result in the highest O_3 concentrations. The entire Mojave Desert air basin is classified as a nonattainment area with respect to state ambient standards for ozone, and the project location within the air basin is an unclassified/attainment area with respect to national ambient standards for ozone. Table 3.1-5 shows

facilities that has SOx emissions in excess of 100 tons per year and is sited to capture high SO_2 concentrations. Therefore, SO_2 concentrations monitored at Victorville are not considered to be representative of concentrations in the Blythe area.

[8] Except for 1-hour average NO_2 and SO_2, and 24-hour average PM_{10}, for which the standards are statistically based. See Table 3.1-2.

the measured ozone levels at the Blythe monitoring station during the period from 2009 through 2014. The 1-hour ozone CAAQS of 0.09 ppm was not exceeded during this period.

The federal 8-hour ozone NAAQS requires that the 3-year average of the fourth-highest values for individual years be maintained at or below 0.075 ppm. Therefore, the number of days in each year with maximum 8-hour concentrations above the standard in Table 3.1-5 does not equate to the number of violations.

Table 3.1-5. Ozone Levels at Blythe (ppm)

Blythe Station, Riverside County	2009	2010	2011	2012	2013	2014
Maximum 1-hour Average	0.072	0.072	0.073	0.084	0.065	0.093
Number of Days Exceeding California 1-hour Standard (0.09 ppm)	0	0	0	0	0	0
Number of Days Exceeding Old National 1-hour Standard (0.12 ppm)[a]	0	0	0	0	0	0
Maximum 8-hour Average	0.066	0.068	0.068	0.077	0.061	0.084
Fourth Highest 8-hour Average	0.059	0.065	0.066	0.075	0.057	0.078
Number of Days Exceeding California 8-hour Standard (0.07 ppm)	0	0	0	12	0	16
Number of Days Exceeding National 8-hour Standard (0.075 ppm)[b]	0	0	0	2	0	8

Source: ARB ADAM Website (www.arb.ca.gov/adam/welcome.html).

[a] EPA revoked the 1-hour ozone standard in all areas in 1997, although some areas have continued obligations under that standard ("anti-backsliding").

[b] To attain this standard, the 3-year average of the fourth-highest maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm.

3.1.2.3 Sulfur Dioxide

SO_2 is produced by the combustion of any sulfur-containing fuel. It is also emitted by chemical plants that treat or refine sulfur or sulfur-containing chemicals. Natural gas contains nearly negligible sulfur, whereas fuel oils may contain much larger amounts. Because of the complexity of the chemical reactions that convert SO_2 to other compounds (such as sulfates), peak concentrations of SO_2 occur at different times of the year in different parts of California, depending on local fuel characteristics, weather, and topography. The Mojave Desert air basin is considered to be in attainment with respect to the state air quality standard and unclassified with respect to the federal air quality standard for SO_2.

Table 3.1-6 shows the available data on maximum 1-hour, 3-hour, 24-hour, and annual average SO_2 levels recorded at the Riverside-Rubidoux station during the period from 2009 to 2014. As indicated by this table, the maximum measured 1-hour average SO_2 levels comply with the NAAQS (75 ppb) and CAAQS (0.25 ppm); the maximum 3-hour average SO_2 levels comply with the NAAQS (0.5 ppm); and the maximum 24-hour values comply with the NAAQS and CAAQS of 0.14 ppm and 0.04 ppm, respectively. The table also demonstrates compliance with the annual SO_2 NAAQS of 0.03 ppm. Note that the 24-hour and annual NAAQS for SO_2 have been superseded by the 1-hour NAAQS, which became effective on August 23, 2010.

Table 3.1-6. Sulfur Dioxide Levels at Rubidoux (ppm)

Rubidoux Station, Riverside County	2009	2010	2011	2012	2013	2014
Highest 1-hour average	0.011	0.018	0.008	0.004	0.009	0.006
99th percentile 1-hour average	0.006	0.010	0.004	0.002	0.005	0.004
Highest 3-hour average	--	--	0.003	0.002	0.009	0.003
Highest 24-hour average	0.003	0.005	0.001	0.001	0.001	0.001
Annual Average	0.001	0.001	0.000	-- (b)	-- (b)	-- (b)
Days Over 1-hour State Standard (0.25 ppm)	0	0	0	0	0	0
Days Over 1-hour Federal Standard (75 ppb)[a]	0	0	0	0	0	0
Days Over 24-hour State Standard (0.04 ppm)	0	0	0	0	0	0
Days Over 3-hour Federal Standard (0.5 ppm)	0	0	0	0	0	0

Sources: ARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/air/data/index.html)

[a] To attain this standard, the 3-year average of the 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb.

[b] There were insufficient (or no) data available to determine the value.

NA = not applicable

3.1.2.4 Carbon Monoxide

Carbon monoxide is a product of incomplete combustion and is emitted principally from automobiles and other mobile sources of pollution. It is also a product of combustion from stationary sources (both industrial and residential) burning fuels. Peak CO levels occur typically during winter months as a result of a combination of higher emission rates and stagnant weather conditions.

Table 3.1-7 shows the available data on maximum 1-hour and 8-hour average CO levels recorded at the Palm Springs Fire Station monitoring station during the period from 2009 to 2014. As indicated by this table, the maximum measured 1-hour average CO levels comply with the NAAQS and CAAQS (35.0 ppm and 20.0 ppm, respectively) and the maximum 8-hour values comply with the NAAQS and CAAQS of 9.0 ppm. The highest individual 1-hour and 8-hour CO concentrations at this station during the period from 2009 to 2014 were 3.2 ppm and 1.5 ppm, respectively, both recorded in 2013. The project location within the Mojave Desert air basin is an unclassified area with respect to the state CO ambient standard, and the entire Mojave Desert air basin is an unclassified/attainment area with regards to the federal CO standards.

Table 3.1-7. Carbon Monoxide Levels at Palm Springs (ppm)

Palm Springs Fire Station Monitoring Station, Riverside County	2009	2010	2011	2012	2013	2014
Maximum 1-hour Average[a]	2.3	1.6	3.0	0.9	3.2	2.2
Maximum 8-hour Average	0.67	0.56	0.64	0.45	1.5	0.9
Days Over the 8-hour California Standard (9 ppm)	0	0	0	0	0	0
Days Over the 8-hour Federal Standard (9 ppm)	0	0	0	0	0	0

Sources: ARB ADAM Website (www.arb.ca.gov/adam/welcome.html); EPA AirData Website (http://www.epa.gov/airdata/)

[a] Max 1-hour Averages and 2013/2014 Max 8-hour Average obtained from http://www.epa.gov/airdata/, “Monitor Values” function. 2009-2012 8-hour Averages obtained from “Highest 4 Daily Maximum 8-Hour Carbon Monoxide Averages” on ARB ADAM Website. (www.arb.ca.gov/adam/welcome.html)

3.1.2.5 Respirable Particulate Matter (PM_{10})

Particulates in the air are caused by a combination of wind-blown fugitive dust; particles emitted from combustion sources and manufacturing processes; sea salts; and organic, sulfate, and nitrate aerosols formed in the air from emitted hydrocarbons, sulfur oxides, and NOx, respectively. In 1984, ARB adopted standards for PM_{10} and phased out the total suspended particulate (TSP) standards that had been in effect previously. PM_{10} standards were substituted for TSP standards because PM_{10} corresponds to the size range of particulates that can be inhaled into the lungs (respired), and therefore is a better measure to use in assessing potential health effects. In 1987, USEPA also replaced national TSP standards with PM_{10} standards.

Table 3.1-8 shows the maximum PM_{10} levels recorded at the Palm Springs Fire Station monitoring station during the period from 2009 through 2014 and the arithmetic annual average concentrations for the same period. (The arithmetic annual average is simply the arithmetic mean of the daily observations.) PM_{10} is monitored according to different protocols for evaluating compliance with the state and federal standards for this pollutant. Specifically, California uses a gravimetric or beta attenuation method, whereas compliance with federal standards is evaluated based on an inertial separation and gravimetric analysis. This accounts for the differing 24-hour concentrations listed in Table 3.1-8 that represent data obtained by means of the state and federal samplers.

Table 3.1-8. Particulate Matter (PM_{10}) Levels at Palm Springs ($\mu g/m^3$)

Palm Springs Fire Station Monitoring Station, Riverside County	2009	2010	2011	2012	2013	2014
Maximum 24-hour Average (federal monitors) [a]	116	144	85	117	111	114
Maximum 24-hour Average (state monitors)	133.0	37.0	41.0	37.0	127.0	56.0
California Annual Average[b]	--	18.3	18.1	16.1	22.1	--
Estimated Number of Days Exceeding Federal Standard (150 $\mu g/m^3$)	-- [c]	0	2	0	1	1.1
Estimated Number of Days Exceeding State Standard (50 $\mu g/m^3$)	-- [c]	0	0	0	13.1	--

Source: Federal data from http://www.epa.gov/airdata/; state data from ARB ADAM Website (www.arb.ca.gov/adam/welcome.html).

[a] Excludes exceptional events.

[b] On December 17, 2006, the annual PM_{10} federal standard (50 $\mu g/m^3$) was revoked.

[c] There were insufficient (or no) data available to determine the value.

$\mu g/m^3$ = micrograms per cubic meter

PM_{10} = particulate matter less than 10 microns in diameter

At the Palm Springs Fire Station monitoring station, the maximum 24-hour PM_{10} levels exceed the CAAQS state standard of 50 micrograms per cubic meter ($\mu g/m^3$) a number of times per year. The maximum daily concentration[9] recorded during the analysis period was 133 $\mu g/m^3$ (state samplers) in 2009. The maximum annual average concentration recorded at Palm Springs was 22.1 $\mu g/m^3$ in 2013, which is above the state standard of 20 $\mu g/m^3$. The federal annual PM_{10} standard was revoked by the EPA in 2006 because of a lack of evidence linking health problems to long-term exposure to coarse particle pollution. The attainment status of the project location within Riverside County is “unclassified” with respect to the federal PM_{10} standard, and nonattainment with respect to the state PM_{10} standards.

[9] Excluding approved exceptional events.

3.1.2.6 Fine Particulates ($PM_{2.5}$)

Fine particulates result from fuel combustion in motor vehicles and industrial processes, residential and agricultural burning, and atmospheric reactions involving NOx, SOx, and organics. Fine particulates are referred to as $PM_{2.5}$ and have a diameter equal to or less than 2.5 microns. In 1997, EPA established annual and 24-hour NAAQS for $PM_{2.5}$ for the first time. The most recent revision to the standard regulating the 3-year average of the 98th percentile of 24-hour $PM_{2.5}$ concentrations (35 $\mu g/m^3$) became effective on December 17, 2006. In December 2012, EPA lowered the annual primary $PM_{2.5}$ standard from 15.0 to 12.0 $\mu g/m^3$ and established a secondary fine particle standard of 15.0 $\mu g/m^3$. The $PM_{2.5}$ data in Table 3.1-9 show that the national 24-hour average NAAQS of 35 $\mu g/m^3$ was not exceeded from 2009 to 2014. The maximum recorded 24-hour average 98th percentile value was 15 $\mu g/m^3$ in 2009. The annual $PM_{2.5}$ data are also presented in this table. The maximum annual arithmetic mean was 6.6 $\mu g/m^3$, recorded in 2009, which is below the primary national and state standard of 12 $\mu g/m^3$. The project location within Riverside County is in attainment with regard to the federal $PM_{2.5}$ standards and is unclassified/attainment with regard to the state $PM_{2.5}$ standard.

Table 3.1-9. Particulate Matter ($PM_{2.5}$) Levels at Palm Springs ($\mu g/m^3$)

Palm Springs Fire Station Monitoring Station, Riverside County	2009	2010	2011	2012	2013	2014
Maximum 24-hr Average 98th Percentile[a]	14.6	12.6	12.5	13.7	13.8	13.2
Annual Average	6.6	5.9	6.0	6.4	6.5	--
Estimated Number of Days Exceeding Federal Standard (35 $\mu g/m^3$)	0	0	0	0	0	0

Sources: ARB ADAM Website (www.arb.ca.gov/adam/welcome.html).

[a] EPA lowered the 24-hour standard from 65 $\mu g/m^3$ to 35 $\mu g/m^3$ on December 17, 2006. Compliance with this standard is based on the 3-year average of the 98th percentile daily concentrations.

$\mu g/m^3$ = micrograms per cubic meter

$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

3.1.2.7 Airborne Lead (Pb)

Lead pollution has historically been emitted predominantly from the combustion of fuels; however, legislation in the early 1970s required a gradual reduction of the lead content of gasoline. Beginning with the introduction of unleaded gasoline in 1975, lead levels have been dramatically reduced throughout the U.S., including California, and violations of the ambient standards for this pollutant have been virtually eliminated.

On October 15, 2008, EPA revised the federal ambient air quality standard for lead, lowering it from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$ for both the primary and the secondary standard. EPA determined that numerous health studies are now available that demonstrate health effects at much lower levels of lead than previously thought. EPA subsequently published the final rule in the Federal Register on November 12, 2008. This is the first time that the federal lead standard has been revised since it was first issued in 1978.

In addition to revising the level of the standard, EPA changed the averaging time from a quarterly average to a rolling three-month average. The level of the standard is “not to be exceeded” and is evaluated over a three-year period. Lead levels are measured as lead in total suspended particulate (TSP). The revised lead standard also contains new monitoring requirements.

Ambient lead levels are monitored in San Bernardino. Table 3.1-10 lists the federal air quality standard for airborne lead and the levels reported in San Bernardino between 2009 and 2014. Maximum quarterly levels are not reported on EPA’s website; because the maximum 24-hour averages must be higher than the quarterly average, the data show that lead levels are actually well below the federal standard. The Mojave Desert air basin is in attainment with respect to the state ambient standard for lead; there is no area designation information for the federal standard.

Table 3.1-10. Airborne Lead (Pb) Levels at San Bernardino (µg/m^3)

San Bernardino Monitoring Station, San Bernardino County	2009	2010	2011	2012	2013	2014
Maximum 24-hour Average	0.020	0.020	0.012	0.016	0.018	0.02
Number of Days Exceeding Federal Standard (1.5 µg/m^3)	0	0	0	0	0	0

Sources: EPA AirData Website (http://www.epa.gov/airdata/)

µg/m^3 = micrograms per cubic meter

3.1.2.8 Particulate Sulfates

Sulfate compounds found in the lower atmosphere consist of both primary and secondary particles. Primary sulfate particles are directly emitted from open pit mines, dry lakebeds, and desert soils. Fuel combustion is another source of sulfates, both primary and secondary. Secondary sulfate particles are produced when oxides of sulfur (SOx) emissions are transformed into particles through physical and chemical processes in the atmosphere. Particles can be transported long distances. The Mojave Desert air basin is in attainment with respect to the state ambient standard for sulfates; there is no federal standard.

3.1.2.9 Other State-Designated Criteria Pollutants

Along with sulfates, California has designated hydrogen sulfide and visibility-reducing particles as criteria pollutants, in addition to the federal criteria pollutants. The Mojave Desert air basin remains unclassified for both pollutants.

3.1.2.10 Existing Air Quality

As outlined in 40 CFR 51, Appendix W, Section 9.2, the background data used to evaluate the potential air quality impacts need not be collected on a project site, as long as the data are representative of the air quality in the subject area. The following three criteria were used for determining whether the background ambient air quality data are representative: (1) location, (2) data quality, and (3) data currentness. These criteria are defined and applied to the project as follows:

- **Location:** The measured data must be representative of the areas where the maximum concentration occurs for the proposed stationary source, existing sources, and a combination of the proposed and existing sources.

  The nearest monitoring station to the project site is Blythe station. This site is located approximately 5 miles from the project site. However, only ozone is monitored at this site.

  Because the Blythe monitoring station does not collect data on NO_2, SO_2, CO, PM_{10} and $PM_{2.5}$ ambient concentrations, other monitoring sites with similar site characteristics were used to provide representative background concentrations for these pollutants. The Palm Springs monitoring station (PM_{10}, $PM_{2.5}$, NO_2, and CO) is located approximately 110 miles west of the project site. The Rubidoux monitoring station (SO_2) is located approximately 170 miles west northwest of the project site. In general, the Palm Springs and Rubidoux monitoring stations are considered to provide conservative estimates of the worst-case background concentrations because of their proximity to the South Coast Air Basin (Metropolitan Los Angeles). Monitoring stations located in Imperial County were not considered to be representative of conditions at the project site because of the predominant air flow patterns and air pollution from Mexico that creates a significant local influence for the worst-case pollutant concentration readings at some locations in Imperial County.

- **Data quality:** Data must be collected and equipment must be operated in accordance with the requirements of 40 CFR Part 58, Appendices A and B, and PSD monitoring guidance.

  The ARB and EPA ambient air quality data summaries were used as the primary sources of data. Therefore, the data at the monitoring stations listed in Table 3.1-11 meet the data quality requirements of 40 CFR Part 58, Appendices A and B, and PSD monitoring guidance.

- **Data currentness:** The data are current if they have been collected within the preceding 3 years and are representative of existing conditions.

  The maximum ambient background concentrations from the period 2012 through 2014 were combined with the modeled concentrations and used for comparison to the ambient air quality standards. Therefore, the data presented above represent the 3 most recent years of data available.

Based on the criteria presented above, the three most recent years of background NO_2, CO, PM_{10} and $PM_{2.5}$ data from the Palm Springs monitoring station and the three most recent years of background SO_2 from the Rubidoux monitoring station have been used to represent existing background concentrations in the project area. As discussed further below, the existing BEP generating units are shown as background sources in the air quality impact assessment.

A summary of the monitored background concentrations for 2012 through 2014 are presented in Table 3.1-11.

Table 3.1-11. Background Air Concentrations (2012–2014)[a]

Pollutant	Averaging Time	Existing Monitored Concentrations, µg/m³			Maximum for the Period, µg/m³
		2012	2013	2014	
NO_2 [b]	1-hour (max)	84.6	97.8	86.5	97.8
	1-hour (98th percentile)	73.9	72.9	77.1	77.1
	Annual[d]	13.2	13.2	13.2	13.2
SO_2 [c]	1-hour (max)	10.4	22.9	15.6	22.9
	1-hour (99th percentile)	5.2	13.0	10.4	13.0
	3-hour[e]	5.2	22.6	7.8	22.6
	24-hour	2.6	2.6	2.6	2.6
CO [b]	1-hour	1,125	4,000	2,750	4,000
	8-hour	500	1,667	1,698	1,698
PM_{10} [b]	24-hour	37.0	127.0	56	127.0
	Annual	16.1	22.1	n/a	22.1
$PM_{2.5}$ [b]	24-hour (98th percentile)	13.7	13.8	13.2	13.8
	Annual	6.5	6.5	n/a	6.5

[a] The ARB and EPA ambient air quality data summaries were used as reference.
[b] Data from the Palm Springs monitoring station
[c] Data from the Rubidoux monitoring station
[d] Annual Arithmetic Mean
[e] Federal secondary standard

n/a: data not available

3.1.2.11 Existing Emissions

The 76-acre SEP site is currently vacant, and consists of open desert lands. Other than naturally occurring emissions, including fugitive dust, there are no emitting activities on the project site. The permitted BEP II facility has not been constructed.

The adjacent BEP project is owned and operated by Blythe Energy Inc., a wholly owned subsidiary of APHUS. SEP is owned by AltaGas Sonoran Energy Inc., which is also a wholly owned subsidiary of APHUS. Because the two projects are contiguous and have common ownership and control, they are treated as a single facility under local, state, and federal air permitting regulations. The facilities have been licensed separately by the CEC and will continue to be operated by separate subsidiaries, so for purposes of the CEC license the proposed amendment will affect only SEP.[10] However, for CEQA purposes and at the request of the District, BEP has been shown as a background emissions source in the ambient air quality impact assessments prepared for the proposed project.

The existing BEP includes two Siemens V84 combined cycle gas turbines, a mechanical-draft wet cooling tower, a chiller cooling tower, a diesel-powered fire water pump, and ancillary facilities. Some existing facilities will be shared between the two plants, as follows:

- Well water supply
- Control room (and staff)
- Wastewater disposal
- Stormwater management
- Gas line

The existing BEP currently operates on an as-needed basis, with an annual capacity factor of about 40 percent. Table 3.1-12 summarizes the allowable emissions (potential to emit) for the existing BEP and the average actual emissions for the most recent 3-year period. The potential to emit for the existing BEP is shown in more detail in Appendix 3.1B, Table 3.1B-11.

Table 3.1-12. Existing BEP: PTE and Actual Emissions, tons per year

	NOx	SO_2	CO	VOC	$PM_{10}/PM_{2.5}$[a]
Allowable Emissions (Potential to Emit)	97	24	97	24	56.9
Reported Emissions, 2012	60.6	1.2	40.2	1.4	45.9
Reported Emissions, 2013	61.8	1.2	44.3	1.4	46.2
Reported Emissions, 2014	57.5	1.1	28.8	1.3	42.2

[a] PM PTE shown reflects new PM limit that is being proposed concurrently with the SEP project modifications. The reported emissions are based on an emission factor of 10 lb/hr per unit; the new limit will be 6.2 lb/hr per unit so historical emissions calculated on a basis consistent with the proposed PTE will be about 60% of the values shown. All reported emissions and emission limits contain emissions from the cooling towers.

3.1.3 Laws, Ordinances, Regulations, and Standards

3.1.3.1 Federal LORS

The US EPA has responsibility for enforcing, on a national basis, the requirements of many of the country's environmental and hazardous waste laws. California is under the jurisdiction of EPA Region 9, which has its offices in San Francisco. Region 9 is responsible for the local administration of EPA programs for California, Arizona, Nevada, Hawaii, and certain Pacific trust territories. EPA's activities relative to the California air pollution control program focus principally on reviewing California's submittals for the State Implementation Plan (SIP). The SIP is required by the federal Clean Air Act to

[10] As discussed earlier, BEP's project owner is applying for contemporaneous emissions reductions as part of the District application for the modification to SEP; however, the PM_{10} and SO_2 reductions at BEP are being handled separately by the CEC, as an amendment to the BEP license.

demonstrate how all areas of the state will meet the national ambient air quality standards by the federally specified deadlines (42 USC §7409, 7411).

The federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as SEP. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the federal Clean Air Act:

- Prevention of Significant Deterioration (PSD)
- Nonattainment New Source Review (NANSR)
- Title IV: Acid Rain Program
- Title V: Operating Permits
- National Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAPs)

Prevention of Significant Deterioration Program.

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Requirements: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). For the MDAQMD, the PSD pollutants are ozone (for which VOC is a surrogate), SOx, NOx, CO, PM_{10}, $PM_{2.5}$, and greenhouse gases (GHGs). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks and wilderness areas).

The PSD requirements apply to any project that is a new major stationary source or a major modification to an existing major stationary source. A major source is a listed facility (one of 28 PSD source categories listed in the federal Clean Air Act) that emits at least 100 tons per year (tpy), or any other facility that emits at least 250 tpy.[11]

A major modification is any project at a major stationary source that results in a significant increase in emissions of any PSD pollutant.

A significant increase for a PSD pollutant is an increase above the significant emission rate for that pollutant (Table 3.1-13). It is important to note that, once PSD is triggered by any pollutant, PSD requirements apply to any PSD pollutant with an emission increase above the significance level, regardless of whether the facility is major for that pollutant.

Table 3.1-13. PSD Significant Emission Thresholds

Pollutant	PSD Significant Emission Threshold (tpy)[a]
SO_2	40
PM_{10}	15
$PM_{2.5}$	10

[11] Effective July 1, 2011, under EPA's Tailoring Rule [75 FR 31514, June 3, 2010] a stationary source that emits more than 100,000 tpy of GHGs was also considered to be a major stationary source. However, as a result of a 2014 Supreme Court decision (Utility Air Regulatory Group v. EPA (No. 12-1146)), EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD permit. The Court also said that PSD permits that are otherwise required (based on emissions of other pollutants) may continue to require limitations on GHG emissions based on the application of Best Available Control Technology (BACT). EPA will amend the GHG portion of the PSD regulations to conform to the Supreme Court decision once the lower courts have acted.

Table 3.1-13. PSD Significant Emission Thresholds

Pollutant	PSD Significant Emission Threshold (tpy)[a]
NOx	40
CO	100
Lead	0.6
GHGs	75,000[b]

[a] 40 CFR 52.21 (b)(1)(23).

[b] Based on the Supreme Court's June 23, 2014, opinion on the GHG Tailoring Rule (Utility Air Regulatory Group v. EPA, No. 12-1146), the project will not be subject to PSD review based solely on its GHG emissions. However, the June 16, 2011, version of 40 CFR 52.21 includes the 75,000 tpy CO2e threshold, so that threshold is shown here for completeness.

The principal requirements for the PSD program encompass the following:

- Emissions of pollutants that are subject to PSD review must be controlled using BACT.
- Air quality impacts of the project, in combination with other increment-consuming sources, must not exceed maximum allowable incremental increases.
- Air quality impacts of all sources in the area plus ambient pollutant background levels cannot exceed NAAQS.
- Preconstruction and/or post-construction air quality monitoring may be required.
- The air quality impacts on soils, vegetation, and nearby PSD Class I areas (specific national parks and wilderness areas) must be evaluated.

Best Available Control Technology. BACT must be applied to any new or modified major source to minimize the emissions increase of those pollutants exceeding the PSD emission thresholds. EPA defines BACT as an emissions limitation based on the maximum degree of reduction for each subject pollutant, considering energy, environmental, and economic impacts, that is achievable through the application of available methods, systems, and techniques. BACT must be as stringent as any emission limit required by an applicable NSPS or NESHAP.

Air Quality Impact Analysis. An air quality dispersion analysis must be conducted to evaluate impacts of significant emission increases from new or modified facilities on ambient air quality. PSD source emissions must not cause or contribute to an exceedance of any ambient air quality standard, and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 3.1-14. Once PSD review is triggered for the project, all pollutants with emission increases above the PSD significance thresholds are subject to this requirement.

Table 3.1-14. PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	SILs ($\mu g/m^3$)[a]	Maximum Allowable Class II Increments[b]
SO_2	Annual	1.0	20
	24-hr	5	91
	3-hr	25	512
	1-hr	7.8[c]	No 1-hr increment

Table 3.1-14. PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	SILs (µg/m³)[a]	Maximum Allowable Class II Increments[b]
PM_{10}	Annual 24-hr	1.0 5	17 30
$PM_{2.5}$[d]	Annual 24-hr	0.3 1.2	4 9
NO_2	Annual 1-hr	1.0 7.5[c]	25 No 1-hr increment
CO	8-hr 1-hr	500 2,000	No CO increments

[a] 40 CFR 51.165 (b)(2).

[b] 40 CFR 52.21 (c)

[c] EPA has not yet defined significance impact levels (SILs) for one-hour NO_2 or SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, values of 4 ppb (7.5 µg/m³) for NO_2 and 3 ppb (7.8 µg/m³) for SO_2 may be used. These values will be used in this analysis wherever a SIL will be used for NO_2 or SO_2.

[d] In January 2013, EPA sought and the U.S. Court of Appeals for the District of Columbia Circuit granted remand and vacatur of these SILs as they apply for purposes of avoiding a cumulative impacts analysis under federal PSD requirements (40 CFR § 51.166(k)(2) and § 52.21(k)(2)). However, EPA has retained these SILs for purposes of demonstrating whether a source locating in an attainment/unclassifiable area will be deemed to cause or contribute to a violation in a downwind nonattainment area. See Sierra Club v. EPA, No. 10-1413 (D.C. Cir. 2013), slip op. 9. Accordingly, application of these SILs for purposes of satisfying the District's requirement to assure that a new or modified facility does not interfere with the attainment or maintenance of an ambient air quality standard (MDAQMD Rule 1300, §A.1.b) may be appropriate.

Air Quality Monitoring. At its discretion, the PSD permit issuer may require preconstruction and/or post-construction ambient air quality monitoring for PSD sources if representative monitoring data are not already available. Preconstruction monitoring data must be gathered over a one-year period to characterize local ambient air quality. Post-construction air quality monitoring data must be collected as deemed necessary by the PSD permit issuer to characterize the impacts of proposed project emissions on ambient air quality.

Protection of Class I Areas. The potential increase in ambient air quality concentrations for attainment pollutants (i.e., NO_2, PM_{10}, or SO_2) within Class I areas closer than approximately 100 km may need to be quantified if the new or modified PSD source were to have a sufficiently large emission increase as evaluated by the Class I area Federal Land Managers. In such a case, a Class I visibility impact analysis will also be performed.

Growth, Visibility, Soils, and Vegetation Impacts. Impairment to visibility, soils, and vegetation resulting from PSD source emissions as well as associated commercial, residential, industrial, and other growth must be analyzed. This analysis shows cumulative impacts to local ambient air quality.

Because the Mojave Desert AQMD PSD program has not received EPA approval, facilities subject to PSD requirements in this district are required to obtain PSD approvals to construct from EPA Region 9. As discussed in more detail below, the proposed project will not be subject to PSD review.

Administering Agency: EPA Region 9.
Nonattainment New Source Review.

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Requirement: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment and maintenance of NAAQS. Nonattainment new source review jurisdiction has been delegated to the MDAQMD for all nonattainment pollutants and is discussed further under local LORS and conformance below.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Acid Rain Program.

Authority: Clean Air Act §401 (Title IV), 42 USC §7651

Requirement: Requires the monitoring and reporting of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to monitor, record, and in some cases limit SO_2 and NOx emissions from electrical power generating facilities. These standards are implemented at the local level with federal oversight.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Title V Operating Permits Program.

Authority: Clean Air Act §501 (Title V), 42 USC §7661

Requirements: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, Phase II acid rain facilities, subject solid waste incinerator facilities, and any facility listed by EPA as requiring a Title V permit. MDAQMD has received delegation authority for this program.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

National Standards of Performance for New Stationary Sources.

Authority: Clean Air Act §111, 42 USC §7411; 40 CFR Part 60

Requirements: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established NAAQS) from new or modified facilities in specific source categories. These standards are implemented at the local level with federal oversight. The applicability of these regulations depends on the equipment size, process rate, and/or the date of construction, modification, or reconstruction of the affected facility.

Several NSPS will be applicable to the proposed project. The gas turbines will be subject to the requirements of Subpart KKKK, Standards of Performance for Stationary Gas Turbines, which sets limits on NOx and SO_2 emissions from gas turbines. Subpart KKKK limits NOx and SO_2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 850 MMBtu/hr are 15 ppmv @ 15% O_2/0.43 lb per MW-hr for NOx, and 0.90 lb per MW-hr SO_2 for SOx.

The auxiliary boiler will be subject to the requirements of Subpart Dc, Standards of Performance for Industrial, Commercial and Institutional Boilers. Because the boiler will be fired solely on natural gas, the only applicable requirements relate to initial notification and recordkeeping.

NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, will apply to the new fire pump engine. For the size of engine proposed, the NSPS requires the purchase of engines meeting the EPA engine nonroad certification level of Tier 3 or better depending on the year the engine is manufactured/purchased. This regulation also requires the engine to use ultra-low sulfur content diesel fuel.

On Sept. 20, 2013, the EPA issued a revised proposed NSPS to control GHG emissions from new power plants. The EPA proposed separate standards for natural gas-fired turbines and coal-fired units. The proposed GHG emission limits (40 CFR Part 60 Subpart TTTT) for new natural gas-fired combustion turbines subject to the regulation are 1,000 lb CO_2/MWh (new combustion turbines with a heat input rating greater than 850 MMBtu/hr) and 1,100 lb CO_2/MWh (new combustion turbines with a heat input rating equal to or less than 850 MMBtu/hr). New combustion turbines that supply less than one-third of their potential electric output (on a three-year rolling average basis) to a utility distribution system are exempt from this regulation. Because the new gas turbine associated with the proposed project will supply more than one-third of its potential electric output to the local utility, the unit may be subject to this regulation if it is adopted.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

National Emission Standards for Hazardous Air Pollutants.
Authority: Clean Air Act §112, 42 USC §7412

Requirements: Establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution, but for which NAAQS have not been established) from major sources of HAPs in specific source categories.[12] These standards are implemented at the local level with federal oversight. Only the NESHAPs for gas turbines, which limit formaldehyde emissions from gas turbines, is potentially applicable to the new power plant project.[13] As discussed further below, the gas turbine NESHAP may be applicable to the proposed project because the addition of SEP to BEP will make the combined stationary source a major source of HAPs. However, in 2004, EPA stayed the effectiveness of the NESHAP for new lean premix and diffusion flame gas-fired gas turbines. Therefore, the NESHAP does not apply to the proposed project.

Administering Agency: MDAQMD, with EPA Region 9 oversight.

Compliance Assurance Monitoring (CAM).
Authority: 40 CFR 64 Compliance Assurance Monitoring (CAM)

Requirements: Requires compliance monitoring at emission units at major stationary sources that are required to obtain a Title V permit, and that use control equipment to achieve a specified emission limit. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. CAM is usually implemented through the Title V permit. The only equipment associated with the proposed project that may be affected by CAM is the oxidation catalyst that will be installed on the new gas turbine (if VOC control is claimed for use of oxidation catalysts).

Administering Agency: MDAQMD, with EPA Region 9 oversight.

3.1.3.2 State LORS

ARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. ARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the CAAQS; to review the operation of the local air pollution control districts (APCDs); and to review and coordinate preparation of the SIP for achievement of the NAAQS. ARB has implemented the following state or federal stationary source regulatory programs in accordance with the requirements of the federal Clean Air Act and California Health & Safety Code (H&SC):

- State Implementation Plan
- California Clean Air Act
- Toxic Air Contaminant Program
- Airborne Toxic Control Measure for Stationary Compression-Ignition Engines

[12] A major source of HAPs is one that emits more than 10 tons per year (tpy) of any individual HAP, or more than 25 tpy of all HAPs combined.

[13] The auxiliary boiler is not subject to the major source boiler NESHAP (40 CFR 63 Subpart DDDDDD) because it is fueled solely on natural gas. The emergency fire pump engine compiles with the applicable NESHAP (40 CFR 63 Subpart ZZZZ) by complying with 40 CFR 60 Subpart IIII.

- Nuisance Regulation
- Air Toxics "Hot Spots" Act
- CEC and ARB Memorandum of Understanding

State Implementation Plan (SIP).

Authority: Health & Safety Code (H&SC) §39500 et seq.

Requirements: The SIP demonstrates the means by which all areas of the state will attain and maintain NAAQS within the federally mandated deadlines, as required by the federal Clean Air Act. ARB reviews and coordinates preparation of the SIP. Local districts must adopt new rules or revise existing rules to demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in attainment of the NAAQS. The relevant MDAQMD Rules and Regulations that have been incorporated into the SIP are discussed with the local LORS in Section 3.1.3.3.

Administering Agency: MDAQMD, with ARB and EPA Region 9 oversight.

California Clean Air Act.

Authority: H&SC §40910 – 40930

Requirements: Established in 1989, the California Clean Air Act requires local districts to attain and maintain both national and state ambient air quality standards at the "earliest practicable date." Local districts must prepare air quality plans demonstrating the means by which the ambient air quality standards will be attained and maintained. The relevant components of the MDAQMD Air Quality Plan are discussed with the local LORS.

Administering Agency: MDAQMD, with ARB oversight.

Toxic Air Contaminant Program.

Authority: H&SC §39650 – 39675

Requirements: Adopted in 1983, the Toxic Air Contaminant Identification and Control Act created a two-step process to identify TACs and control their emissions. ARB identifies and prioritizes the pollutants to be considered for identification as TACs. ARB assesses the potential for human exposure to a substance, while the Office of Environmental Health Hazard Assessment evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report, which concludes whether a substance poses a significant health risk and should be identified as a TAC. In 1993, the Legislature amended the program to encompass the 187[14] federally identified hazardous air pollutants as TAC. ARB reviews the emission sources of an identified toxic air contaminant and, if necessary, develops air toxics control measures to reduce the emissions.

Administering Agency: ARB

Airborne Toxic Control Measure for Stationary Compression-Ignition Engines.

Authority: Title 17, California Code of Regulations, §93115

Requirements: The purpose of the airborne toxic control measure (ATCM) is to reduce diesel particulate matter (DPM) and criteria pollutant emissions from stationary diesel-fueled compression ignition engines. The ATCM applies to stationary compression-ignition engines with a rating greater than 50 brake horsepower. The ATCM requires the use of ARB-certified diesel fuel or equivalent, and limits emissions from, and operations of, compression ignition engines.

Administering Agency: MDAQMD and ARB

[14] Methyl ethyl ketone was removed from the list on December 19, 2005 (http://www.epa.gov/ttn/atw/pollutants/atwsmod.html, accessed April 9, 2006).

Nuisance Regulation.

Authority: CA Health & Safety Code §41700

Requirements: Provides that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause injury or damage to business or property."

Administering Agency: MDAQMD and ARB

Air Toxic "Hot Spots" Act.

Authority: H& SC §44300-44384; 17 CCR §93300-93347

Requirements: Adopted in 1987, the Air Toxics "Hot Spots" Information and Assessment Act supplements the TAC program, by requiring the development of a statewide inventory of air toxics emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant air toxics and sources of air toxics emissions; (2) an emissions inventory report quantifying air toxics emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose air toxics emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose air toxics emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: MDAQMD and ARB

CEC and ARB Memorandum of Understanding.

Authority: CA Pub. Res. Code §25523(a); 20 CCR §1752, 1752.5, 2300-2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

Requirements: Provides for the inclusion of requirements in the CEC's decision on an AFC to assure protection of environmental quality; the application is required to contain information concerning air quality protection.

Administering Agency: CEC

California Climate Change Regulatory Program.

Authority: Stats. 2006, Ch. 488 and CA Health & Safety Code § 38500-38599

Requirements: The State of California adopted the Global Warming Solutions Act of 2006 (Assembly Bill [AB] 32) on September 27, 2006, which requires sources within the state to reduce carbon emissions to 1990 levels by the year 2020. Based on this statutory authority, ARB has adopted regulations to limit GHG emissions from electric power plants and other specific source categories through a cap-and-trade program. In addition, ARB has adopted regulations requiring the calculation and reporting of GHG emissions from subject facilities. Pursuant to a 2005 Executive Order, additional reductions are required by 2050. In April 2015, Governor Brown issued an Executive Order establishing a new interim statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure that the state meets the 2050 goal.

AB 32 does not directly amend other environmental laws, such as the California Environmental Quality Act (CEQA). Instead, it provides for creation of a GHG emissions program that will involve identification of sources, prioritization of sources for regulation based on significance of source contribution to GHG emissions, and eventual regulation of those sources.

Greenhouse gases contain the pollutants described below.

- Carbon dioxide (CO_2) is a naturally occurring gas, as well as a by-product of burning fossil fuels and biomass, land-use changes, and other industrial processes. It is the principal anthropogenic greenhouse gas that affects the Earth's radiative balance.
- Methane (CH_4) is a greenhouse gas with a global warming potential (GWP) most recently estimated at 25 times that of CO2. GWP is a measure of how much a given mass of greenhouse gas is estimated to contribute to global warming and is a relative scale that compares the mass of one greenhouse gas to that same mass of carbon dioxide. CH4 is produced through anaerobic (without O_2) decomposition of waste in landfills, animal digestion, decomposition of animal wastes, production and distribution of natural gas and petroleum, coal production, and incomplete fossil fuel combustion.
- Nitrous oxide (N_2O) is a greenhouse gas with a GWP of 298 times that of CO2. Major sources of nitrous oxide are soil cultivation practices, especially the use of commercial and organic fertilizers, fossil fuel combustion, nitric acid production, and biomass burning.
- Sulfur hexafluoride (SF_6) is a colorless gas soluble in alcohol and ether, and slightly soluble in water. It is a very powerful greenhouse gas used primarily in electrical transmission and distribution systems, as well as dielectrics in electronics.

The annual GHG emission reports to ARB for subject facilities must show the project's emission rates of greenhouse gases from the stack, cooling towers, fuels and materials handling processes, delivery and storage systems, as well as from all on-site secondary emission sources. The facility will also be required to participate in the cap and trade program.

On January 25, 2007, the PUC and CEC jointly adopted a Greenhouse Gas Emissions Performance Standard (EPS) in an effort to help mitigate climate change. The EPS is a facility-based emissions standard requiring that all new long-term commitments for baseload generation to serve California consumers be with power plants that have emissions no greater than a combined-cycle gas turbine plant. That level is established at 1,100 pounds of CO_2 per MW-hour (or 0.50 MT CO_2 per MW-hour).

Administering Agencies: ARB and CEC.

3.1.3.3 Local LORS

When the state's air pollution statutes were reorganized in the mid-1960s, local districts were required to be established in each county of the state. There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs, such as the MDAQMD), with more comprehensive authority over nonvehicular sources, as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California. Local districts have principal responsibility for the following:

- Developing plans for meeting the NAAQS and CAAQS
- Developing control measures for nonvehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards
- Implementing permit programs established for the construction, modification, and operation of sources of air pollution
- Enforcing air pollution statutes and regulations governing nonvehicular sources
- Developing programs to reduce emissions from indirect sources

Mojave Desert Air Quality Plans.

Authority: H&SC §40914

Requirements: Air quality plans define the proposed strategies, including stationary source and transportation control measures and new source review rules that will be implemented to attain and maintain the state ambient air quality standards. The relevant stationary source control measures and new source review requirements are discussed with MDAQMD Rules and Regulations.

Administering Agency: MDAQMD with EPA Region 9 and ARB oversight.

Mojave Desert Air Quality Management District Rules and Regulations.

Authority: H&SC §4000 et seq., H&SC §40200 et seq., indicated MDAQMD Rules

Requirements: Establishes procedures and standards for issuing permits; establishes standards and limitations on a source-specific basis.

Administering Agency: MDAQMD with EPA Region 9 and ARB oversight.

Authority to Construct.

Regulation II—Permits, Rule 201 (Permit to Construct) specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain an Authority to Construct from the MDAQMD. Under Regulation XIII Rule 1306 (Electric Energy Generating Facilities) Section (E)(3)(b), the District's Final Determination of Compliance acts as an authority to construct for a power plant upon approval of the project by the CEC.

Review of New or Modified Sources.

Regulation XIII (New Source Review) implements the federal NSR and PSD programs, as well as the New Source Review requirements of the California Clean Air Act. The rule contains the following elements:

- BACT and Lowest Achievable Emission Rates (LAER)
- Emission offsets
- Air quality impact analysis (AQIA)

Best Available Control Technology.

BACT must be applied to any new or modified permit unit that has a potential to emit 25 pounds per day or more of any Nonattainment Air Pollutant. The Nonattainment Air Pollutants are ozone and its precursors NOx and volatile organic compounds (VOC), and PM_{10} and its precursors NOx, SOx, and VOC.

The MDAQMD defines BACT (Rule 1301(K)(2)) for a nonmajor facility as the most stringent emission limitation or control technique that meets one of the following criteria:

- Has been achieved in practice for the category or class of source
- Is any emission limitation or control technique determined to be technologically feasible and cost-effective
- Is contained in any SIP approved by EPA for such emission unit category, unless demonstrated to not be proven in field application, not be technologically feasible, or not be cost-effective

Emission Offsets.

A new or modified facility resulting in facility-wide emission increases above the thresholds shown in Table 3.1-15 must offset emission increases of nonattainment pollutants (and their precursors).

Table 3.1-15. MDAQMD Offset Emission Thresholds

Pollutant	Offset Threshold, tpy
CO	100[a]

Table 3.1-15. MDAQMD Offset Emission Thresholds

Pollutant	Offset Threshold, tpy
Hydrogen Sulfide	10
Lead	0.6
PM_{10}	15
NOx	25
SOx	25
VOC	25

[a] The project is located in a CO attainment area; therefore offsets are not required for CO.

Source: MDAQMD Regulation XIII, Rule 1303 (B)(1)

Toxic Risk Management. Regulation XIII, Rule 1320 (New Source Review for Toxic Air Contaminants) provides a mechanism for evaluating the potential impact of air emissions of TAC (also called noncriteria pollutants) from new, modified, and relocated facilities or permit units in the MDAQMD. The rule imposes more stringent requirements on permit units with higher risks, as shown in Table 3.1-16.

Table 3.1-16. MDAQMD Health Risk Thresholds

Requirement	Risk Threshold	Hazard Index
Utilize TBACT	1 × 10-6 (residential receptor) 1 × 10-5 (point of maximum impact)	--
Public Notification	10 × 10-5	1
Application Denial	100 × 10-5	10

CEC Review. Regulation XIII, Rule 1306 establishes a procedure for coordinating MDAQMD review of power plant projects with the CEC's AFC and Small Power Plant Exemption (SPPE) processes. Under this rule, the MDAQMD reviews the AFC/SPPE and issues a Determination of Compliance for a proposed project. Upon approval of the project by the CEC, this Determination of Compliance is equivalent to an Authority to Construct. A Permit to Operate is issued following demonstration of compliance with all permit conditions.

Prevention of Significant Deterioration. In the MDAQMD the Federal PSD program is administered by EPA, Region IX.

Acid Rain Permit. Regulation XII Rule 1210 (Acid Rain Provisions of Federal Operating Permits) adopts, by reference, the federal requirements of 40 CFR Part 72, which requires that certain subject facilities comply with maximum operating emissions levels for SO_2 and NOx, and monitor SO_2, NOx, and carbon dioxide emissions and exhaust gas flow rates. A Phase II Acid Rain facility, such as a new power plant project, must obtain an Acid Rain permit. A permit application must be submitted to the MDAQMD at least 24 months before operation of the new unit commences. The application must present all relevant Phase II sources at the facility, a compliance plan for each unit, applicable standards, and an estimated commencement date of operations.

Federal Operating Permit. Regulation XII (Federal Operating Permits) requires new or modified major facilities, NSPS sources, NESHAP sources, and/or Phase II Acid Rain facilities to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the 1990 Clean Air Act

Amendments. A Title V permit application for a modified source must be submitted to the MDAQMD prior to commencing operation. The application must present a process description, all new stationary sources at the facility, applicable regulations, estimated emissions, associated operating conditions, alternative operating scenarios, a facility compliance plan, and a compliance certification.

New Source Performance Standards. Regulation IX Rule 900 (Standards of Performance for New Stationary Sources) adopts, by reference, the federal standards of performance for new or modified stationary sources. The applicability and requirements of the NSPS for stationary gas turbine, auxiliary boiler, and internal combustion engine are discussed above under the federal regulations section.

MDAQMD Prohibitory Rules. The general prohibitory rules in Regulation IV applicable to the project are summarized below.

Rule 401– Visible Emissions. Prohibits visible emissions as dark as, or darker than, Ringelmann No. 1 for periods greater than three minutes in any hour.

Rule 402– Nuisance. Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.

Rule 403—Fugitive Dust. Prohibits visible dust emissions off property because of transport, handling, construction, or storage activity. Requires dust minimization during grading and clearing of land. Limits the difference between upwind and downwind PM concentrations of 100 µg/cubic meter (5 hour average). Requires removal of particulate matter from equipment prior to movement on paved streets.
Rule 403.2—Fugitive Dust Control for the Mojave Desert Planning Area. The project lies outside the Mojave Desert Planning Area, so the requirements of this rule do not apply.

Rule 404 – Particulate Matter. Prohibits PM emissions in excess grains per dry standard cubic foot (gr/dscf) limits based on the exhaust flow rate of the equipment in question. This rule applies to the auxiliary boiler and emergency fire pump engine at the proposed project.

Rule 406 – Specific Contaminants. Prohibits sulfur emissions, calculated as SO_2, in excess of 0.05% by volume (500 parts per million by volume [ppmv]), and acid gas emissions above specified levels. This rule applies to the gas turbine, auxiliary boiler, and emergency fire pump engine at the proposed project.

Rule 407 – Liquid and Gaseous Air Contaminants. Prohibits carbon monoxide emissions in excess of 2000 ppmv. This rule applies to the gas turbine and auxiliary boiler at the proposed project.

Rule 409 – Combustion Contaminants. Prohibits PM emissions in excess of 0.1 grains per dry standard cubic foot (gr/dscf) from combustion equipment. This rule applies to the gas turbine, auxiliary boiler and emergency fire pump engine at the proposed project.

Rule 431 – Sulfur Content of Fuels. Prohibits the burning of gaseous fuel with a sulfur content of more than 800 ppm and liquid fuel with a sulfur content of more than 0.5% sulfur by weight. This rule applies to the auxiliary boiler and emergency fire pump engine at the proposed project.

Rule 474 – Fuel Burning Equipment. Applies to nonmobile fuel burning equipment with a rated heat input in excess of 1,775 MMBtu/hr. Because the gas turbine is subject to Rule 1159, this rule does not apply.

Rule 475 – Electric Power Generating Equipment. Limits NOx and PM emissions from electrical generating equipment rated greater than or equal to 50 MMBtu/hr to RACT levels. Because the gas turbine is subject to Rule 1159, this rule does not apply.

Rule 476 – Steam Generating Equipment. Limits NOx emissions from steam generators rated above 50 MBtu/hr to 125 ppm. Because the proposed auxiliary boiler will have a nominal heat input of 66 MMBtu/hr, it will be subject to the requirements of this rule.

Rule 1158 – Electric Utility Operations. Limits NOx from existing electric power generating facilities within the Federal Ozone Nonattainment Area. The rule is not applicable to the proposed project because the project is not located within the Federal Ozone Nonattainment Area.

Rule 1159 – Stationary Gas Turbines. Limits NOx and CO emissions from stationary gas turbines. Based on the operating hours, emission control technology and output rating proposed for the new gas turbine, the applicable limits will be 5 ppmc[15] and 200 ppmc for NOx and CO, respectively.

Rule 1160 – Internal Combustion Engines. Limits emissions from internal combustion engines. Applies only to engines located within the Federal Ozone Nonattainment Area, which as defined in the rule includes only portions of San Bernardino County. Therefore this rule is not applicable to the proposed project.

3.1.4 Environmental Analysis

The following sections describe the emission sources that have been evaluated, the results of the ambient impact analyses, and the evaluation of project compliance with the applicable air quality regulations, including the District's NSR requirements. These analyses are designed to confirm that the proposed project's design features lead to less-than-significant impacts even with the following conservative analysis assumptions and procedures: maximum allowable emission rates, project operating schedules that lead to maximum emissions, worst-case meteorological conditions, and the worst-observed existing air quality added to the highest potential ground-level impact from modeling—even when all of these situations could not physically occur at the same time. The comparison of emissions and impacts for the proposed SEP and the licensed BEP II are presented in Section 3.1.10.

3.1.4.1 Project Description

The proposed SEP combined cycle power plant will encompass the following new stationary sources of emissions:

- One GE 7HA.02 gas turbine, rated at a nominal 3320 MMBtu/hr (HHV) (at 39°F)
- One heat recovery steam generator (HRSG) with duct burners, rated at 221.6 MMBtu/hr (HHV)
- One nominal 66 MMBtu/hr (HHV) auxiliary boiler to improve startup efficiency
- A ten-cell wet mechanical draft cooling tower
- One 238 HP diesel-fired emergency fire pump engine

The new gas turbine proposed for SEP is a GE 7HA.02 unit with duct firing and a steam turbine. The combustion turbine will be fueled exclusively with natural gas. The turbine will be equipped with an inlet air evaporative cooling system to maintain turbine power output across the full range of ambient temperatures. Based on duct-fired operation at an ambient temperature of 74°F, with evaporative cooling of the CTG inlet air to 58.7°F, the facility will have a gross heat rate of approximately 6,488 Btu/kWh (HHV).

The gas turbine will be equipped with dry low-NOx combustion technology and a SCR system for NOx control. An oxidation catalyst will be used to reduce CO emissions and will also reduce emissions of TACs. The auxiliary boiler will be equipped with low-NOx burners to minimize NOx emissions. Particulate, SOx, CO, and VOC emissions will be minimized through the use of natural gas as the fuel and through efficient operation. Emission control systems will operate at all times except during startups and shutdowns. The turbine is expected to operate as a baseload plant and will be available up to 24 hours per day, 7 days per week.

Gas turbine specifications are summarized in Table 3.1-17. Auxiliary boiler specifications are summarized in Table 3.1-18.

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[15] ppmc: parts per million by volume, dry, corrected to 15% O_2

Table 3.1-17. New Gas Turbine Design Specifications

Manufacturer	GE
Model	7HA.02
Fuel	Natural gas
Design Ambient Temperature [a]	39 °F
Nominal Gas Turbine Heat Input Rate[a] -- with duct firing -- without duct firing	 3,558 MMBtu/hr @ HHV 3,335 MMBtu/hr @ HHV
Nominal Power Output (Gas Turbine and Steam Turbine) -- with duct firing -- without duct firing	 543 MW 515 MW
Stack Exhaust Temperature [a]	158 °F
Exhaust Flow Rate [a]	1,637,212 acfm
Exhaust O_2 Concentration, dry volume [a]	12.09%
Exhaust CO_2 Concentration, dry volume [a]	5.05%
Exhaust Moisture Content, wet volume [a]	9.09%
Emission Controls	Dry low NOx combustor and SCR; oxidation catalyst
Stack Height	140 feet
Stack Diameter	22 feet

Notes:

[a] This ambient temperature at 100% load results in maximum heat input/power output; exhaust characteristics shown reflect this ambient temperature and load.

Table 3.1-18. New Auxiliary Boiler Design Specifications

Manufacturer/Model	Babcock & Wilcox FM Package Boiler or equivalent
Fuel	Natural gas
Nominal Heat Input Rate	66.3 MMBtu/hr @ HHV
Nominal Exhaust Temperature	600 °F
Nominal Exhaust Flow Rate	28,500 acfm
Nominal Exhaust O_2 Concentration, dry volume	3%
Emission Controls	Ultra Low-NO_x Burners (7.0 ppmv NO_x @ 3% O_2)
Stack Height	50 feet
Stack Diameter	35 inches

The natural gas fuel will meet the Public Utility Commission (PUC) grade specifications and will have a sulfur content not to exceed 0.5 grains per 100 dry standard cubic feet (dscf).[16] The diesel fuel sulfur will be limited to 15 ppm, and will meet all California low sulfur diesel specifications. Table 3.1-19 summarizes a typical analysis for the natural gas fuel to be used by the gas turbine, the duct burner, and the auxiliary boiler.

Table 3.1-19. Typical Natural Gas Specifications

Component Analysis		**Chemical Analysis**	
Component	**Average Concentration, Volume %**	**Constituent**	**Percent by Weight**
Methane (CH_4)	93.44	Carbon (C)	73.00%
Ethane (C_2H_6)	4.06	Hydrogen (H)	23.75%
Propane (C_3H_8)	0.45	Nitrogen (N)	2.29%
Butane (C_4H_{10})	0.10	Oxygen (O)	0.96%
Pentane (C_5H_{12})	0.02	Sulfur (S)	0.25 gr/100 scf
Hexane (C_6H_{14})	0.02		(annual average)
Nitrogen (N_2)	1.40	Higher Heating Value	1,036 Btu/scf
Carbon Dioxide (CO_2)	0.51		22,867 Btu/lb

The SEP will also contain a new emergency diesel fire pump engine rated at 238 bhp and a 10-cell mechanical draft cooling tower. Specifications for the new emergency diesel fire pump engine and cooling tower are provided in Appendix 3.1B, Tables 3.1B-4 and 3.1B-5.

3.1.4.2 Facility Operation

Combustion turbine performance specifications were developed for four ambient temperature scenarios: hot ambient temperature (110°F), annual average temperature (74°F), ISO temperature (59°F), and cold ambient temperature (39°F). The low-temperature scenario was used to characterize maximum hourly emissions because it has the highest hourly heat input and emission rates. The plant may be operated under a wide variety of conditions over its life. Maximum daily emissions are based on cold full-load operation of the CTG with 20 hours of duct firing and two startup/shutdown cycles, and 24 hours of operation for the auxiliary boiler, the emergency diesel fire pump engine and the cooling tower. Maximum annual emissions for the CTG/HRSG were based on 5,500 hours per year of baseload operation and 1,500 hours per year of duct firing, with 200 startup/shutdown cycles in addition to the 7,000 operating hours. Annual emissions for the auxiliary boiler were calculated based on a total of 7,000 hours of operation per year. Emergency diesel fire pump engine emissions were based on 200 hours of operation per year.

This operating profile was used to develop daily and annual heat input limits for the fuel-burning equipment. These heat input limits, summarized in Table 3.1-20, were used as the basis for calculating project emissions.

Table 3.1-20. Hourly, Daily and Annual Heat Input for the SEP Combustion Units

	Heat Input, MMBtu (HHV)		
Interval	**Gas Turbine**	**Auxiliary Boiler**	**Fire Pump Engine**
Hourly[a]	3,558	66.3	1.6

[16] 0.25 grains per 100 dry standard cubic feet on an annual average basis.

Table 3.1-20. Hourly, Daily and Annual Heat Input for the SEP Combustion Units

	Heat Input, MMBtu (HHV)		
Interval	**Gas Turbine**	**Auxiliary Boiler**	**Fire Pump Engine**
Daily[b]	84,500	1,600	38.8
Annual[c]	24,847,230	463,820	323

[a] Based on CTG performance at 39°F.

[b] 24 hr/day of operation for the CTG, including 20 hr/day of duct firing; 24 hr/day of operation for the auxiliary boiler and emergency fire pump engine.

[c] 7,000 hr/yr of operation for the CTG, including 1,500 hr/yr of duct firing; 7,000 hr/yr of operation for the auxiliary boiler; and 200 hr/yr of operation for the emergency fire pump engine. Based on CTG performance at 39°F.

Criteria pollutant emission rates were calculated for three components of the project: construction of the project, commissioning activities for the gas turbine/HRSG/steam turbine and auxiliary boiler, and operation. Tables containing the detailed calculations can be found in Appendix 3.1B.

3.1.4.3 Proposed Construction Emissions

Construction of the project will require both laydown and construction parking areas. SEP encompasses 76 acres of property, which will allow all laydown and construction parking to be accommodated on the project site. During the grading phase of the project, up to 10,000 cubic yards of fill material will be imported to the SEP site and approximately 50,000 cubic yards of excess soil will be removed from the site. The excess soil will be moved to an adjacent site owned by APHUS, north of the existing BEP facility.

Hourly, daily, and annual criteria pollutant emissions during construction were calculated based on the 26-month active construction schedule (including 4 months of commissioning) shown in Section 2, Project Description. Onsite and offsite project emissions have been divided into two categories: (1) vehicle and construction equipment exhaust; and (2) fugitive dust from vehicle and construction equipment, including grading and earthmoving during plant construction, and windblown dust.

The following criteria pollutant emissions have been calculated: NOx, SOx, VOC, CO, PM_{10}, and $PM_{2.5}$. Fugitive dust and construction equipment exhaust emissions have been estimated using methodology and emission factors consistent with the California Emissions Estimator Model (CalEEMod; version 2011.1.1), which incorporates OFFROAD2007 and portions of the EPA's AP-42 document (ENVIRON, 2011; SCAQMD et al., 2011). [17] Vehicle exhaust emissions for travel on both paved and unpaved roads were estimated using EMFAC2007 (version 2.3) emission factors, consistent with the CalEEMod methodology. Wind-blown fugitive dust emissions from earth movement and stockpiles and fugitive dust emissions for travel on both paved and unpaved roads were calculated external to the model.

Maximum daily and annual emissions were estimated based on the number and type of construction equipment, the number of heavy-duty trucks, and the workforce projected for each month of construction. It was conservatively assumed the construction activities will occur 10 hours per day and up to 23 days per month.[18] The maximum annual construction emissions will occur from month 7 through month 18 for all criteria pollutants.

[17] CalEEMod is a statewide computer model created by ENVIRON and the SCAQMD to quantify criteria pollutant and GHG emissions associated with the construction activities from a variety of land use projects (ENVIRON, 2011). Developed in cooperation with air districts throughout the state, CalEEMod is intended to standardize air quality analyses while allowing air districts to provide specific defaults reflecting regional conditions, regulations, and policies (SCAQMD et al., 2011). CalEEMod is generally viewed as an improvement and replacement of URBEMIS2007 by providing updated factors, methodologies, and defaults that are robustly documented.

[18] The number of construction days varies by month; see Appendix 3.1F.

The maximum daily and annual construction emissions are summarized and compared with MDAQMD CEQA thresholds in Table 3.1-21. The detailed emission calculations for construction are provided in Appendix 3.1C.

Table 3.1-21. Maximum Daily and Annual Emissions During Construction

Construction Emissions	NOx	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
Maximum Daily Emissions, lb/day	325	564	22	1.3	58	18
MDAQMD CEQA Significance Thresholds, lb/day[a]	137	548	137	137	82	82
Maximum Annual Emissions, tons/yr	16	34	1.3	0.1	5	1
MDAQMD CEQA Significance Thresholds, tons/yr[a]	25	100	25	25	15	15

Note: Maximum daily and annual emissions encompass contributions from project and linear construction activities. The PM_{10} and $PM_{2.5}$ emissions encompass exhaust and fugitive dust emissions.

[a] Source: "MDAQMD CEQA and Federal Conformity Guidelines," February 2009.

Emissions during construction will exceed the District's significance threshold for daily NOx and CO emissions. SEP will be required to submit a dust control plan to the District for approval prior to commencing construction, and mitigation measures will be used throughout the construction period to minimize emissions of all pollutants during this phase of the project. Mitigation measures during the construction period are discussed in more detail in Appendix 3.1C.

The maximum annual GHG emissions from construction activities are presented in Table 3.1-22. Project site construction equipment and on-site vehicle GHG emissions have been calculated in CalEEMod using emission factors from EPA's GHG Reporting Regulation[19] and fuel consumption rates from OFFROAD2007. No significant emissions of HFCs, PFCs, or SF_6 are expected during the construction.

The Council on Environmental Quality (CEQ) has provided draft guidance suggesting that quantities of direct GHG emissions equal to or greater than 25,000 metric tons of carbon dioxide equivalent (CO_2e) on an annual basis are meaningful and should be quantified and disclosed for project evaluations within the National Environmental Policy Act (NEPA) framework (CEQ, 2010). While this is not a NEPA evaluation, this threshold will be used as a guide for assessing whether GHG emissions from construction activities and mobile source emissions during operation may be meaningful. As presented in Table 3.1-22, the quantities of direct GHG emissions are well below 25,000 metric tons of CO_2e on an annual basis. Therefore, based on the draft CEQ guidance, as for the licensed project, the GHG emissions from the proposed project's construction activities will not be significant.

Detailed greenhouse gas emission and fuel use calculations for the construction period are shown in Appendix 3.1C.

Table 3.1-22. Maximum Annual Greenhouse Gas Emissions Estimates for Construction Activities

Greenhouse Gas Emissions	CO_2	CH_4	N_2O	CO_2 Equivalent
Total (metric tons)	5,090	0.66	0.00	5,107

CO_2 equivalent total assumes a 100-year global warming potential of 25 for CH_4 and 298 for N_2O (IPCC, 2007)

19 40 CFR 98 (as revised on 11/29/13).

GHG emissions from worker commutes and material deliveries were also calculated as part of the analysis. The GHG emissions are presented in Table 3.1-23. Emissions were estimated in the same manner as GHG emissions from construction activities.

Table 3.1-23. Greenhouse Gas Emissions from Worker Commute and Deliveries During Operation

	Greenhouse Gas Emissions (metric tons/year)			
Emission Source	**CO_2**	**CH_4**	**N_2O**	**CO_2 Equivalent**
Worker Commute, metric tons/year	56.1	0.003	0.0	56
Material Deliveries, metric tons/year	37.8	0.0002	0.0	38
Total	93.9	0.003	0.0	94

3.1.4.4 Initial Commissioning Emissions

Gas turbine commissioning is the process of initial startup, tuning, and adjustment of the new CTG and auxiliary equipment and of the emission control systems. The commissioning process will consist of sequential test operation of the gas turbine up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 1,250 hours of gas turbine operation, before the gas turbine is ready for emissions performance testing. Up to approximately 350 hours of operation will be required prior to installing the SCR and oxidation catalysts. The detailed gas turbine commissioning schedule is shown in Appendix 3.1B. In the permit application submitted to the MDAQMD, the project owner will be requesting that the District allow up to 1,250 hours of gas turbine operation prior to the initial compliance tests.

During part of this period, NOx emissions will be higher than normal operating levels because the NOx emission control system will not be installed and/or fully operational and because the gas turbine will not be tuned for optimum performance. CO emissions will also be higher than normal because turbine performance will not be optimized and the CO emissions control system will not be installed or fully operational.[20] Emission rates for PM_{10}, $PM_{2.5}$, and SOx during initial commissioning are not expected to be higher than normal operating emissions because emissions from these pollutants are related to fuel use.

Gas turbine commissioning activities can be broken down into several separate test phases, as shown in the commissioning summary table included in Appendix 3.1B. The emission estimates shown in the detailed commissioning summary table in Appendix 3.1B are based on the emission rates and commissioning schedule provided by the gas turbine supplier. Estimated emissions of criteria pollutants during the commissioning phase are summarized in Table 3.1-24.

Table 3.1-24. Maximum Initial Commissioning Emissions for the SEP Gas Turbine

Period	NOx	SO_2	CO	VOC	$PM_{10}/PM_{2.5}$
CTG/HRSG, lb/hr	625	4.9	4,919	464	8.0

[20] Some of the commissioning test phases must be carried out at such low turbine loads that turbine exhaust temperatures are not able to reach levels at which the oxidation catalyst will be fully operational.

Table 3.1-24. Maximum Initial Commissioning Emissions for the SEP Gas Turbine

Period	NOx	SO_2	CO	VOC	$PM_{10}/PM_{2.5}$
CTG/HRSG, lb/day	15,610	118	28,500	2,620	211
CTG/HRSG, total tons	70	3.1	22	3.0	4.9

At the conclusion of the commissioning period, emissions rates will be at the normal operating levels discussed in the following section. While the required continuous emissions monitoring system (CEMS) for NOx and CO will be calibrated and operating during the commissioning test phases, the CEMS will be not certified until the end of the commissioning period.

Steam from the auxiliary boiler will be required during the gas turbine commissioning period. Therefore, the auxiliary boiler will undergo tuning to optimize the low-NOx burner operation prior to commencement of gas turbine commissioning. The boiler will need to operate for up to 200 hours during an initial commissioning period to allow for initial operation and tuning. During the commissioning period, uncontrolled NOx emissions from the auxiliary boiler may be up to 100 ppmvd, or 0.12 lb/MMBtu. Until the boiler is tuned, CO emissions may be up to 250 ppmvd, or 0.18 lb/MMBtu.

3.1.4.5 Proposed Criteria Pollutant Emissions During Project Operation

Operational emission estimates were prepared for turbine startup and shutdown modes and steady-state operation. Emission estimates for these operating modes are based on vendor data and engineering estimates. Natural gas will be the only fuel burned in the turbine and duct burner. The turbine will use dry low NOx combustors, combined with SCR, to limit emissions of NOx to 2.0 ppmv, dry, corrected to 15 percent O_2 (ppmc), on a 1-hour average basis, and to 1.5 ppmc on an annual average basis. Best combustion practices, combined with the use of an oxidation catalyst, will be used to limit CO emissions to 2.0 ppmc on a 1-hour average basis, and 1.5 ppmc on an annual average basis. VOC emissions will be limited to 2.0 ppmc during duct firing and 1 ppmc without duct firing. PM_{10} and SO_2 emissions will be kept to a minimum through the exclusive use of natural gas.

Startup and Shutdown Emissions. During the startup and shutdown operating modes, the emission control systems are not fully functional, which may result in higher air emission rates relative to the steady-state operating mode. The startup and shutdown of this fast-start gas turbine occurs in a relatively short time (well under one hour).

The time from fuel initiation until minimum compliant operating load is reached is expected to take up to 45 minutes for cold, warm, and hot starts. Although the exhaust emissions are expected to reach BACT levels sooner, these startup periods provide a conservative estimate of the time for the SCR and oxidation catalyst systems to reach their respective operating temperatures and to achieve allowable BACT emission levels.

The plant has been designed to accommodate two types of fast starts: Rapid Response and Rapid Response Lite. Rapid Response takes the gas turbine to base load as quickly as possible, while Rapid Response Lite takes the gas turbine to minimum emissions-compliant load (nominally 40% load) as quickly as possible. SEP expects to use the Rapid Response Lite startup procedures most of the time; however, at times of high demand, the Rapid Response startup procedures will be used. The Rapid Response procedure requires more auxiliary boiler steam and has slightly higher emissions over the startup period. To be conservative, all startups were assumed to be under Rapid Response conditions (that is, higher auxiliary boiler load and higher gas turbine emissions). Emissions for both Rapid Response and Rapid Response Lite startups are shown in Appendix 3.1B, Table 3.1B-2.

The gas turbine startup and shutdown emission rates are presented on a pound-per-event (lb/event) and a pound-per-hour (lb/hr) basis in Table 3.1-25. The startup and shutdown event data are based on manufacturer data and engineering estimates. The hourly startup and shutdown emission rates assume that for the remainder of the hour following completion of the startup, the turbine operates at full load.

Table 3.1-25. Facility Startup/Shutdown Emission Rates[a]

	Time Required to Reach Emissions Compliance, minutes	NOx	CO	VOC	$PM_{10}/PM_{2.5}$
Cold Start					
Startup (lb/event)[b]	45	181	132	10	6.6
Startup (lb/hr)[c]	--	188	136	12	9.1
Warm Start					
Startup (lb/event)[b]	40	146	130	10	5.9
Startup (lb/hr)[c]	--	155	135	13	9.2
Hot Start					
Startup (lb/event)[b]	21	97	123	9	3.1
Startup (lb/hr)[c]	--	114	133	15	9.6
Shutdown					
Shutdown (lb/event)[b]	14	4.9	136	28	2.1
Shutdown (lb/hr)[c]	--	25	148	35	9.8

[a] Emission rates shown reflect Rapid Response startup procedures. See text.

[b] Emission rates provided by GE.

[c] NOx, CO, VOC and PM_{10} emissions for the balance of the hour were based on the hourly emission rate for 100 percent load, with duct firing, at 39°F.

Emissions During Normal Operation. Turbine performance data are provided in Appendix 3.1B, Table 3.1B-1. Hourly emissions of NOx, CO, and VOC were calculated from emission limits (in ppmv @ 15 percent O_2) and the exhaust flow rates. The NOx emission limit reflects the application of SCR. The VOC emission limit reflects the use of good combustion practices. The CO emission limit reflects the expected performance of the oxidation catalyst. Maximum emissions were based on the heat input rates shown in Table 3.1-20. SO_2 emissions were calculated based on the maximum allowable fuel sulfur content of 0.5 grain per 100 standard cubic feet (scf) and the hourly heat input rate in Table 3.1-20. Maximum hourly PM_{10} emissions reflect expected turbine performance, based on emissions limits from similar installations. $PM_{2.5}$ emissions were determined based on the assumption that all particulate matter emissions are less than 2.5 microns in size.

Maximum hourly emission rates are summarized in Table 3.1-26. The BACT analysis upon which the emission factors are based is presented in Appendix 3.1D.

An evaporative cooler will be used to cool the gas turbine inlet air and increase efficiency at higher ambient temperatures. The evaporative cooler will be a closed-loop system and will have no air emissions.

Table 3.1-26. Maximum Pollutant Emission Rates for the 7HA Gas Turbine[a]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu	Emission Rate (lb/hr)	
			With duct firing	No duct firing
NOx	2.0 (1-hour)	0.0073	26.0	24.2
	1.5 (annual average)	0.0055	--	--
CO	2.0 (1-hour)	0.0044	15.8	14.8
	1.5 (annual average)	0.0033	--	--
VOC	2.0 (3-hour) (w/ duct firing)	0.0025	9.0	--
	1.0 (3-hour) (no duct firing)	0.0013	--	4.2
SO_2 [d]	n/a[c]	0.0021	4.9	4.6
PM_{10} /$PM_{2.5}$ [b]	n/a	n/a	10	8

[a] Maximum values are for the turbine at an ambient temperature of 39°F and exclude startups and shutdowns.

[b] 100 percent of particulate matter emissions assumed to be emitted as PM_{10} and $PM_{2.5}$.

[c] Not applicable.

[d] Estimated using a maximum of 0.5 grains of sulfur per 100 dscf of natural gas.

Auxiliary Boiler Emissions. The auxiliary steam boiler will provide steam during gas turbine startup and shutdown to allow startups and shutdowns to be accomplished more quickly. During prestart activities and during the initial phases of start-up, steam for sealing, warming the steam turbine, and heating/reheating condensate (condenser sparging steam) will be supplied from the auxiliary boiler. Annual boiler emissions for all pollutants are calculated based on 7,000 hours per year of operation.

During normal project operation, and as a worst case, the auxiliary boiler is expected to undergo one startup/shutdown event for each gas turbine startup. The auxiliary boiler is assumed to require up to 2 hours to come into compliance with the proposed NOx, CO, and VOC limits. Boiler shutdowns are expected to occur quickly enough that emissions during those periods will not exceed normal limits on a three-hour average basis. Therefore, the auxiliary boiler is assumed to have up to 2 hours per day of elevated NOx, CO and VOC emissions as a result of startup and shutdown activities.

Emission rates for the auxiliary boiler during commissioning, startup, and normal operation are shown in Table 3.1-27. The maximum hourly, daily and annual heat inputs to the boiler, summarized in Table 3.1-20, were used as the basis for calculating hourly, daily, and annual emissions shown.

Table 3.1-27. Emission Rates for the Auxiliary Boiler

Pollutant	Emissions		
	ppmvd @ 3% O_2	lb/MMBtu	lb/hr
NOx (normal operation)	7	0.0084	0.6
NOx (startup/shutdown)	25	0.03	2.0
NOx (tuning)	100	0.12	8.0
SOx	1.26[a]	0.0014	0.1
CO (normal operation)	50	0.037	2.4
CO (startup/shutdown/tuning)	250	0.18	12.1
VOC (normal operation)	7	0.004	0.3
VOC (startup/shutdown/tuning)	25	0.015	1.0
PM_{10}/$PM_{2.5}$	--	0.007	0.5

[a] Based on maximum fuel sulfur content of 0.5 grains per 100 scf.

Wet Cooling Tower Emissions. Particulate emissions result from evaporation of the cooling water. Drift will be minimized through the use of a high-efficiency drift eliminator. Treated well water will be used for makeup water, and the total dissolved solids (TDS) level of the recirculating water is expected to be approximately 5000 ppmw after concentration.

Details of the cooling water drift calculation for the wet cooling tower are shown in Appendix 3.1B, Table 3.1B-5. Particulate emissions from the cooling tower will be about 1.6 pounds per hour.

Facility Emissions. Maximum hourly NOx, CO and VOC emissions are expected to occur during a gas turbine startup. Since the time from ignition to fully controlled operation is under 60 minutes, NOx, CO and VOC emissions during the remainder of the hour will be at controlled emission levels with duct firing. The detailed CTG startup hourly emissions are shown in Table 3.1-25, along with the startup/shutdown emission rates and durations supplied by the gas turbine vendor. Because SOx emissions are based on fuel consumption, the maximum hourly SOx emissions are based on the turbine operating at full load at the minimum ambient temperature.

Gas turbine performance specifications were evaluated for four ambient temperature scenarios: extreme hot temperature (110^{o}F), annual average temperature (74^{o}F), ISO temperature (59^{o}F) and extreme low temperature (39^{o}F). The cold temperature scenario (or cold startup scenario) was used to characterize maximum hourly emissions during normal operation because it has the highest hourly heat input and emission rates. The worst-case day is defined as follows:[21]

- 1 hour in cold start mode
- 20 hours of base load operation w/duct firing
- 1 hour in hot start mode
- 2 hours in shutdown mode

The annual emissions profile assumes that the plant will operate 7,000 hours per year, which is based on 5,500 hours per year of turbine operation without duct firing and 1,500 hours per year with duct firing, plus 50 cold starts, 150 warm starts, and 200 shutdowns (400 hours in startup/shutdown mode). Because the facility will utilize GE's "Rapid Response" design, startups will require less than 1 hour; the actual time required will depend upon the condition of the gas turbine (that is, the down-time prior to start, which determines whether the startup is defined as cold, warm, or hot).[22] Associated with the Rapid Response design will be an auxiliary boiler that will operate up to approximately 7,000 hours per year, including up to about 400 hours per year of startup. Annual emissions show the emergency fire pump engine operating a total of 200 hours per year. The assumptions used in calculating maximum hourly, daily, and annual emissions from the new facility are shown in Appendix 3.1B.

Maximum hourly, daily, and annual emissions for the proposed project are presented in Table 3.1-28. Detailed calculations are provided in Appendix 3.1B, Table 3.1B-6.

[21] The daily emissions calculation for NOx, CO, and VOC encompass startup and shutdown hours. SOx and PM_{10} emissions are not higher during startups or shutdowns, so daily emissions of these pollutants are based on 24 hours of full load operation with duct firing.

[22] Startup times shown are the times required to achieve compliance with permitted emission limits.

Table 3.1-28. SEP Facility Emissions

	NOx	SO_2	VOC	CO	PM_{10}/ $PM_{2.5}$
Maximum Hourly Emissions[a], lb/hr	188.1	5.0	12.5	138.4	12.1
Maximum Daily Facility Emissions[b], lb/day	919.6	120.0	286.0	966.6	289.3
Maximum Annual Facility Emissions[c], tpy	85.6	8.8	24.2	78.0	40.1

[a] Maximum hourly NOx, CO, and VOC emissions were based on a startup hour. The maximum hourly PM_{10}, $PM_{2.5}$, and SOx emissions are based on turbine operation at full load with duct firing at the minimum ambient temperature and include the auxiliary boiler and cooling tower.

[b] Maximum daily emissions are based on 2 startups and 2 shutdowns, with the remaining hours at full load with duct firing; and 24 hours of operation for the auxiliary boiler, emergency fire pump engine and cooling tower.

[c] Maximum annual emissions are based on 200 startups, 200 shutdowns, and 7,000 total hours of operation at 100 percent load, 74°F, for each turbine; 400 hours of startup and 7,000 total hours of operation for the auxiliary boiler; 8,760 hours of operation for the cooling tower; and 200 hours per year of operation for the emergency fire pump engine.

tpy = ton(s) per year

3.1.4.6 Noncriteria Pollutant Emissions During Project Operation

Noncriteria pollutant emissions were estimated for the proposed new equipment. These emissions are summarized in Table 3.1-29.[23] The detailed noncriteria pollutant emissions calculations are provided in Appendix 3.1B and the associated screening-level health risk assessment is shown in Section 3.8, Public Health. Shown in Table 3.1-30 is a summary of the maximum potential to emit for noncriteria pollutants for the existing units at the same stationary source (BEP). This information is provided for regulatory applicability purposes and is discussed further below.

As discussed in Section 3.1.1.1, the previously-licensed BEP II and the existing BEP were not under common ownership or control at the time either project was licensed and were treated as separate stationary sources for federal regulatory purposes. In contrast, the proposed SEP and the existing BEP are under common ownership and are considered a single stationary source under federal regulations. Therefore, total emissions from both projects must be compared with regulatory thresholds to determine whether the stationary source is a major source of hazardous air pollutants (HAPs).

Table 3.1-29. Noncriteria Pollutant Emissions for the New Equipment

	Emissions, tons per year			
Compound	**Gas Turbine/HRSG**	**Auxiliary Boiler**	**Fire Pump Engine**	**Total**
Ammonia (not a HAP)	81.7	--	--	81.7
Propylene (not a HAP)	4.7	0.03	--	4.7
Diesel PM (not a HAP)	--	--	1.06×10^{-2}	1.06×10^{-2}
Acetaldehyde	0.25	1.99×10^{-3}	--	0.25
Acrolein	0.04	6.04×10^{-4}	--	0.04
Benzene	0.07	9.65×10^{-3}	--	0.07
1,3-Butadiene	2.67×10^{-3}	--	--	2.67×10^{-3}

23 There will also be small quantities of noncriteria pollutant emissions from the cooling tower, resulting from trace amounts of impurities in the circulating water. These are quantified in Appendix 3.1B and are part of the screening health risk assessment.

Table 3.1-29. Noncriteria Pollutant Emissions for the New Equipment

	Emissions, tons per year			
Compound	**Gas Turbine/HRSG**	**Auxiliary Boiler**	**Fire Pump Engine**	**Total**
Ethylbenzene	0.20	1.54×10^{-3}	--	0.20
Formaldehyde	5.59	4.95×10^{-2}	--	5.64
Hexane	1.58	1.03×10^{-3}	--	1.58
Naphthalene	0.01	6.72×10^{-5}	--	0.01
PAHs (other)	4.00×10^{-3}	2.24×10^{-5}	--	4.02×10^{-3}
Propylene Oxide	0.18	--	--	0.18
Toluene	0.81	5.93×10^{-3}	--	0.87
Xylene	0.40	4.41×10^{-3}	--	0.44
Total HAPs (Proposed Project)	**9.1**	**6.6×10^{-2}**	**--**	**9.2**

Table 3.1-30. Noncriteria Pollutant Emissions for the Existing BEP

Compound	Emissions (tons/yr)
Ammonia (not a HAP)	213.9
Propylene (not a HAP)	6.1
Acetaldehyde	0.32
Acrolein	0.05
Benzene	0.10
1,3-Butadiene	3.42×10^{-3}
Ethylbenzene	0.25
Formaldehyde	7.17
Hexane	2.02
Naphthalene	0.01
Other PAHs	5.12×10^{-3}
Propylene Oxide	0.23
Toluene	1.04
Xylene	0.51
Total HAPs (Existing Facility)	**11.7**

Although total combined HAP emissions from the two facilities are below the 25 ton per year major source threshold applicable to total HAP emissions, total potential formaldehyde emissions are

12.8 tons/yr, in excess of the 10 ton/yr major source threshold for a single HAP. Therefore, the two facilities will be a major source of HAP under federal regulations.

3.1.4.7 Greenhouse Gas Emission Estimates

GHG emissions for normal facility operation were calculated based on the maximum fuel use predicted for project operation and emission factors contained in the EPA GHG Reporting Regulation.[24] GHG emissions resulting from project operation are presented in Table 3.1-31.

Table 3.1-31. Project Greenhouse Gas Emissions

	CO_2, metric tons/year	CH_4, metric tons/year	N2O, metric tons/year	SF6, metric tons/year	CO_2eq, metric tons/yr[a]	CO_2, metric tons/MWh (gross/net)[b]
Gas turbine	1,318,394	24.5	2.5	--	--	--
Auxiliary boiler	24,610	0.5	0.05	--	--	--
Fire pump engine	21	0.001	0.0002	--	--	--
Circuit breakers	--	--	--	0.001	--	--
Total Emissions	1,343,025	25	2	0.001	1,344,428	0.35/0.36

[a] Shows CH_4, N_2O, and SF_6, weighted by their global warming potential.

[b] Reflects gross and net rated output of the plant. See Appendix 3.1B, Table 3.1B-9.

The estimated emissions encompass the combustion emissions for the gas turbine and duct burners, the auxiliary boiler, and the emergency diesel fire pump engine. They also encompass sulfur hexafluoride emissions from potential leaks of the 13 new circuit breakers. The project impact assessment evaluates the impacts from potential emissions of SF_6 in addition to emissions of CO_2, CH_4, and N_2O.

The annual fuel use upon which these calculations were based is provided in Table 3.1-20. The detailed GHG emission calculations are included in Appendix 3.1B, Table 3.1B-9.

3.1.4.8 Emissions Reductions at Blythe Energy Project

The owner of BEP is proposing to reduce the hourly and annual PM_{10} mass emission limits and the annual SO_2 mass emission limits in the current Permit to Operate (PTO) and Title V operating permit for the two existing gas turbines at existing BEP.

Hourly and Annual PM10 Emissions. When these turbines were originally permitted in 2000, gas turbine manufacturers had limited PM emissions test data from in-use gas turbines. The test data they did have showed significant variation in PM emission rates because of variability in source test conditions and procedures. Therefore, PM emissions guarantees provided by gas turbine manufacturers were relatively high. However, refinements in PM test methods and improved quality control procedures have significantly reduced the variability in PM test results, and have improved the accuracy of PM testing at low concentrations.[25] PM_{10} source tests on the BEP gas turbines demonstrate that PM_{10} emissions are consistently well below the permitted emission rate of 11.5 pounds per hour (lb/hr). As an example, PM_{10} test results from the 2014 annual source testing of the BEP gas turbines are summarized in Table 3.1-32.

Based on these test results, the owner of BEP is proposing to reduce the hourly PM_{10} limit for each gas turbine from the current level of 11.5 lb/hr to 6.2 lb/hr. PM_{10} emissions changes for the gas turbines are summarized in Table 3.1-33.

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24 40 CFR 98 (as revised on 11/29/13).

25 Matis, Craig, Glenn England et al, “Evaluation of CTM-039 Dilution Method for Measuring PM_{10}/$PM_{2.5}$ Emissions from Gas-Fired Combustion Turbines,” August 20, 2009.

Table 3.1-32. 2014 PM_{10} Test Results

	PM_{10} Emission Rate, lb/hr			
Unit	**Run 1**	**Run 2**	**Run 3**	**Average**
Unit 1	4.6	1.6	1.5	2.5
Unit 2	2.4	2.7	0.8	1.9

Table 3.1-33. Emissions Changes: PM_{10} from the BEP Gas Turbines

	Period	
	lb/hr	**lb/day**
Proposed permit limit		
– per unit	6.2	–
– total, both units	–	298.5
Current permit limit		
– per unit	11.5	–
– total, both units	–	565
Net change		
– per unit	(5.3)	–
– total, both units	(10.6)	(266.5)

A review of emissions data for the gas turbines, including annual emission reports, confirms that actual emissions of PM are well below permitted limits. Therefore, the owner of BEP is also proposing to reduce the annual PM limit in the gas turbine PTO to more closely reflect actual gas turbine performance. Table 3.1-34 summarizes the annual PM emissions as reported by the facility for calendar years 2012, 2013, and 2014. PM_{10} emissions from the gas turbines are calculated using an emission factor of 10 lb/hr. Reducing the hourly emission limit for the gas turbines to 6.2 lb/hr will reduce the historical annual emissions by nearly 40 percent.

Based on these historical emissions, the owner of BEP is confident that facility-wide annual emissions of PM_{10} can be maintained below 56.9 tpy under all future operating conditions. The owner of BEP is proposing to reduce the annual PM_{10} limit to 56.9 tons with compliance to be determined on a 12-month rolling total basis. Table 3.1-35 summarizes the proposed reduction in permitted annual PM_{10} emissions.

Table 3.1-34. Historical Annual Emissions from the BEP Gas Turbines

	Unit	**Reported Emissions, tpy[a]**			
Pollutant		**2012**	**2013**	**2014**	**Maximum**
PM	Total including cooling towers	45.9	46.2	42.2	46.2

Note:

[a] Annual emissions from the gas turbines were calculated using an emission factor of 10 lb/hr. Emissions will be significantly lower when calculated using the proposed new hourly emission limit of 6.2 lb/hr.

Table 3.1-35. Proposed Reductions in Permitted Annual PM_{10} Emissions

	PM_{10} Permit Limit, tons per year [a]
Proposed permit limit	56.9
Current permit limit	97
Net change	(40.1)

Note:

[a] PM_{10} limits encompass emissions from the cooling towers.

Annual SO2 Emissions. The annual SO_2 emission limit for BEP was based on a maximum annual average natural gas fuel sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf). As shown in Table 3.1-36, more recently licensed projects, including BEP II, have assumed a significantly lower annual average sulfur content in calculating their annual SO_2 potential to emit.

Table 3.1-36. Sulfur Content Assumptions for Recent Projects Approved in the Project Area

Project Name	Year Filed/Year Approved	Maximum Annual Average Sulfur Content of Natural Gas
Victorville Hybrid	2007/2008	0.2 gr/100 scf
Genesis Solar	2009/2010	<0.1 gr/100 scf
Abengoa Mojave Solar	2009/2010	0.2 gr/100 scf
Blythe Solar	2009/2012	0.2 gr/100 scf
BEP II	2010/2012	0.25 gr/100 scf

The project owner will maintain the 0.5 gr/100 scf as a short-term limit for BEP (that is, for hourly and daily SO_2 emissions calculations), but will propose a new limit of 0.25 gr/100 scf that will be applicable on an annual average basis. This will reduce BEP's SO_2 annual potential to emit from 24 tpy to 12 tpy.

Simultaneous Emissions Reductions. The owner of BEP was required to surrender emission reduction credits (ERCs) to offset the original permitted emissions of PM from the project. Because the permitted emissions from BEP are being reduced, the offset obligation will also be reduced. In accordance with District Rule 1305 (B)(2)(b), which discusses Actual Emission Reductions generated by simultaneous reductions at a facility:

> *[Actual Emissions Reductions] generated from Federally Enforceable reductions in a Facility's Potential to Emit may be used as Offsets if the [Historic Actual Emissions] for the Facility or Emissions Unit which is proposed for a Federally Enforceable reduction in its Potential to Emit was completely offset in a prior permitting action pursuant to this Regulation.*

While Actual Emission Reductions generated by simultaneous reductions at a facility are not eligible for banking as ERCs, they can be used to reduce the offset liability of a proposed modification. The owner of BEP completely offset the facility's PM_{10} Potential to Emit by providing 103 tons of PM_{10} ERCs prior to commencing construction on the facility. The facility Potential to Emit is proposed to be reduced by 40.1 tons of PM_{10}, and under Rule 1305(B)(2)(b), this reduction may be used as a simultaneous emissions reduction to offset PM_{10} emissions increases that will result from the proposed addition of the SEP at this stationary source.

3.1.5 Air Quality Impact Analysis

The MDAQMD new source review regulations require the project owner to prepare ambient air quality modeling analyses and other impact assessments. An ambient air quality impact assessment is also required by the CEC for CEQA review. These analyses are presented in this section.

3.1.5.1 Air Quality Modeling Methodology

An assessment of impacts from the proposed project on ambient air quality has been conducted using EPA-approved air quality dispersion models. These models use a mathematical description of atmospheric turbulent entrainment and dispersion to simulate the actual processes by which emissions are transported to ground-level areas.

Based on conservative assumptions, modeling was used to determine the maximum ground-level impacts of the project. The results were compared with state and federal ambient air quality standards and PSD significance levels.[26] If the standards are not exceeded in the analysis, then the facility will cause no exceedances under any operating or ambient conditions, at any location, under any meteorological conditions. In accordance with the air quality impact analysis guidelines developed by EPA[27] and ARB,[28] the ground-level impact analysis encompasses the following assessments:

- Impacts in simple, intermediate, and complex terrain
- Aerodynamic effects (downwash) as a result of nearby building(s) and structures
- Impacts from inversion breakup (fumigation)

Simple, intermediate, and complex terrain impacts were assessed for all meteorological conditions that will limit the amount of final plume rise. Plume impaction on elevated terrain, such as on the slope of a nearby hill, can cause high ground-level concentrations, especially under stable atmospheric conditions. Another dispersion condition that can cause high ground-level pollutant concentrations is caused by building downwash. A stack plume can be impacted by downwash when wind speeds are high and a sufficiently tall building or structure is in close proximity to the emission stack. This can result in building wake effects where the plume is drawn down toward the ground by the lower pressure region that exists in the lee (downwind) side of the building or structure.

Fumigation conditions occur when the plume is emitted into a layer of stable air (inversion) that then becomes unstable from below, resulting in a rapid mixing of pollutants out of the stable layer and towards the ground in the unstable layer underneath. The low mixing height that results from this condition allows little dispersion of the stack plume before it is carried downwind to the ground. Although fumigation conditions are short-term, rarely lasting as long as an hour, relatively high ground-level concentrations may be reached during that period. Fumigation tends to occur under clear skies and light winds, and is more prevalent in summer. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack and “fumigates” the air below.

The basic model equation used in this analysis assumes that the concentrations of emissions within a plume can be characterized by a Gaussian (statistical) distribution around the centerline of the plume. Concentrations at any location downwind of a point source such as a stack can be determined from the following equation:

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[26] Although the project is not subject to PSD review, the PSD significance levels may be used as one potential measure of significance under CEQA.

[27] EPA. Guideline on Air Quality Models, 40 CFR Part 51, Appendix W.

[28] ARB. Reference Document for California Statewide Modeling Guideline, April 1989.

$$C(x,y,z,H) = \left(\frac{Q}{2\pi\sigma_y\sigma_z u}\right) * \left(e^{-1/2\left(y/\sigma_y\right)^2}\right) * \left[\left\{e^{-1/2\left(z-H/\sigma_z\right)^2}\right\} + \left\{e^{-1/2\left(z+H/\sigma_z\right)^2}\right\}\right] \quad \text{(Eq. 1)}$$

where

C = pollutant concentration in the air

Q = pollutant emission rate

$\sigma y \sigma z$ = horizontal and vertical dispersion coefficients, respectively, at downwind distance x

u = wind speed at the height of the plume center

x,y,z = variables that define the downwind, crosswind, and vertical distances from the center of the base of the stack in the model's three-dimensional Cartesian coordinate system

H = the height of the plume above the stack base (the sum of the height of the stack and the vertical distance that the plume rises as a result of the momentum and thermal buoyancy of the plume)

Gaussian dispersion models are approved by EPA for regulatory use and are based on conservative assumptions (i.e., the models tend to overpredict actual impacts by assuming steady-state conditions, no pollutant loss [through conservation of mass], no chemical reactions). The EPA models were used to determine if ambient air quality standards will be exceeded, and whether a more accurate and sophisticated modeling procedure will be warranted to make the impact determination. Described in the subsections below are the following:

- Gas turbine screening modeling
- Refined air quality impact analysis
- Specialized modeling analyses
- Results of the ambient air quality modeling analyses
- PSD significance levels

Modeling for the proposed project was performed in accordance with the modeling protocol submitted to the MDAQMD and CEC found in Appendix 3.1E. The modeling procedures used for each type of modeling analysis are described in more detail in the following sections.

Two different EPA guideline models were used for different meteorological conditions in the ambient air quality impact analysis: AERMOD[29] and SCREEN3.

The EPA-approved AERMOD model was used to evaluate impacts in simple, intermediate, and complex terrain. AERMOD is a Gaussian dispersion model capable of assessing impacts from a variety of source types in areas of simple, intermediate, and complex terrain. The model can account for settling and dry deposition of particulates; area, line, and volume source types; downwash effects; and gradual plume rise as a function of downwind distance. The model is capable of estimating concentrations for a wide range of averaging times (from one hour to one year), and was applied with five years of actual meteorological data recorded at the Blythe monitoring station.

The SCREEN3 model was used to evaluate gas turbine and auxiliary boiler impacts under inversion breakup conditions because these are special cases of meteorological conditions. The SCREEN3 model uses a range of meteorological conditions that could occur under inversion breakup. Since the emissions from the emergency engine are small compared to the gas turbine emissions, they are excluded from this single-source model used for the fumigation analysis. The fumigation analysis is discussed in more detail below.

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29 The acronym AERMOD was derived from <u>A</u>merican Meteorological Society/<u>E</u>nvironmental Protection Agency <u>R</u>egulatory <u>Mod</u>el.

The air dispersion modeling was conducted based on guidance presented in the *Guideline on Air Quality Models* (EPA, 2005) and the EPA-approved dispersion model, AERMOD (version 14134), and as described in the modeling protocol that was submitted to the agencies and included in the PTA as Appendix 3.1E (Sierra Research, 2014). Modeling results are provided on compact disc.

Model Selection. The AERMOD model is a steady-state, multiple-source, dispersion model that incorporates hourly meteorological data inputs and local surface characteristics. The AERMOD model is well suited for this assessment based on the ability of the model to handle the various physical characteristics of project emission sources, including point, area, and volume source types. The required emission source data inputs to AERMOD encompass source locations, source elevations, stack heights, stack diameters, stack exit temperatures, stack exit velocities, and pollutant emission rates. The source locations are specified for a Cartesian (x,y) coordinate system where x and y are distances east and north in meters, respectively. The Cartesian coordinate system used for these analyses is the Universal Transverse Mercator Projection (UTM), 1983 North American Datum (NAD 83).

Where noted, the NO_2 1-hour modeling was refined using AERMOD's Ozone Limiting Method (OLM) model option. OLM offers a more realistic approach to calculating concentrations of NO_2 by accounting for the fact that only a portion of the NOx emitted from the gas turbine stacks is in the form of NO_2. The remaining stack gas is released as nitrogen oxide. In the atmosphere, nitrogen oxide chemically reacts with ambient concentrations of ozone to form NO_2. The OLM option calculates NO_2 concentrations based on the ambient ozone concentrations using this principle. The hourly ozone data used for the OLM analysis were collected at the nearby Blythe monitoring station between 2009 and 2013 and preprocessed for use with AERMOD in accordance with the procedures described in the modeling protocol.

Model Options. The following technical options were selected for the AERMOD model:

- Regulatory default control options
- Rural dispersion mode because land use within 3 kms of the project is primarily classified as rural based on the Auer Land Use Procedure (EPA, 2005)
- Receptor elevations and controlling hill heights obtained from AERMAP (Version 11103) output

Meteorological Data. The CEC requires a minimum of one year of meteorological data approved by ARB or the local air pollution control district to be used in the air dispersion modeling analysis. EPA modeling guidance recommends use of a minimum of three years of meteorological data collected at the nearest station to the project site. According to EPA's Guideline on Air Quality Models (EPA, 2005), representativeness of meteorological data used in dispersion modeling depends on (1) the proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected.

The Blythe monitoring station is located less than 2 miles west of the proposed project site. There are no complex terrain features between the monitoring site and the project site. The land uses surrounding the monitoring site and the project site are similar. The surface meteorological data collected at the Blythe monitoring station for the period of January 1, 2009, through December 31, 2013, were compiled and preprocessed using the AERMET preprocessor. The surface data have also been coupled with the National Climatic Data Center soundings from the Elko, NV, National Weather Service station (Station #04105). The representativeness of the surface and upper air data is discussed in detail in the modeling protocol in Appendix 3.1E.

The annual and quarterly wind rose plots for the Blythe meteorological station are presented in Appendix 3.1A.

Receptor Grid Spacing. Cartesian coordinate receptor grids were used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid was developed that extended outwards at least 10 km (or more if necessary to establish the significant impact area).

For the full impact analyses, a nested grid was developed to fully represent the maximum impact area(s). The receptor grid was constructed as follows:

- One row of receptors spaced 25 meters apart along the facility's fence line
- Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line
- Additional tiers of receptors spaced 100 meters apart, extending from 100 meters to 1,000 meters from the fenceline
- Additional tiers of receptors spaced 250 meters apart, out to at least 10 km from the most distant source modeled, not to exceed 50 km from the project site

Additional refined receptor grids with 25-meter resolution were placed around the maximum first-high or maximum second-high coarse grid impacts and extended out 1,000 meters in all directions. Concentrations within the facility fencelines (BEP and SEP project fencelines) were not calculated. The coarse and refined receptor grids are presented in Appendix 3.1F.

Building Downwash and Good Engineering Practice Assessment. For the analysis of the potential turbine impacts during operation, EPA's BPIP-Prime (Building Profile Input Program – Plume Rise Model Enhancement, Version 04274) was used to calculate the projected building dimensions required for AERMOD evaluation of impacts from building downwash.

Good engineering practice (GEP), as used in the modeling analyses, is the maximum allowed stack height to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles. In addition, the GEP modeling restriction ensures that any required regulatory control measure is not compromised by the effect of that portion of the stack that exceeds the GEP.

EPA's guidance for determining GEP stack height (Hg) (EPA, 1985) is based on the height of a nearby structure(s) measured from the ground-level elevation at the base of the stack (H) and the lesser dimension—height or projected width—of the nearby structure(s) (L) as follows:

$$Hg = H + 1.5L$$

The GEP modeling restriction is the greater of the calculated GEP stack height or 65 meters. Therefore, based on the onsite and offsite building dimensions as input into BPIP-Prime, the calculated GEP height for each exhaust stack is the greater of 65 meters or the calculated height of 75.6 meters. The proposed turbine stack height of 42.67 meters (140 feet) does not exceed GEP stack height.

Ozone Limiting. One-hour NO_2 impacts during proposed project operation were modeled using the Ozone Limiting Method (OLM) (Cole and Summerhays, 1979), implemented through the "OLMGROUP ALL" option in AERMOD (EPA, 2011). AERMOD OLM was used to calculate the NO_2 concentration based on the OLM method and hourly ozone data. Hourly ozone data collected at the Blythe monitoring station during the years 2009-2013 were used in conjunction with OLM to calculate hourly NO_2 concentrations from hourly NOx concentrations.

Part of the NOx in the exhaust is converted to NO_2 during and immediately after combustion. The remaining percentage of the NOx emissions is assumed to be NO. For the gas turbine, the analysis was performed using the following NO_2/NOx ratios recommended by GE:

- 13% during normal operating hours
- 24% during hours in which a startup/shutdown occurs
- 24% during commissioning tests when the SCR system is not fully operational

For the auxiliary boiler, the analysis was performed using the following NO_2/NOx ratios recommended by the auxiliary boiler vendor:

- 29% for operation above 25% rated load (normal operating hours)
- 12.5% for operation below 25% rated load (during hours in which a startup/shutdown occurs)

A NO_2/NOx ratio of 20% was used for the diesel emergency firepump engine.[30]

As the exhaust leaves the stack and mixes with the ambient air, the NO reacts with ambient O_3 to form NO_2 and molecular O_2. The OLM assumes that at any given receptor location, the amount of NO that is converted to NO_2 by this oxidation reaction is proportional to the ambient O_3 concentration. If the O_3 concentration is less than the NO concentration, the amount of NO_2 formed by this reaction is limited. However, if the O_3 concentration is greater than or equal to the NO concentration, all of the NO is assumed to be converted to NO_2.

Annual NO_2 concentrations were calculated using the Ambient Ratio Method (ARM), originally adopted in Supplement C to the Guideline on Air Quality Models (EPA, 1995) with a revision issued by EPA in March 2011 (EPA, 2011). The Guideline allows a nationwide default of 75% for the conversion of NO to NO_2 on an annual basis and the calculation of NO_2/NOx (nitrogen oxide) ratios. This nationwide default conversion factor was used to model annual NO_2 impacts for the proposed project.

3.1.5.2 Construction Impacts Analysis

As previously discussed, the construction activities will occur for approximately 26 months (including 4 months of commissioning) and various stages of construction will overlap throughout this period. To evaluate the overall potential air quality impacts from construction activities, the schedules for each activity were aligned and the maximum daily, monthly, and annual rolling 12-month emissions were developed. A complete summary of emissions during construction is provided in Appendix 3.1C. Because the adjacent BEP will operate during the SEP construction period, the construction impacts modeling analysis contains BEP.

The CEC requires an assessment of the potential ambient air quality impacts of construction activities. Emissions during the construction period were calculated on a maximum hourly, daily, monthly, and annual rolling 12-month basis. Modeled concentrations of NOx, CO, PM_{10}, $PM_{2.5}$, and SOx from onsite construction activities were combined with the ambient background concentrations and compared to the AAQS. The exhaust emissions and mechanically generated fugitive dust emissions (e.g., dust from wheels of a scraper) were modeled as volume sources with heights of 6 meters and 3 meters, respectively. Wind-blown fugitive dust emissions and sources at or near the ground that are at ambient temperature and have negligible vertical velocity were modeled as a ground-level area source with an initial vertical dimension of 1 meter. The maximum 1-hour NO_2 concentrations were modeled using the OLM approach described above, with initial NO_2/NOx ratios of 11% based on CAPCOA recommendations for heavy-duty diesel trucks (CAPCOA, 2011). The results of the construction modeling analysis are summarized in Table 3.1-37. A detailed summary of the assumptions and emission factors used to estimate the emission rates is presented in Appendix 3.1C.

[30] CAPCOA, “Modeling Compliance of The Federal 1-Hour NO_2 NAAQS,” October 27, 2011. Appendix C, Default Recommended In-Stack NO2/NOx Ratios for Diesel-fueled IC Engines.

Table 3.1-37. Maximum Modeled Impacts During Project Construction

Pollutant	Averaging Period	Maximum Modeled Concentration During SEP Construction ($\mu g/m^3$)	Modeled Concentration, BEP[a] ($\mu g/m^3$)	Combined Concentration, SEP + BEP ($\mu g/m^3$)[b]
NO_2[c]	1-hour[d]	130.7	4.8	130.7
	Annual	3.6	0.1	3.6
SO_2	1-hour[d]	1.9	0.8	1.9
	3-hour	1.6	0.7	1.6
	24-hour	0.35	0.25	0.44
CO	1-hour	1,009.2	5.1	1,009.2
	8-hour	504.6	2.1	504.6
PM_{10}	24-hour	17.1	0.8	17.2
	Annual	1.3	0.1	1.4
$PM_{2.5}$	24-hour (98th percentile)	2.8	0.8	2.8
	Annual	0.2	0.1	0.3

Notes:

[a] Modeled concentrations at location of maximum modeled concentration during SEP construction.

[b] Combined concentration does not necessarily equal the sum of the individual concentrations because the individual maxima may occur during different hours at the same receptor.

[c] The maximum 1-hour NO_2 concentration is based on OLM, and the maximum annual NO_2 concentration shows an NO_2 to NOx equilibrium ratio of 0.75.

[d] Only highest first high is shown, for comparison with state standard. Federal standard is based on a 3-hour average, and construction period will last for less than 2 years.

3.1.5.3 Operational Impacts

Screening Procedures and Unit Impact Modeling. Turbine emissions and stack parameters, such as flow rate and exit temperature, vary with ambient temperature and operating load. Therefore, to evaluate the worst-case air quality impacts for the new gas turbine, an initial screening-level dispersion modeling analysis was conducted to select the worst-case gas turbine operating mode for each pollutant and averaging period. The modeling used emissions data based on maximum temperature (110°F), annual average temperature (74°F), ISO temperature (59°F), and minimum temperature (39°F), and at nominal minimum and maximum gas turbine operating load points.[31] The determination of the worst-case gas turbine operating condition depends on how changes in emissions rates and stack characteristics (plume rise characteristics) interact with terrain features. For example, lower mass emissions resulting from lower load operation may cause higher concentrations than other operating conditions because lower final plume height may have a greater significant interaction with terrain features.

Initial AERMOD modeling runs were performed using normalized emission rates to assess the zone of impact and relative magnitude of the impacts. For the AERMOD gas turbine screening modeling, the gas turbine was modeled with a unit emission rate of 1 gram per second to obtain maximum 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentration to emission rate (χ/Q in units of $\mu g/m^3$ per g/s) values. These χ/Q values were multiplied by the actual emission rate in grams per second from the gas

[31] Minimum gas turbine load ranges from 40 to 65 percent, depending upon ambient conditions.

turbine to calculate ambient impacts for NO_2, CO, SO_2, and $PM_{10}/PM_{2.5}$ in units of $\mu g/m^3$. Stack parameters used in the screening modeling analysis are shown in Appendix 3.1F.

The results of the screening analysis are shown in Appendix 3.1F, Table 3.1F-2. The stack parameters and emission rates corresponding to the operating case that produced the maximum impacts in the gas turbine screening analysis for each pollutant and averaging period were used in the refined modeling analysis to evaluate air quality impacts.

Refined Air Quality Impact Analysis. In simple, intermediate, and complex terrain, AERMOD was used to estimate proposed project impacts. The AERMOD model was used to calculate 1-hour, 3-hour, 8-hour, 24-hour, and annual average concentrations.

Refined modeling was performed in two phases: coarse grid modeling and fine grid modeling. Preliminary modeling was performed with the coarse grid to locate the areas of maximum concentration; fine grids were used to refine the location of the maximum concentrations.

The stack parameters and emission rates used to model combined impacts from all new equipment at the facility are shown in Appendix 3.1F. The model receptor grids were derived from U.S. Geological Survey (USGS) 10-meter Digitized Elevation Map (DEM) data. CEC guidance was used to locate receptors. Offsite receptor locations were discussed above in Section 3.1.5.1. Concentrations within the facility fenceline were not calculated.[32]

Terrain features were taken from the USGS National Elevation Dataset (NED). These terrain data are part of the modeling DVD submitted to the MDAQMD and CEC as part of the PTA for the proposed project.

Commissioning Impacts Analysis. During the initial commissioning period, the turbine will initially be operated at various load rates without the benefit of the emission control systems to ensure proper operation. In addition, steam from the auxiliary boiler will be needed during gas turbine commissioning activities, so the auxiliary boiler will be commissioned first. The commissioning impact analysis was made conservatively overpredictive by assuming for the dispersion modeling analysis that simultaneous commissioning of the two units (boiler and turbine) will occur. It was also assumed that the maximum impact will occur if both units were simultaneously undergoing commissioning activities while the gas turbine exhibited its highest unabated emissions (e.g., steam blows for NOx and first synchronization for CO). Therefore, the AERMOD coarse and refined grid dispersion analyses were conducted using the parameters and emission rates presented in Table 3.1-24. It is assumed that the maximum modeled impacts during commissioning will occur under the gas turbine operating conditions that are least favorable for dispersion. These conditions are expected to occur under low-load conditions.

Air quality impacts during the commissioning period were determined using the emission rates in Table 3.1B-7. One-hour average NO_2 impacts during commissioning were modeled using AERMOD with OLM and concurrent Blythe ozone data. Modeled impacts are shown in Table 3.1-38. SOx and $PM_{10}/PM_{2.5}$ emissions during the commissioning of the gas turbine are not expected to be higher than during normal operation of these units.

As discussed above, the existing BEP was also modeled to ensure that impacts of those generating units were reflected in background concentrations. Therefore, the commissioning modeling analysis analyzed the combined impacts for the simultaneous commissioning of SEP and the continued operation of the existing BEP. Emissions from the existing BEP gas turbines were adjusted for this analysis to reflect the proposed new hourly and annual limits discussed in Section 3.1.4.8.

[32] Because BEP and SEP have a common owner and are adjacent sites, locations within either the BEP or SEP facility fencelines were not considered ambient air.

Table 3.1-38. Maximum Modeled Impacts for the Commissioning Period

Pollutant	Averaging Period	Modeled Impact, SEP, µg/m³	Monitored Background Concentration, µg/m³	Modeled Impact, BEP, µg/m³	Total Impact, µg/m³	Most Stringent Standard, µg/m³	Percent of Most Stringent Standard
NO_2	1 hour[a]	178.1	77.1	12.73	231.9	339	68%
CO	1 hour	4,265.7	4,000	26.70	8,288	23,000	36%
	8 hours	960.9	1,698	7.15	2,661	10,000	27%

[a] Based on AERMOD-OLM.

The analysis excluded a comparison to the federal 1-hour NO_2 standard because the maximum hourly unabated emission rates that result in the highest predicted concentrations are expected to occur only once in the life of the project and that one time will be less than 120 hours. Furthermore, the federal 1-hour NO_2 standard is based on a 98th percentile statistical standard, so it is unlikely that simultaneous one-time unabated emissions for the gas turbine and auxiliary boiler will occur on the days with the highest background NO_2 and ozone concentrations.[33]

Fumigation Impacts. Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may cause high ground-level pollutant concentrations because the plume is unable to rise upwards normally because of the stable layer capping it from above, and be drawn to the ground by turbulence within the unstable layer. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time. For this analysis, fumigation was assumed to occur for up to 90 minutes, as recommended by EPA guidance.

The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Guidance from the EPA (EPA, 1992) was followed in evaluating fumigation impacts. This analysis is shown in more detail in Appendix 3.1F. Fumigation modeling results are summarized in Table 3.1-39.

Impacts During Gas Turbine Startup. Facility impacts were also evaluated during startup of the new gas turbine to evaluate short-term impacts under worst-case startup emissions. Gas turbine exhaust parameters used to characterize gas turbine exhaust during startup and the CO and NO_x emission rates are shown in Appendix 3.1F. Impacts during gas turbine startup are shown in Table 3.1-39.

Air Quality Modeling Results. The 1-hour NOx and CO emission rates were based on the conservative assumption that the gas turbine will be in cold startup mode and the auxiliary boiler will be operational within the same hour. The emission rates for 8-hour and 24-hour averaging periods was based on the assumption that the gas turbine and auxiliary boiler will both undergo a cold startup and a shutdown during the period, and will operate for the remaining hours at 100 percent load. The hourly emission rates for 24-hour PM_{10} and $PM_{2.5}$ were based on operation at 100 percent load.

As discussed previously, annualized hourly emission rates for the annual impact assessment were based on 7,000 hours per year of plant operation, which encompasses 5,500 hours per year of turbine operation without duct firing and 1,500 hours per year with duct firing; 400 hours in startup/shutdown mode (50 cold starts, 150 warm starts, and 200 shutdowns); 7,000 hours per year of auxiliary boiler

[33] Although EPA is not the reviewing authority for this permit, we note that excluding this short-term, one-time emissions scenario is consistent with EPA's March 1, 2011, guidance (EPA, 2011): "When EPA is the reviewing authority for a permit… we will consider it acceptable to limit the emission scenarios included in the modeling compliance demonstration for the 1-hour NO_2 NAAQS to those emissions that are continuous enough or frequent enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations."

operation; 8,760 hours per year of cooling tower operation; and 200 hours per year of emergency fire pump engine operation.

The facility layout for modeling is shown in Appendix 3.1F.

Table 3.1-39 summarizes the maximum impacts during the operation of the proposed project, calculated from the refined, startup/shutdown, and fumigation modeling analyses described above. These impacts reflect only operation of the proposed new equipment.

The maximum impacts for normal facility operating conditions (with fire pump and auxiliary boiler emission) for NO_2 (1-hour and annual averages), CO (1-hour and 8-hour averages), SO_2 (annual averages), and PM_{10}/$PM_{2.5}$ (24-hour and annual averages) occurred in the immediate vicinity of the facility either on the southern fenceline or within the downwash grid in the 30-meter-spaced receptor areas. Maximum impacts for start-up/shutdown conditions (1-hour NO_2 and CO impacts and 8-hour CO impacts) and 1-hour and 3-hour SO_2 impacts during normal facility operation occurred in elevated terrain about 8.5 km west-northwest of the project while maximum 24-hour SO_2 impacts occurred about 760 meters south of the project.

Table 3.1-39. Air Quality Modeling Results

		Modeled Maximum Concentrations (µg/m³)		
Pollutant	**Averaging Time**	**Normal Operation AERMOD**	**Startup/Shutdown AERMOD**	**Fumigation SCREEN3**
Gas Turbine				
NO_2[g]	1-hour	11.55	101.58	3.87
	98th percentile	6.00	53.74	-
	Annual	0.17	a	c
SO_2	1-hour	2.89	b	0.73
	3-hour	1.49	b	0.60
	24-hour	0.39	b	0.25
	Annual	0.02	b	c
CO	1-hour	9.23	117.89	2.36
	8-hour	7.90	a	1.42
$PM_{2.5}$/PM_{10}	24-hour	1.14	b	0.56
	Annual	0.06	b	c
Auxiliary Boiler				
NO_2	1-hour	1.08	8.37	0.88
	98th percentile	0.99	7.47	-
	Annual	0.05	a	c
SO_2	1-hour	0.23	b	0.14
	3-hour	0.18	b	0.12
	24-hour	0.12	b	0.05
	Annual	0.004	b	c
CO	1-hour	6.21	63.04	3.84
	8-hour	9.18	a	2.38
$PM_{2.5}$/PM_{10}	24-hour	0.54	b	0.25
	Annual	0.04	b	c
Emergency Diesel Fire Pump Engine				
NO_2	1-hour	59.3	d	e
	98th percentile	51.4	d	-
	Annual	0.04	d	c,e

Table 3.1-39. Air Quality Modeling Results

Pollutant	Averaging Time	Modeled Maximum Concentrations (µg/m³)		
		Normal Operation AERMOD	**Startup/Shutdown AERMOD**	**Fumigation SCREEN3**
SO_2	1-hour	0.1	d	e
	3-hour	0.02	d	e
	24-hour	0.005	d	e
	Annual	<0.001	d	c,e
CO	1-hour	15.8	d	e
	8-hour	0.5	d	e
$PM_{2.5}/PM_{10}$	24-hour	0.02	d	0.3
	Annual	0.001	d	c
Cooling Tower				
$PM_{2.5}/PM_{10}$	24-hour	4.9	d	e
	Annual	0.4	d	c,e
Combined Impacts, All SEP Equipment				
NO_2[g]	1-hour	59.3	101.6	3.9
	98th percentile	51.4	53.8	-
	Annual	0.2	a	c
SO_2	1-hour	2.9	b	0.7
	3-hour	1.5	b	0.6
	24-hour	0.4	b	0.2
	Annual	0.02	b	c
CO	1-hour	15.8	117.9	2.4
	8-hour	9.2	a	1.4
$PM_{2.5}/PM_{10}$ f	24-hour	5.3	b	0.6
	Annual	0.5	b	c

[a] Not applicable, because startup/shutdown emissions are shown in the modeling for this averaging period.

[b] Not applicable, because emissions are not elevated above normal operation levels during startups/shutdowns.

[c] Not applicable, because inversion breakup is a short-term phenomenon and as such is evaluated only for short-term averaging periods.

[d] Not applicable, because engine emissions are the same during gas turbine startups/shutdowns.

[e] Not applicable, this type of modeling is not performed for small combustion sources with relatively short stacks.

[f] Encompasses cooling tower.

[g] 1-hour NO_2 modeled using OLM. Annual NO_2 modeled using ARM.

3.1.5.4 Modeling Results Compared to the Ambient Air Quality Standards

To determine a project's air quality impacts, the modeled concentrations are added to the maximum background ambient air concentrations and then compared to the applicable ambient air quality standards. As discussed above, the existing BEP generating units were modeled along with impacts from the proposed SEP and total impacts were then added to the monitored background concentrations from Table 3.1-11 to evaluate total impacts.

Construction Impacts Analysis. The results presented in Table 3.1-40 indicate that the maximum NO_2, CO and SOx construction impacts combined with the background concentrations will be below the AAQS for each averaging period.[34] For particulate, the annual and 24-hour PM_{10} background concentrations exceed the state AAQS without adding the modeled concentrations. As a result, the predicted impacts will also be greater than the AAQS. Based on the modeling analysis, fugitive dust is a significant contribution to the predicted concentrations but the maximum PM_{10} and $PM_{2.5}$ concentrations will remain near the property boundary. The implementation of the construction mitigation measures presented in Section 3.1.8.1 are expected to reduce the offsite construction air quality impacts to less-than-significant levels.

Table 3.1-40. Maximum Modeled Impacts from Construction and the Ambient Air Quality Standards

Pollutant	**Averaging Period**	**Maximum Modeled Concentration[a] (µg/m³)**	**Background Concentration[b] (µg/m³)**	**Total Predicted Concentration (µg/m³)**	**State Standard (µg/m³)**	**Federal Standard (µg/m³)**
NO_2	1-hour[c]	130.7	77.1	196.2	339	—
	Annual	3.6	13.2	16.8	57	100
SO_2	1-hour[c]	1.9	22.9	24.8	655	—
	3-hour	1.6	22.6	24.2	—	1,300
	24-hour	0.4	2.6	3.0	105	365
CO	1-hour	1,009.2	4,000	5,009.2	23,000	40,000
	8-hour	504.6	1,698	2,202.6	10,000	10,000
PM_{10}	24-hour	17.2	127	144.2	50	150
	Annual	1.4	22.1	23.5	20	—
$PM_{2.5}$	24-hour (98th percentile)	2.8	13.8	16.6	—	35
	Annual	0.3	6.5	6.8	12	15

[a] Includes BEP. See Table 3.1-37.

[b] Background concentrations were the highest concentrations monitored between 2012 and 2014. See Table 3.1-11.

[b] The maximum 1-hour NO_2 concentration is based on OLM, and the maximum annual NO_2 concentration shows an NO_2 to NOx equilibrium ratio of 0.75.

[c] Only highest first high is shown, for comparison with state standard. Federal standard is based on a 3-hour average, and construction period will last for less than 2 years.

Operation Impacts Analysis. The highest modeled concentrations were used to demonstrate compliance with the AAQS. Table 3.1-41 presents a comparison of the maximum operational impacts to the AAQS. This assessment contains modeled impacts from the existing BEP, which is likely to have localized impacts that are not captured in the monitored background data. The NO_2, CO, SO_2, and $PM_{2.5}$ concentrations combined with the background concentrations do not exceed the AAQS. Therefore, the proposed project will not cause or contribute to the violation of a standard, and the NO_2, CO, SO_2, and $PM_{2.5}$ impacts from operation will be less than significant.

For PM_{10}, the background concentrations exceed the AAQS without the proposed project, with the exception of the federal 24-hour standard. As a result, the predicted project impact plus background also exceeds the state PM_{10} standards and the operation of the proposed project could further contribute to an existing violation of the state standards absent mitigation. As discussed in Section 3.1.8.2, project emissions will be fully offset consistent with MDAQMD Rule 1303. Therefore, the PM_{10} impacts from project operation will be less than significant.

[34] Impacts during the SEP construction period reflect operation of the BEP, as the BEP is expected to be operating while SEP is under construction.

Table 3.1-41. Operation Impacts Analysis—Maximum Modeled Impacts Compared to the Ambient Air Quality Standards

Pollutant	Averaging Time	Maximum Modeled Concentration ($\mu g/m^3$)[a]	Modeled Impact, BEP ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)[b]	Total Combined Predicted Concentration ($\mu g/m^3$)	State Standard ($\mu g/m^3$)	Federal Standard ($\mu g/m^3$)
NO_2[c]	1-hour	101.6	21.4	77.1	167	339	—
	Federal 1-hour[d]	53.8	11.1	77.1	115	—	188
	annual	0.2	0.2	13.2	14	57	100
SO_2	1-hour	2.9	4.1	22.9	30	655	—
	Federal 1-hour[e]	2.9	4.1	13	20	—	196
	3-hour	1.5	1.9	22.6	26	—	1,300
	24-hour	0.4	0.64	2.6	3.4	105	365
CO	1-hour	117.9	26.7	4,000	4,141	23,000	40,000
	8-hour	9.2	7.2	1,698	1,711	10,000	10,000
PM_{10}	24-hour	5.3	2.8	127	132	50	150
	Annual	0.5	0.4	22.1	23	20	—
$PM_{2.5}$	24-hour[d]	5.3	2.8	13.8	19	—	35
	Annual	0.5	0.4	6.5	7.2	12	15

[a] SEP only.

[b] Background concentrations were the highest concentrations monitored during 2011--2013.

[c] The maximum 1-hour NO_2 concentration is modeled using AERMOD OLM, and the maximum annual NO_2 concentration uses the ambient ratio method (ARM) with the default NO_2 to NOx equilibrium ratio of 0.75.

[d] Total predicted concentrations for the federal 1-hour NO_2 standard and 24-hour $PM_{2.5}$ standard are the respective maximum modeled concentrations combined with the three-year average of 98th percentile background concentrations.

[e] Total predicted concentrations for the federal 1-hour SO_2 standard is the maximum modeled concentrations combined with the 3-year average of 99th percentile background concentrations.

PSD Significance Levels. The PSD program was established to allow emission increases that do not result in significant deterioration of ambient air quality in areas where criteria pollutants have not exceeded the NAAQS. Although the proposed project will not be subject to PSD review, the PSD significant impact levels (SILS) can be used as one measure of whether the project's impacts are significant.

The comparison in Table 3.1-42 shows that project impacts are below the PSD SILs for all pollutants and averaging periods except 1-hour NO_2 and 24-hour and annual $PM_{2.5}$. As discussed in Section 3.1.8.2, project emissions for these pollutants will be fully offset consistent with MDAQMD Rule 1303. Therefore, the NO_2 and $PM_{2.5}$ impacts from project operation will be less than significant.

Table 3.1-42. Comparison of Maximum Modeled Impacts and PSD Significant Impact Levels, SEP

Pollutant	Averaging Time	Significant Impact Level, $\mu g/m^3$	Maximum Modeled Concentrations for SEP, $\mu g/m^3$ [a]	Exceed Significant Impact Level?
NO_2	1-Hour	7.5[b]	101.6[c]	Yes
	Annual	1	0.2	No
SO_2	1-Hour	7.8	2.9	No
	3-Hour	25	2	No
	24-Hour	5	0.4	No
	Annual	1	0.02	No
CO	1-Hour	2000	118	No
	8-Hour	500	9	No

Table 3.1-42. Comparison of Maximum Modeled Impacts and PSD Significant Impact Levels, SEP

Pollutant	Averaging Time	Significant Impact Level, µg/m³	Maximum Modeled Concentrations for SEP, µg/m³ [a]	Exceed Significant Impact Level?
PM_{10}	24-Hour	5	5	No
	Annual	1	0.5	No
$PM_{2.5}$	24-Hour	1.2[d]	5.3	Yes
	Annual	0.3[d]	0.5	Yes

[a] Modeled concentrations have been rounded to the same number of significant figures as the SIL.

[b] EPA has not yet defined significance levels (SILs) for one-hour NO_2 and SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, interim values of 4 ppb (7.5 µg/m³) for NO_2 and 3 ppb (7.8 µg/m³) for SO_2 may be used (USEPA (2010b); USEPA (2010c)). These values will be used in this analysis as interim SILs.

[c] Concentration occurs during gas turbine startup; encompasses operation of the emergency diesel fire pump engine.

[d] While EPA sought and the U.S. Court of Appeals for the District of Columbia Circuit recently granted remand and vacatur of these SILs as they apply for purposes of avoiding a cumulative impacts analysis under federal PSD requirements (40 CFR § 51.166(k)(2) and § 52.21(k)(2)), EPA has retained these SILs for purposes of demonstrating whether a source locating in an attainment/unclassifiable area will be deemed to cause or contribute to a violation in a downwind nonattainment area. See Sierra Club v. EPA, No. 10-1413 (D.C. Cir. 2013), slip op. 9. Accordingly, application of these SILs for purposes of satisfying the District's requirement to ensure that the construction and operation of new or modified sources does not interfere with the attainment and maintenance of ambient air quality standard (MDAQMD Rule 1300) may be appropriate.

3.1.5.5 Screening Health Risk Assessment

A screening health risk assessment (SHRA) was conducted to determine expected impacts on public health of the noncriteria pollutant emissions from operation of the project. The potential health risks and a detailed discussion of the approach used for the screening level risk assessment, including the detailed noncriteria-pollutant calculations, are provided in Section 3.8, Public Health.

3.1.6 Consistency with Laws, Ordinances, Regulations, and Standards

This section considers consistency separately for federal, state, and local requirements.

3.1.6.1 Consistency with Federal Requirements

The MDAQMD has been delegated authority by the EPA to implement and enforce most federal requirements that may be applicable to the proposed project, including new source performance standards and new source review for nonattainment pollutants. The proposed project will also be required to comply with the Federal Acid Rain requirements (Title IV). Because the MDAQMD is delegated authority to implement Title IV through its Title V permit program, the Title V Federal Operating Permit that will be issued as a result of the proposed project will contain the necessary requirements for compliance with the Title IV Acid Rain provisions. In addition, the MDAQMD is in the processing of obtaining delegation from EPA to implement the PSD program. Until that delegation is in place, EPA Region 9 is the PSD permitting authority. As discussed below, the project does not trigger PSD review.

PSD Program. EPA has promulgated PSD regulations for areas that are in compliance with national ambient air quality standards (40 CFR 52.21). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., specific national parks and wilderness areas). There are five principal areas of the PSD program: (1) Applicability; (2) Best Available Control Technology; (3) Preconstruction Monitoring; (4) Increments Analysis; and (5) Air Quality Impact Analysis. Although issuance of the PSD permit will be the responsibility of either the MDAQMD or EPA

Region 9 (depending on the timing for PSD delegation to the MDAQMD), the protection of Class I areas is still the responsibility of the Federal Land Managers (FLMs).

Applicability. The federal PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing stationary source. (These terms are defined in federal regulations.) (40 CFR 52.21) Since the SEP is owned by the same parent company that owns and operates BEP, the projects are on contiguous properties and have the same SIC code, they are considered part of the same stationary source. As shown in Table 3.1-43, existing BEP is not an existing major source and SEP emissions are below major source thresholds; SEP is not a major modification to an existing major source, and SEP is not a major source itself. Consequently, the SEP is not subject to PSD review.

Table 3.1-43. Net Emission Change and PSD Applicability

Pollutant	SEP Potential to Emit (tpy)	BEP Potential to Emit (tpy)	PSD Major Source Thresholds (tpy)	Major Source/Major Modification?
NOx	85.6	97	100	No
SO_2	8.8	24	100	No
VOC	24.2	24	100	No
CO	78.0	97	100	No
PM_{10}	40.1	97[a]	100	No
$PM_{2.5}$	40.1	97[a]	100	No

Note:

[a] PM_{10}/$PM_{2.5}$ PTEs shown do not reflect the reductions proposed as part of this project.

Title V Operating Permits. MDAQMD Regulation XII implements the Title V federal operating permit program. An application for a Title V permit for the new equipment will be submitted prior to the initial operation of the new equipment in accordance with the requirements of Rule 1205 for Title V sources.

40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines). This new source performance standard applies to gas turbines with heat inputs in excess of 1 MMBtu/hr that commence construction after February 18, 2005, and therefore is applicable to the SEP CTG. Subpart KKKK limits NOx and SO_2 emissions from a new gas turbine with a heat input greater than 850 MMBtu/hr to limits of 15 ppmv @ 15% O_2 (ppmc) for NOx and 0.90 lbs/MW-hr for SOx. As shown in Table 3.1-44, the proposed CTG at SEP will comply with these limits.

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the SEP CTG will be equipped with a NOx continuous emissions monitoring system (CEMS) that will comply with NSPS requirements, the initial performance test will be met as part of the initial NOx CEMS certification testing process and ongoing annual performance testing will not be required under the NSPS.

Table 3.1-44. Compliance with 40 CFR 60 Subpart KKKK

	Project Emission Levels			
Pollutant	ppmc	lb/hr	lb/MW-hr	Subpart KKKK Limits
NOx	2.0	N/A	N/A	15 ppmc
SOx	N/A	4.9	0.0090	0.90 lb/MW-hr

40 CFR Part 60, Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). The new emergency diesel fire pump engine will be subject to this NSPS. For emergency fire pump engines in this size range, the NSPS requires manufacturers to provide engines that are certified to meet the NSPS emission standards (depending on the year an engine is manufactured). The SEP will comply with the emission limitations of the NSPS by purchasing an engine certified to EPA Tier 3 standards for nonroad diesel engines.

The NSPS also requires engines in this size range to use fuel with a sulfur content not to exceed 15 ppm. The new emergency diesel fire pump engine will comply with this requirement by using only ARB diesel fuel.

National Emission Standards for Hazardous Air Pollutants (NESHAP). This program establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution, but for which NAAQS have not been established) from major sources of HAPs in specific source categories. These standards are implemented at the local level with federal oversight. Only the NESHAPs for gas turbines (40 CFR 63 Subpart YYYY), which limit formaldehyde emissions from a CTG, are potentially applicable to the proposed project. As shown in Section 3.1.4.5, BEP and SEP will be a major source of HAPs (i.e., 10 tpy of one HAP or 25 tpy of all HAPs). However, as noted in Section 3.1.3.1, in 2004, EPA stayed the effectiveness of the NESHAP for new lean premix and diffusion flame gas-fired gas turbines. Therefore, the NESHAP does not apply to the proposed project.

3.1.6.2 Consistency with State Requirements

As discussed in Section 3.1.3.2, state law established local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. The proposed project is under the local jurisdiction of the MDAQMD; therefore, compliance with District regulations will assure compliance with state air quality requirements.

California Clean Air Act. AB 2595, the California Clean Air Act (CAA), was enacted by the California Legislature and became law in January 1989. The CAA requires the local air pollution control districts to attain and maintain both the federal and state ambient air quality standards at the “earliest practicable date.” The CAA contains several milestones for local districts and ARB. MDAQMD was required to submit an air quality plan to ARB, with updates as necessary, defining the program for meeting the required emission reduction milestones in the Mojave Desert.

Air quality plans must demonstrate attainment of the state ambient air quality standards and must result in a five percent annual reduction in emissions of nonattainment pollutants (ozone, PM_{10}, $PM_{2.5}$, and associated precursors) in a given district (H&SC §40914). A local district may adopt additional stationary source control measures or transportation control measures, revise existing source-specific or new source review rules, or expand its vehicle inspection and maintenance program (H&SC §40918) as part of the plan. District air quality plans specify the development and adoption of more stringent regulations to achieve the requirements of the Act. The applicable regulations that will apply to SEP are shown in the discussion of District prohibitory rules in Section 3.1.3.3.

Greenhouse Gas Initiatives. In 2006, California enacted the California Global Warming Solutions Act of 2006 (AB 32). It requires ARB to adopt standards that will reduce statewide GHG emissions to statewide GHG emissions levels in 1990, with such reductions to be achieved by 2020. To achieve this, ARB has a mandate to define the 1990 emissions level and achieve the maximum technologically feasible and cost-effective GHG emission reductions.

ARB adopted early action GHG reduction measures in October 2007 and established statewide emissions caps by economic “sectors” in 2008. In December 2008, ARB adopted a scoping plan that identifies how emission reductions will be achieved from significant sources of GHG via regulations, market mechanisms, and other actions. ARB staff has developed regulations to implement its plan.

Among the applicable GHG requirements is the submittal of annual GHG emission reports to ARB for subject facilities, which must contain the project's emission rates of greenhouse gases. The project will be required to track and report GHG emissions from the gas turbine and auxiliary equipment, fuels and materials handling processes, and delivery and storage systems, as well as from all on-site secondary emission sources. The facility will also be required to participate in the cap and trade program.

SB 1368, also enacted in 2006, and regulations adopted by the CEC and the Public Utilities Commission pursuant to the bill, prohibits utilities from entering into long-term commitments with any baseload facilities that exceed the Emission Performance Standard of 0.50 metric tons of CO_2 per MW-hour (1,100 pounds CO_2/MWh). Specifically, the Emission Performance Standard (EPS) applies to base load power from new power plants, new investments in existing power plants, and new or renewed contracts with terms of five years or more, including contracts with power plants located outside of California. Compliance with the EPS is discussed further below.

GHG Emissions During Project Construction. Construction of the proposed power plant will involve the use of fuel-consuming equipment for construction and transportation and will produce greenhouse gas emissions. GHG emissions during construction are provided in Appendix 3.1C.

These small GHG emissions increases from construction activities will not be significant. The construction period is about 26 months long (including 4 months of commissioning), and the emissions will be intermittent during that period. Additionally, the mitigation measures proposed by the project owner (such as limiting idling times) will minimize GHG emissions during the construction phase of the project.

GHG Emissions During Project Operation. In the absence of established thresholds of significance or methodologies for assessing impacts, this analysis of GHG emission impacts consists of quantifying project-related GHG emissions, determining their significance in comparison to the goals of AB 32, and discussing the potential impacts of climate change within the state as well as strategies for minimizing those impacts.

As the CEC's 2007 Integrated Energy Policy Report (CEC, 2007) noted:

> New natural gas-fueled electricity generation technologies offer efficiency, environmental, and other benefits to California, specifically by reducing the amount of natural gas used—and with less natural gas burned, fewer greenhouse gas emissions. Older combustion and steam turbines use outdated technology that makes them less fuel- and cost-efficient than newer, cleaner plants… The 2003 and 2005 IEPRs noted that the state could help reduce natural gas consumption for electric generation by taking steps to retire older, less efficient natural gas power plants and replace or repower them with new, more efficient power plants. (p. 184)

The California Public Utilities Commission (CPUC) and CEC joint recommendations to ARB state that renewable integration will be a "cornerstone" of emission reductions.[35] Similarly, the ARB AB 32 scoping plan anticipates the implementation of a 33% Renewable Portfolio Standard (RPS) and contains the RPS as an emission reduction measure.[36] The current RPS requires all the state's energy service providers meet 33 percent of retail sales with renewable energy by 2020. Recently, the Governor has announced plans to seek an increase in the state's RPS target to 50% by 2030.

Most renewable energy facilities, such as those using wind or solar energy, are "intermittent resources," meaning these resources are not available to generate in all hours and thus have limited operating

[35] See: CPUC and CEC, D.06-04-009, CEC-100-2008-007-F, *Final Opinion and Recommendations on Greenhouse Gas Regulatory Strategies* Joint Recommendations to ARB (October 2008) p.1, available at: http://www.energy.ca.gov/2008publications/CEC-100-2008-007/CEC-100-2008-007-F.PDF

[36] See: California Air Resources Board, Final AB 32 Scoping Plan (Dec. 2008), available at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm

capacity. For example, intermittent resources can be limited by meteorological conditions on an hourly, daily, and seasonal basis. Further, most renewable resources have no ability to provide regulation—the ability to ramp up and down quickly at the system operator's direction to ensure electric system reliability. In addition, the availability of intermittent resources is often unrelated to the load profile they serve. For example, some photovoltaic resources reach peak production around 12:00 noon while the demand on California's electric system typically peaks between 5:00 p.m. and 7:00 p.m.

SEP can be operated without the limitations affecting intermittent renewable resources. The SEP gas turbine will be an efficient, fast-starting, flexible generating resource that will allow SEP to support generation from intermittent renewable resources and thus integrate renewable resources into California's generating system without affecting electric system reliability.

Much of the electricity generated by SEP is expected to be used to replace electricity currently generated by coal plants in the southwest, as coal contracts expire and cannot be renewed. As a highly efficient fast starting, and dispatchable generating resource, SEP may also replace generation from older, less efficient gas plants. SEP will also help provide "firming" sources for existing and future intermittent renewable resources in support of RPS and GHG goals. "Firming" involves the use of fast-starting, flexible generation that is always available under all operating conditions to ramp up or ramp down, as necessary, to balance load and generation. Firming power is the cornerstone of system reliability. Thus, in the context of the California Environmental Quality Act, the CEC's Integrated Energy Policy Report, and other state GHG policy documents, the SEP will not be expected to cause a significant cumulative impact. Instead, SEP supports the State's strategy to reduce overall fuel use and GHG emissions. Furthermore, even though it is possible to quantify how many gross GHG emissions are attributable to a project, it is difficult to determine whether this will result in a net increase of these emissions, and, if so, by how much. Therefore, it would be speculative to conclude that any given project results in a cumulatively significant adverse impact from GHG emissions.

The GHG CEQA Guidance encompasses the following elements:

- Quantification of GHG emissions
- Determination of whether the project may increase or decrease GHG emissions as compared to existing environmental setting
- Determination of whether the project emissions exceed a threshold of significance determined by the lead agency
- The extent to which the project complies with state, regional, or local plans for reduction or mitigation of GHGs
- Mitigation measures

Certain GHG reduction strategies will require increases in natural gas consumption; for example, some fraction of electric generation from coal-fired power plants will need to be replaced by natural gas fired generation. As the 2007 Integrated Energy Policy Report (CEC, 2007) and Presiding Member's Proposed Decision for the Avenal Energy Project (CEC, March 2009a) acknowledged, "new gas-fired power plants are more efficient than older power plants, and they displace these older facilities in the dispatch order." The CEC's 2009 Framework report (CEC, May 2009b) further discussed the role of new gas-fired power plants in displacing GHG emissions, and furthering the State's efforts to reduce GHG emissions. The 2009 Framework report concludes that as California expands renewable energy generation to achieve its GHG emissions reduction goals, it cannot simply retire natural-gas fired power plants: rather, new natural-gas fired power plants may be needed. Net GHG emissions for the integrated electric system will decline when new gas-fired power plants are added that (1) serve load growth or capacity needs more efficiently than the existing fleet; (2) improve the overall efficiency of the electric system; and/or (3) permit increased penetration of renewable generation (CEC, May 2009). Because of its location and operational characteristics, SEP will contribute to the reduction of GHG emissions because it will achieve all of these goals.

In the 2009 CEC Siting Committee Report (CEC 2009a), the Committee established a three-part test to ensure that new natural gas fired power plants approved by the CEC will support the goals and policies of AB 32 and the related parts of California's GHG framework. The elements of this test are listed below.

(1) The project must not increase the overall system heat rate for natural gas plants.

(2) The project must not interfere with generation from existing renewable facilities nor with the integration of new renewable generation.

(3) Taking into account the factors listed in (1) and (2), the project must reduce system-wide GHG emissions and support the goals and policies of AB 32.

As a fast-starting, fast-ramping and highly efficient facility, SEP will meet all three of these criteria. Because electricity generation and demand must be in balance at all times, the energy provided by a new generating resource must simultaneously displace the same amount of energy from an existing resource. The electricity from the new generating resource will only be dispatched if it were less expensive to operate, which will occur when the new generating resource is more efficient than the existing resource. By definition, then the new resource will produce fewer GHG emissions than the resource it is replacing.[37]

Table 3.1-45 summarizes the thermal efficiency of many of the natural gas-fired combined cycle projects built in California over the past 15 years. The proposed SEP has the best thermal efficiency of any of the projects listed here.

The Rapid Response gas turbine will be capable of starting up and reaching full gas turbine load (330 MW) within 30 minutes. The SEP gas turbine will also have a very high ramp rate (up to 15 percent per minute, or 50 MW/minute).

The proposed SEP gas turbine will have an overall gross heat rate of approximately 6583 Btu/kWh (HHV, gross), which leads to an estimated GHG emission rate of 0.35 MT CO2/MWh (gross). This emission rate is well below the EPS of 0.50 MT CO2/MWh. The project's capability for fast response will provide firming capability that will support the integration of new renewable generation. By displacing older, less efficient units, the project will reduce system-wide GHG emissions.

3.1.6.3 Consistency with Local Requirements: MDAQMD

The MDAQMD has been delegated responsibility for implementing local, state, and federal air quality regulations in the Mojave Desert Air Basin. The proposed project is subject to District regulations that apply to new stationary sources, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from noncriteria pollutants. Facility compliance with applicable District requirements is evaluated below.

Table 3.1-45. Comparison of Heat Rates for Combined Cycle Plants in California

Plant Name	Capacity (MW)[a]	Year Licensed[a]	Heat Rate (Btu/kWh)[b]
Los Medanos Energy Center	555	1999	7,484
Sutter Energy Center	540	1999	7,600
Delta Energy Center	887	2000	7,463

[37] CEC, 2015, Appendix AQ-1.

Table 3.1-45. Comparison of Heat Rates for Combined Cycle Plants in California

Plant Name	Capacity (MW)[a]	Year Licensed[a]	Heat Rate (Btu/kWh)[b]
Moss Landing Power Plant	1,060	2000	7,252
Pastoria Energy Facility	750	2000	7,039
Blythe Energy Project	520	2001	7,089
Gateway Generating Station	530	2001	7,247
Metcalf Energy Center	600	2001	7,419
Otay Mesa Energy Center	590	2001	7,217
Inland Empire Energy Center	800	2003	6,967
Palomar Energy Center	546	2004	6,992
Walnut Energy Center	250	2004	7,796
Russell City	600	2007	7,215
Colusa Generation Station	660	2008	7,166
GWF Tracy Combined Cycle	145	2010	8,056[c]
NCPA Lodi Energy Center	255	2010	7,059
NRG El Segundo Units 5, 6, 7 and 8	560	2010	7,331[c]
Oakley Generating Station	624	2011	6,779[c]
Sonoran Energy Project	**544**	**tbd**	**6,583[d]**

[a] Source: CEC Status of All Projects, http://www.energy.ca.gov/sitingcases/all_projects.html
[b] Source: QFER CEC-1304 Power Plant Reporting Database, data for 2014.
[c] CEC Final Staff Assessments.
[d] Includes startup and shutdown in heat rate calculation.

New Source Review Requirements. Under the regulations that govern new sources of emissions, the proposed project is required to secure a preconstruction Determination of Compliance from the MDAQMD, as well as demonstrate continued compliance with regulatory limits when the new equipment becomes operational. The preconstruction review demonstrates that subject new equipment will use BACT, will provide any necessary emission offsets, and will perform an ambient air quality impact analysis. The requirements of each of these elements of the MDAQMD's new source review program are discussed below.

Best Available Control Technology. BACT must be applied to a new or modified emissions unit resulting in an emissions increase exceeding MDAQMD BACT threshold levels. In Table 3.1-46, the maximum daily emissions from the gas turbine, auxiliary boiler, cooling tower and emergency fire pump engine are compared with the BACT thresholds. As shown in this table, the CTG is subject to BACT for NOx, VOC, SOx, and PM_{10}. BACT review is also required for the cooling tower and for NOx emissions from the emergency fire pump engine. For the auxiliary boiler, emissions of all pollutants are below the applicable thresholds, so the boiler is not required to undergo BACT review.

Table 3.1-46. MDAQMD BACT Applicability

Pollutant	BACT Threshold (lbs/day)	CTG (lbs/day)	Auxiliary Boiler (lbs/day)	Firepump Engine (lbs/day)	Wet Cooling Tower (lbs/day)
PM_{10}	25	238	11.1	0.004	38.9
NOx	25	871	16.3	32.2	--
SOx	25	118	2.2	<0.1	--
VOC	25	278	7.5	0.9	--

BACT for the applicable pollutants was determined by reviewing a number of BACT guideline documents, including the BAAQMD and SJVAPCD BACT Guidance, the South Coast Air Quality Management District BACT Guideline Manual, and the EPA's RACT/BACT/LAER Clearinghouse. The detailed BACT analysis is included in Appendix 3.1D.

Emission Offsets. Emission offsets are required for increases in emissions of nonattainment pollutants that occur at the facility above MDAQMD offset threshold levels. Because the proposed SEP is considered a modification to the existing BEP, the facility emissions shown below are the sum of permitted emissions at BEP and SEP. Emission increases from the proposed project are compared with the District offset thresholds in Table 3.1-47. Under District Rule 1305(a)(2)(b)(ii)b.II, offsets must be provided for emissions that exceed the threshold amounts in Rule 1303(B).

Table 3.1-47. MDAQMD Nonattainment Pollutant Emission Offset Thresholds (tpy)

Pollutant	Existing BEP Emissions	Proposed Emissions, SEP	Net Reductions, BEP[a]	Total Facility Emissions (BEP+SEP)	Emission Offset Thresholds[b]	Net Increase	Emission Offsets Required
NOx	97	85.6	0.0	182.6	25	85.6	85.6[c]
SOx	24	8.8	-12.0	20.8	25	-3.2	0.0
VOC	24	24.3	0.0	48.3	25	24.3	23.3[d]
PM_{10}	97	40.1	-40.1	97.0	15	0	0.0

[a] Proposed reductions in permitted emissions from BEP.

[b] MDAQMD Rule 1303 (b)(1). CO offsets not required because MDAQMD is in attainment of the CO standards.

[c] Existing BEP NOx emissions were previously fully offset, so offsets are required only for the net increase from SEP.

[d] Per District Rule 1305(a)(2)(b)(ii)b.II, offsets must be provided for emissions that exceed the 25 tpy threshold amount (48.3 – 25 = 23.3 tpy of offsets required).

SEP is generating 40.1 tons of simultaneous PM_{10} reductions by reducing the permitted facility-wide PM_{10} emission limit at BEP from 97 to 56.9 tpy. These simultaneous AERs may be used as offsets for PM_{10} and PM_{10} precursors (including SOx) under District Rule 1305(B)(2). APHUS also owns 200 tons of NOx ERCs that will be used to provide the remaining required offsets. As required by District rules, these emission offsets will be surrendered to the MDAQMD prior to the initial operation of SEP.

Air Quality Impact Analysis. Under the MDAQMD new source review regulations, every project owner for a new or modified facility must demonstrate that the proposed emission increases will not interfere with the attainment or maintenance of an applicable ambient air quality standard. The modeling analyses presented in Section 3.1.5 show that the proposed project will not interfere with the attainment or maintenance of the applicable air quality standards or cause additional violations of any standards, with the exception of PM_{10}, for which the state standards are already exceeded. Offsets will be provided to ensure that potential impacts are mitigated.

3.1.7 Cumulative Impacts

The project owner requested a list of projects that are within a six-mile radius of the proposed project and are currently in the permitting process, are undergoing CEQA review, or recently received an Authority to Construct (ATC) from the MDAQMD. The District responded that while there are no projects meeting these criteria, BEP should be modeled and added to monitored background to ensure that potential local cumulative impacts are adequately evaluated. The modeling results presented in Section 3.1.5 contain BEP, as requested. Potential regional cumulative impacts are addressed further in Appendix 3.1G.

3.1.7.1 Nitrogen Deposition Analysis

Nitrogen deposition is the input of NOx and ammonia (NH_3) derived pollutants, primarily nitric acid (HNO_3), from the atmosphere to the biosphere. Nitrogen deposition can lead to adverse impacts on sensitive species, including direct toxicity, changes in species composition among native plants, and enhancement of invasive species.

The total nitrogen emission levels (based on NOx and NH_3 emissions) for the project will be mitigated in part by the reduction in allowable annual NOx emissions from BEP. BEP provided offsets for 202 tons of NOx prior to first fire of the gas turbines but recently reduced allowable annual NOx emissions to 97 tpy. The net nitrogen emission change is shown below in Table 3.1-48. The detailed nitrogen emission calculations for the proposed new project and from the NOx reductions are included in Appendix 3.1B.

As shown in Table 3.1-48, the reduction in allowable NOx emissions from BEP will result in a reduction of total allowable nitrogen emissions, but there will be a net increase in total nitrogen emissions as a result of the project. The mitigation measures for this pollutant will provide NOx emission reduction credits as discussed in Section 3.1.8.

Table 3.1-48. Net Nitrogen Emissions Change for Proposed Project

Equipment	Total Nitrogen Emissions (as N)
New Equipment at SEP (Gas turbine, auxiliary boiler and fire pump engine)	93.4[a] tpy
Reduction in Permitted Emissions from BEP	(33.1 tpy)[b]
NOx ERCs provided for SEP	(32.0 tpy)
Net Emission Change	28.3 tpy

[a] Contains nitrogen associated with NOx and NH_3 emissions

[b] Reflects NOx reductions associated with the May 7, 2015, permit amendment that reduced NOx PTE for BEP from 202 to 97 tpy. While these reductions cannot be used as emission reduction credits, they can be recognized as mitigation for CEQA purposes.

3.1.8 Mitigation Measures

3.1.8.1 Construction Mitigation

MDAQMD Rule 403 governs the emissions of fugitive dust, prohibiting visible fugitive dust beyond property lines and requiring the minimization of fugitive dust emissions from excavation, grading, and land clearing operations. Construction impacts will be further minimized with the implementation of a construction fugitive dust and diesel-fueled engine control plan. This plan will focus on reducing construction air quality impacts and will encompass the construction mitigation measures listed below.

- Applying dust suppressants to unpaved roads and disturbed areas
- Limiting onsite vehicle speeds to 10 mph and posting the speed limit
- Applying dust suppressants frequently during periods of high winds when excavation/grading is occurring
- Sweeping onsite paved roads and entrance roads on an as-needed basis
- Replacing ground cover in disturbed areas as soon as practical
- Covering truck loads when hauling material that could be entrained during transit
- Applying dust suppressants or covers to soil stockpiles and disturbed areas when inactive for more than two weeks
- Using ultra-low sulfur diesel fuel (15 ppm sulfur) in all diesel-fueled equipment
- Using Tier 3 and Tier 4 construction equipment to the extent feasible
- Maintaining all diesel-fueled equipment per manufacturer's recommendations to reduce tailpipe emissions
- Limiting diesel heavy equipment idling to less than 5 minutes, to the extent practical
- Using electric motors for construction equipment to the extent feasible

Construction emissions and mitigation are described in more detail in Appendix 3.1C.

3.1.8.2 Operational Mitigation

During operation, the appropriate mitigation measure is to reduce potential air emissions before they are emitted. This is accomplished by the careful design of the project, including the installation of the BACT to minimize air emissions. Air quality impacts will be further mitigated by providing emission offsets. The remainder of this section describes the BACT analysis and the emission offset mitigation.

The detailed per unit daily emission calculations are included in Appendix 3.1.B, Table 3.1B-6. A comparison of potential emissions with the BACT thresholds in MDAQMD Rule 1303.A was presented in Table 3.1-46. This table shows that the turbine is required to use BACT for NOx, VOC, SO_2 and PM_{10}.

A detailed analysis of BACT options for the gas turbine is provided in Appendix 3.1D. A summary of the proposed controlled emission rates is provided in Table 3.1-49.

Table 3.1-49. Proposed Controlled Emission Limits

Pollutant	Control Technology	Proposed Limit
	Gas Turbine	
NOx	dry low-NOx combustors, selective catalytic reduction	2.0 ppmc (1-hour average) 1.5 ppmc (annual average)
CO	oxidation catalyst, good combustion practices	2.0 ppmc (1-hour average) 1.5 ppmc (annual average)
VOC	good combustion practices	2.0 ppmc (3-hour average) with duct firing 1.0 ppmc (3-hour average) without duct firing
SO_2	natural gas fuel	0.5 gr/100 dscf (short-term) 0.25 gr/100 dscf (annual average)

Table 3.1-49. Proposed Controlled Emission Limits

Pollutant	Control Technology	Proposed Limit
$PM_{10}/PM_{2.5}$	natural gas fuel	10 lb/hr (3-hour average) with duct firing 8 lb/hr (3-hour average) without duct firing
	Auxiliary Boiler	
NOx	ultra-low NOx burners	7 ppmc
CO	good combustion practices	50 ppmc
VOC	good combustion practices	10 ppmc
SO_2	natural gas fuel	--
$PM_{10}/PM_{2.5}$	natural gas fuel	--
	Emergency Engine	
NOx	turbocharging/intercooling; use of Tier 3 certified engine	2.56 g/bhp-hr
	Cooling Tower	
$PM_{10}/PM_{2.5}$	high-efficiency drift eliminators	0.0005% (drift rate)

For the gas turbine, the proposed BACT for NOx emissions is the use of dry low NOx combustors with SCR to control NOx emissions to 2.0 ppmvd (1-hour average). BACT for CO emissions is good combustion practices and the installation of oxidation catalyst systems to control CO emissions to 2.0 ppmvd (1-hour). BACT for VOC emissions is good combustion practices to control VOC emissions to 2.0 ppmvd with duct firing and 1.0 ppmvd (3-hour average) without duct firing.

For the auxiliary boiler, NOx emissions will be minimized through the use of ultra-low NOx burners to achieve a controlled NOx emission rate of 7 ppmvd @ 3% O_2 (3 hours). CO and VOC emissions will be minimized through good combustion practices and emission rates of 50 and 10 ppm, respectively. Good combustion practices and pipeline-quality natural gas will be used to minimize $PM_{10}/PM_{2.5}$ and SO_2 emissions. A complete top down BACT assessment for criteria pollutants is included in Appendix 3.1D.

Emission Offsets. MDAQMD Rule 1303.B requires that projects with operational emissions above 25 tons/year of NOx, VOC, or SOx, or 15 tons/year of PM_{10}, provide emission offsets resulting from emission reductions from other sources. As shown in Table 3.1-47 above, the net increase in annual NOx and VOC emissions from the project will exceed the District's offset thresholds. Compliance with the District's offset requirements is discussed above in Section 3.1.6.3.

3.1.9 Emissions Compliance Monitoring

The gas turbine will be equipped with continuous emissions monitoring systems to monitor and record exhaust concentrations of NOx, CO, and O_2. Fuel flow and ammonia injection rate will also be continuously monitored and recorded. The project owner will develop a procedure to calculate ammonia slip using the ammonia injection rate, the exhaust flow rate (calculated from monitored fuel flow), and measured NOx emissions. The procedure will be verified during annual emissions testing.

3.1.9.1 Locations of CEMS and Emissions Test Ports

The standard requirement for locating emissions test ports and CEMS sampling locations in an exhaust stack is at least 2 diameters downstream and 0.5 diameters upstream from the nearest flow disturbance (40 CFR 60, Appendix A, Methods 1 and 8A, respectively). For the SEP gas turbine, the nearest flow disturbance will be top of the transition from the HRSG to the stack, which will be located at an elevation of 92 feet above grade. The purpose of this requirement is to ensure that there is no stratification of the exhaust stream or cyclonic flow at the sampling location. Because the gas turbine exhaust stack has an internal diameter of 22.0 feet, the 2.0/0.5 requirement will dictate a minimum exhaust stack height of 92 feet + (2 * 22 ft) + (0.5 * 22 ft) = 147 feet.

Because of the location of the SEP near the Blythe Airport, the project owner desires to minimize the exhaust stack height of the gas turbine to the extent possible. Therefore, the project owner plans to construct a 140-foot stack and to request approval of an alternate test port location that will be approximately 1.7 diameters downstream of the last flow disturbance (the upstream distance of 0.5 stack diameters from the stack exit will be maintained). An alternative test port location can be approved, provided that the flow at the test site is shown not to experience cyclonic flow. Outlined below are the provisions of 40 CFR 60, Appendix A, Method 1 that are applicable to the proposed alternative test port location.

> *11.0 Procedure*
>
> 11.1 Selection of Measurement Site.
>
>> 11.1.1 Sampling and/or velocity measurements are performed at a site located at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, or contraction in the stack, or from a visible flame. If necessary, an alternative location may be selected, at a position at least two stack or duct diameters downstream and a half diameter upstream from any flow disturbance.
>>
>> 11.1.2 An alternative procedure is available for determining the acceptability of a measurement location not meeting the criteria above. This procedure described in section 11.5 allows for the determination of gas flow angles at the sampling points and comparison of the measured results with acceptability criteria…
>
> 11.5 The alternative site selection procedure may be used to determine the rotation angles in lieu of the procedure outlined in section 11.4.
>
>> 11.5.1 Alternative Measurement Site Selection Procedure. This alternative applies to sources where measurement locations are less than 2 equivalent or duct diameters downstream or less than one-half duct diameter upstream from a flow disturbance. The alternative should be limited to ducts larger than 24 in. in diameter where blockage and wall effects are minimal. A directional flow-sensing probe is used to measure pitch and yaw angles of the gas flow at 40 or more traverse points; the resultant angle is calculated and compared with acceptable criteria for mean and standard deviation.

For the CEMS measurement location in a source subject to a NSPS (such as the gas turbine, which is subject to Subpart KKKK), 40 CFR §60.13 (Monitoring Requirements) requires CEMS to be installed and operated in accordance with the provisions of 40 CFR 60 Appendix B, Performance Specification 2 (Specifications and Test Procedures for SO_2 and NOx Continuous Emission Monitoring Systems in Stationary Sources).

> *8.0 Performance Specification Test Procedure*
>
> *8.1 Installation and Measurement Location Specifications.*
>
>> *8.1.1 CEMS Installation. Install the CEMS at an accessible location where the pollutant concentration or emission rate measurements are directly representative or can be corrected so as to be representative of the total emissions from the affected facility or at the measurement location cross section Then select representative measurement points or paths for monitoring in locations that the CEMS will pass the RA test (see section 8.4). If the cause of failure to meet the RA test is determined to be the measurement location and a satisfactory correction technique cannot be established, the Administrator may require the*

CEMS to be relocated. Suggested measurement locations and points or paths that are most likely to provide data that will meet the RA requirements are listed below.

8.1.2 CEMS Measurement Location. It is suggested that the measurement location be (1) at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur and (2) at least a half equivalent diameter upstream from the effluent exhaust or control device….

8.1.3 Reference Method Measurement Location and Traverse Points.

8.1.3.1 Select, as appropriate, an accessible RM measurement point at least two equivalent diameters downstream from the nearest control device, the point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate may occur, and at least a half equivalent diameter upstream from the effluent exhaust or control device. When pollutant concentration changes are due solely to diluent leakage (e.g., air heater leakages) and pollutants and diluents are simultaneously measured at the same location, a half diameter may be used in lieu of two equivalent diameters. The CEMS and RM locations need not be the same.

During initial source testing, the stack flow characteristics at the reference method test port locations will be checked to ensure that they meet the “pitch” and “yaw” requirements of Part 60, Appendix A, Method 1 (cited above). The RATA will be used to demonstrate that the CEMS location is acceptable at the proposed sampling. If the procedure indicates that stratification exists at the CEMS and/or reference method test port locations, a multipoint probe will be used to ensure that representative samples are nevertheless obtained.

3.1.10 Comparison of Air Quality Impacts for the Proposed Modification

This section presents a comparison of emissions and air quality impacts of the proposed project with those of the licensed BEP II. The comparison demonstrates that:

- The air quality impacts from the proposed SEP will not result in any significant impact to public health
- The project will remain in compliance with all applicable laws, ordinances, regulations and standards
- The proposed changes to the project configuration will be beneficial to the public because the air quality impacts of the SEP will in most cases be lower than the air quality impacts of the BEP II

3.1.10.1 Impacts During Project Construction

Emissions from the SEP during project construction are quantified in Section 3.1.4.3 of the PTA. Construction of SEP is expected to take approximately 26 months, which is longer than the 16- to 20-month construction period estimated for BEP II.[38] Maximum estimated onsite criteria pollutant emissions during construction are shown for BEP II and SEP in Table 3.1-50. Estimated onsite construction emissions from SEP are below all MDAQMD CEQA significance thresholds and are lower than estimated BEP II onsite construction emissions for all pollutants except CO.

[38] Construction period is shown as 16 months in Section 5.2.3.6 and Appendix 5.2E and 20 months in Section 5.9.2.2 of the October 2009 BEP II PTA.

Table 3.1-50. Maximum Construction Emissions, SEP and BEP II

Emitting Activity	NOx	CO	VOC	PM10/PM2.5
Onsite Construction				
	Maximum Daily Emissions, lb/day			
Onsite Construction: SEP	85	169	5.1	20.2/4.3
Onsite Construction: BEP II[a]	147.2	62	20.5	85.0/23.9[b]
MDAQMD CEQA Significance Thresholds	137	548	137	82/82
	Maximum Annual Emissions, tpy			
Onsite Construction: SEP	7.4	14.5	0.4	2.5/0.5
Onsite Construction: BEP II[a]	19.43	8.18	2.7	3.51/1.5[c]
MDAQMD CEQA Significance Thresholds	25	100	25	15/15
All Project Construction, including Linear Features				
	Maximum Daily Emissions, lb/day			
Project Construction: SEP	353	651	25	58.0/18.2
Project Construction: BEP II[d]	152.8	89.7	22.9	49.2/16.4
MDAQMD CEQA Significance Thresholds	137	548	137	82/82
	Maximum Annual Emissions, tpy			
Project Construction: SEP	17	36	1.4	5.1/1.3
Project Construction: BEP II[d]	20.2	11.8	3.05	2.61/1.35
MDAQMD CEQA Significance Thresholds	25	100	25	15/15

Notes:

[a] BEP II onsite construction emissions from BEP Phase II Amendment, October 2009 (Caithness 2009), Appendix 5.2E, Tables 5.2E-1 and 5.2E-2.

[b] Shown as 47.6/15.8 lb/day in Table 5.2E-5 (Caithness 2009).

[c] Shown as 2.41/1.3 tpy in Table 5.2E-5 (Caithness 2009).

[d] BEP II onsite construction emissions from Table 5.2E-5 (Caithness 2009).

Total daily estimated construction emissions (onsite and offsite activities) for SEP are generally higher than total estimated construction emissions for BEP II. As discussed in Section 3.1.4.3, total daily estimated construction emissions for SEP will exceed the applicable NOx and CO significance thresholds, while total daily estimated construction emissions for BEP II exceed the significance threshold only for NOx. Estimated total annual emissions for both projects are below significance thresholds.

Estimated GHG emissions from SEP construction are compared with potential GHG emissions from the construction of BEP II in Table 3.1-51. Although total GHG emissions during construction of SEP are projected to be higher than those from BEP II, they remain well below the construction emissions significance threshold of 25,000 tons.

Table 3.1-51. Comparison of Estimated GHG Emissions During the Construction Period

	CO_2	CH_4	N_2O	CO_2e
SEP	7,139	1.1	0.0	7,166
BEP II[a]	4,744.8	0.29	0.18	4,806

Note:

[a] CO_2, CH_4 and N_2O emissions for BEP II from October 2009 PTA, CO2e Emissions Estimates table in Appendix 5.2E. CO_2e calculated using current GWPs.

3.1.10.2 Emissions During Project Operation

The SEP will consist of a single GE 7HA.02 gas turbine, instead of two Siemens SGT6-5000F gas turbines as permitted for BEP II. The performance and operating assumptions are compared in Table 3.1-52. Although the nominal rated output of SEP will be similar to the nominal rated output of BEP II, the total rated heat input of the two BEP II gas turbines is about 30 percent higher than the rated heat input for the SEP gas turbine. The licensed BEP II configuration was expected to use about 50 percent more fuel annually and to generate about 36 percent more electricity than the SEP.

Table 3.1-52. Comparison of Gas Turbine Performance Data and Operating Assumptions

Parameter	SEP	BEP II
Maximum heat input, MMBtu/hr (full load, ISO conditions)		
Without duct firing	3,243	2 x 2,109.6
With duct firing	3,466	2 x 2,241.2
Nominal rated output, MW (full load, ISO conditions, including steam turbine)	543	569
Expected annual heat input, MMBtu/yr	24,847,230	37,900,412
Expected annual generation, GWh net	3,790	5,142
Expected annual operating hours (including duct firing)	7,000	8,020
Expected annual duct firing hours	1,500	2,020
Expected annual startups	200	180 (each turbine)

Controlled emission limits from the SEP will be very similar to permitted limits for BEP II. The SEP proposed limits are compared with the BEP II permitted limits in Table 3.1-53 below.

Table 3.1-53. Comparison of Proposed Controlled Emission Limits

Pollutant	Control Technology	Proposed Limits, SEP	Permitted Limits, BEP II
Gas Turbine			
NOx	dry low-NOx combustors, selective catalytic reduction	2.0 ppmc (1-hour average) 1.5 ppmc (annual average)	2.0 ppmc (1-hour average)
CO	oxidation catalyst, good combustion practices	2.0 ppmc (1-hour average) 1.5 ppmc (annual average)	2.0 ppmc (1-hour average)
VOC	good combustion practices	2.0 ppmc (3-hour average) with duct firing 1.0 ppmc (3-hour average) without duct firing	2.0 ppmc (1-hour average) [a] with duct firing 1.0 ppmc (1-hour average) [a] without duct firing
SO_2	natural gas fuel	--	--
$PM_{10}/PM_{2.5}$	natural gas fuel	10 lb/hr (3-hour average) with duct firing 8 lb/hr (3-hour average) without duct firing	7.5 lb/hr for each gas turbine/HRSG, for a total of 15 lb/hr (3-hour average)

Table 3.1-53. Comparison of Proposed Controlled Emission Limits

Pollutant	Control Technology	Proposed Limits, SEP	Permitted Limits, BEP II
Auxiliary Boiler			
NOx	ultra-low NOx burners	7 ppmc (3-hour average)	9 ppmc (1-hour average)[a]
CO	good combustion practices	50 ppmc (3-hour average)	50 ppmc (1-hour average)[a]
VOC	good combustion practices	10 ppmc (3-hour average)	5 ppmc (1-hour average)[a]
SO_2	natural gas fuel	--	--
$PM_{10}/PM_{2.5}$	natural gas fuel	--	--
Emergency Diesel Fire Pump Engine			
All	turbocharging/intercooling; use of Tier 3 certified engine	--	--
Cooling Tower			
$PM_{10}/PM_{2.5}$	high-efficiency drift eliminators	0.0005% (drift rate)	0.0005% (drift rate)

Note:

[a] The MDAQMD permit indicates that these are 1-hour limits. However, since compliance is determined through source testing, compliance with the limits will actually be determined on a 3-hour average basis.

Emissions during gas turbine startup and shutdown are compared in Table 3.1-54. Although the BEP II gas turbines were designed to be fast-start units, cold starts were assumed to last up to 3 hours per gas turbine—significantly longer than the 45-minute cold startup time for the SEP gas turbine. Permitted BEP II startup and shutdown emissions are expressed on a per-unit basis, and the per-unit emissions have been doubled for this comparison since the BEP II project is a 2-on-1 design while SEP will use a single gas turbine/HRSG. Startup and shutdown emissions from SEP are expected to be significantly lower than those from BEP II for all pollutants and types of starts except for CO emissions during warm/hot starts, for which emissions are comparable.

Table 3.1-54. Comparison of Startup and Shutdown Emissions, SEP and BEP II

	Event Time, minutes	Gas Turbine Emissions, pounds per event			
		NOx	CO	VOC	$PM_{10}/PM_{2.5}$
Cold Start, SEP	45	181	132	10	6.6
Cold Start, BEP II[a]	180	241.8	280.8	101.4	45.0
Warm Start, SEP	40	146	130	10	5.9
Hot Start, SEP	21	97	123	9	3.1
Warm/Hot Start, BEP II	30	163.8	117.0	93.6	15.0
Shutdown, SEP	14	4.9	136	28	2.1
Shutdown, BEP II	30	59.4	50.6	41.8	3.6

Note:

[a] Emission limits for BEP II from MDAQMD's Authority to Construct. Permit limits are for a single turbine and have been multiplied by two for this comparison of facility emissions.

Estimated emissions during the commissioning period for the two project designs are summarized in Table 3.1-55 below. Maximum hourly NOx and CO emissions during commissioning of the SEP, which will occur during initial commissioning activities prior to tuning of the combustors and installation of the emission control systems, are significantly higher than hourly NOx and CO emissions analyzed for BEP II, primarily because the BEP II gas turbines were assumed to be commissioned one at a time. While total NOx emissions during the commissioning period are expected to be somewhat higher than those from BEP II, emissions of CO, VOC, and PM_{10}/$PM_{2.5}$ are expected to be the same or lower.

Table 3.1-55. Estimated Emissions During the Commissioning Period, SEP and BEP II

	NOx	**CO**	**VOC**	**PM_{10}/$PM_{2.5}$**
Emitting Activity	**Maximum Hourly Emissions, lb/hr**			
Commissioning Activities, SEP	625	4919	464	8.0
Commissioning Activities, BEP II[a] (each gas turbine)	193.5	2713.0	--[b]	--[b]
	Total Emissions During the Commissioning Period, tons			
Commissioning Activities, SEP	70	22	3	4.9
Commissioning Activities, BEP II[a]	51	407	51	2.5 to 7

Note:

[a] BEP II commissioning emissions from BEP Phase II Amendment, October 2009, Table 5.2-19 and p. 38.

[b] Data not provided.

The cooling tower and auxiliary boiler proposed for SEP will be slightly larger than the corresponding units utilized for BEP. Emissions and operating parameters for the SEP and BEP II units are compared in Table 3.1-56 and 3.1-57.

Table 3.1-56. Comparison of Auxiliary Boiler Emissions and Design Parameters

Parameter	SEP	BEP II
Maximum Heat Input, MMBtu/hr	66.3	60
Emissions		
NOx, lb/hr	0.56	0.55
SOx, lb/hr	0.09	0.14
CO, lb/hr	2.43	1.85
VOC, lb/hr	0.28	0.11
PM_{10}, lb/hr	0.46	0.27

Table 3.1-57. Comparison of Cooling Tower Emissions and Design Parameters

Parameter	SEP	BEP II
Number of cells per tower	10	11
Water Circulation Rate, gal/min	129,480	108,000
Drift Rate	0.0005%	0.0005%
Water Drift (lbs/hr)	323.6	269.9
TDS Level, mg/L	5000	5050
Emissions		
PM_{10}, lb/hr	1.6	1.4
PM_{10},tpy	7.1	6.0

A comparison of hourly, daily, and annual emissions is provided in Table 3.1-58 below. Daily and annual emissions from gas turbine(s), duct burner(s), auxiliary boiler, emergency diesel fire pump engine, and cooling tower are shown. Emissions from SEP will be well below permitted levels for BEP II for all pollutants except daily CO. This is consistent with SEP's slightly higher CO emission rate during startups, as gas turbine startup emissions dominate the daily CO emissions calculation.

Table 3.1-58. Comparison of Hourly, Daily and Annual Emissions, SEP and BEP II

	NOx	SOx	CO	VOC	$PM_{10}/PM_{2.5}$
Hourly, lb/hr[a]					
Proposed Limits, SEP Gas Turbine	26.0	4.9	15.8	9.0	10
Permitted Limits, BEP II Gas Turbines[b]	35.8	6.6	21.8	12.6	15
Daily, lb/day[c]					
Proposed Limits, SEP	920	120	967	286	289
Permitted Limits, BEP II[b]	1,168	154	892	499	380
Annual, tpy[c]					
Proposed Limits, SEP	85.6	8.8	78.0	24.3	40.1
Permitted Limits, BEP II[b]	169.4	13.3	110.7	51.9	60.9

Note:

[a] Hourly emissions reflect normal operation of one gas turbine at SEP and both gas turbines at BEP II. See Table 3.1-55 for a comparison of emission rates during startup and shutdown.

[b] Emission limits for BEP II from MDAQMD's Authority to Construct.

[c] Daily and annual emissions from gas turbine startups and shutdowns.

Annual GHG emissions from SEP are expected to be lower than those estimated for BEP II, chiefly because of different assumptions regarding annual gas turbine operation and resulting fuel use (see Table 3.1-52). Estimated annual GHG emissions for the two projects are shown in Table 3.1-59.

Table 3.1-59. Comparison of Estimated Annual GHG Emissions

	CO_2	CH_4	N_2O	CO_2e[b]
SEP	1,343,028	25	3	1,344,415
BEP II[a]	1,919,424	213	5	1,926,188

Note:

[a] CO_2, CH_4 and N_2O emissions for BEP II from October 2009 PTA, Table 5.2A-14. CO_2e calculated using current GWPs.

[b] The CO_2e emissions comparison shown here does not show potential sulfur hexafluoride leakage from circuit breakers, as potential SF_6 emissions were not quantified in the BEP II licensing documents.

3.1.10.3 Impacts During Project Construction

Maximum modeled impacts during the construction of SEP are compared with those of the licensed BEP II in Table 3.1-60.

Table 3.1-60. Comparison of Maximum Modeled Impacts During Construction

Pollutant	Averaging Time	Maximum Modeled Concentrations for SEP, μg/m³ [a]	Maximum Modeled Concentrations for BEP II, μg/m³ [b]
NO_2	1-Hour	130.7	62.8
	Annual	3.6	1.65
SO_2	1-Hour	1.9	0.064
	3-Hour	1.6	0.051
	24-Hour	0.4	0.013
CO	1-Hour	1,009.2	26.4
	8-Hour	504.6	10.1
PM_{10}	24-Hour	17.1	60.8
	Annual	1.3	1.95
$PM_{2.5}$	24-Hour	2.8	12.8
	Annual	0.2	0.45

Note:

[a] SEP alone; no BEP.

[b] Source: CEC 2012a, Air Quality Table 10.

Modeled NO_2, SO_2 and CO construction impacts for SEP are higher than modeled construction impacts for BEP II; however, modeled PM_{10} and $PM_{2.5}$ impacts are lower. Total construction impacts for BEP II exceeded the 24-hour $PM_{2.5}$ standard as well as the state PM_{10} standards. Total PM_{10} impacts during construction of SEP are also projected to exceed the state PM_{10} standards because existing background concentrations already exceed the standards, but total $PM_{2.5}$ impacts will be below both state and federal standards.

3.1.10.4 Impacts During Project Operation

Maximum modeled operation impacts for the licensed BEP II and the proposed SEP are compared in Table 3.1-61.

Table 3.1-61. Comparison of Maximum Modeled Impacts During Operation

Pollutant	Averaging Time	Maximum Modeled Concentrations for SEP, μg/m³	Maximum Modeled Concentrations for BEP II, μg/m³
NO_2	1-Hour	101.6[a]	113[b]
	98th pctl	53.8	[c]
	Annual	0.2	0.338
SO_2	1-Hour	2.9	6.2
	3-Hour	1.5	3.3
	24-Hour	0.4	0.9
	Annual	0.02	0.04
CO	1-Hour	117.9[a]	213[b]
	8-Hour	9.2	19.2
PM_{10}	24-Hour	5.3	2.85
	Annual	0.5	0.666

Table 3.1-61. Comparison of Maximum Modeled Impacts During Operation

Pollutant	Averaging Time	Maximum Modeled Concentrations for SEP, µg/m³	Maximum Modeled Concentrations for BEP II, µg/m³
$PM_{2.5}$	24-Hour Annual	5.3 0.5	2.85 0.666

Notes:

[a] Modeled concentrations reflect gas turbine startup, as well as fire pump engine operation.

[b] Modeled concentrations reflect startup of both gas turbines but exclude emergency diesel fire pump engine operation

[c] Modeled concentration not provided for facility alone.

Maximum modeled concentrations from the proposed SEP are lower than maximum modeled concentrations from the licensed BEP II project for all pollutants and averaging periods except 24-hour average PM_{10}/$PM_{2.5}$, in spite of the lower daily PM_{10}/$PM_{2.5}$ emission rate for SEP (see Table 3.1-58). For SEP, 24-hour average PM concentrations are dominated by the impacts from the cooling tower. The SEP cooling tower is somewhat shorter than the BEP II cooling tower (42 feet compared with 50 feet), and the SEP cooling tower has a somewhat higher water circulation rate, leading to slightly higher hourly emissions. The higher modeled 24-hour average PM impact may be because of these differences in cooling tower designs.

Maximum impacts from both the proposed SEP and the licensed BEP II are predicted to occur in roughly the same locations: NO_2, CO and PM impacts for all averaging periods and annual average SO_2 impacts are immediately south of the facility fenceline, because for both projects these impacts are predominantly as a result of downwash from sources with short stacks (emergency diesel fire pump engine and cooling tower). Impacts that are predominantly a result of the gas turbine (longer-term SO_2 and NO_2 and CO impacts during gas turbine startups) occur farther from the project site.

3.1.11 Changes to the Conditions of Certification

An ATC application will be submitted to the MDAQMD within two weeks of submittal of the PTA to the CEC. MDAQMD will then issue a Determination of Compliance with final permit conditions. The project owner expects that the CEC's conditions of certification for SEP will incorporate the MDAQMD Determination of Compliance, including those conditions related to approved ERCs for the project. The project owner also expects that the CEC staff will update the BEP II staff air quality conditions (designated AQ-SC) to reflect current standard staff conditions. Suggested revisions are shown in **underline** and ~~strikeout~~ fonts below.

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with conditions AQ-SC3, AQ-SC4 and AQ-SC5 for the entire duration of project **site** construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM delegates. The AQCMM and AQCMM delegates shall have full access to all areas of construction on the project site, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the compliance project manager (CPM).

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the CPM for approval the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM delegates. The AQCMM and all delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 [No changes]

AQ-SC3 Construction Fugitive Dust Control: [No changes]

A. [No changes]

B. [No changes]

C. No vehicle shall exceed ~~5~~ **10** miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

[No additional changes]

AQ-SC4 [No changes]

AQ-SC5 Diesel-Fueled Engine~~s~~ Control: ***

b. To meet the highest level of emissions reduction available for the engine family of the equipment, each piece of diesel-powered equipment shall be powered by a Tier 4 engine (**without add-on controls**), a Tier 4i engine (**without add-on controls**), or a Tier 3 engine with a post-combustion retrofit device verified by the ARB or the US EPA. For PM, the retrofit device shall be a particulate filter if verified, or a flow-through filter, or at least an oxidation catalyst. For NOx, the device shall meet the latest Mark level verified to be available ~~(as of January 2012, none meet this NOx requirement)~~.

[No additional changes]

AQ-SC6 [No changes]

QUARTERLY OPERATIONS REPORT

AQ-SC7 [No changes]

AQ-SC8~~9~~ The project owner shall ~~surrender the emission offset credits listed below or a modified list, as allowed by this condition, at the time, that surrender is required by Condition **AQ-18**. The ERC list shall contain evidence that the MDAQMD and the U.S. EPA have determined that the ERCs are real, enforceable, surplus, permanent, and quantifiable. The project owner may request CPM approval for any substitutions or modification of credits listed below.~~ **provide emission reductions in the form of offsets or emission reduction credits (ERCs) in the quantities of at least 85.6 tons/year NOx and 23.2 tons/year VOC emissions. The project owner shall demonstrate that the reductions are provided in the form required by the district.**

The project owner shall surrender the ERCs from among those that are listed in the district's Final Determination of Compliance Conditions or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions to the listed credits.

The CPM, in consultation with the District and the U.S. EPA, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) clearly will not cause the project to result in a significant environmental impact, and each requested change is consistent with applicable federal and state laws and regulations.

~~MDAQMD ERC Source~~	~~ERC Identification~~	~~NOx (tpy)~~	~~VOC (tpy)~~	~~PM10 (tpy)~~
~~CRIT Road Paving~~	~~MDAQMD (pending)~~			~~126~~

~~Existing ERC Held or Owned by Caithness Blythe II, LLC~~	~~MDAQMD -0058~~	~~25~~		
~~Existing ERC Held or Owned by Caithness Blythe II, LLC~~	~~MDAQMD -0051~~	~~175~~		
~~SoCal Gas Compressor Engines~~	~~MDAQMD - 0052~~	~~250~~		

Verification: The project owner shall submit to the CPM ~~a list of ERCs to be surrendered to the District at least 60 days prior to construction. The list of ERC's shall include evidence that the U.S. EPA and California ARB concurs with the determination that the ERCs are valid, including road-paving.~~ **<u>records showing that the project's offset requirements have been met prior to initiating construction.</u>** If the CPM, in consultation with the District, approves a substitution or modification, the CPM shall file a statement of the approval with the Energy Commission docket and mail a copy of the statement to every person on the post-certification mailing list. The CPM shall maintain an updated list of approved ERCs for the project.

3.1.12 References

Caithness Blythe II, LLC. 2009. *Petition to Amend the Blythe Energy Project Phase II (02-AFC-1C)*. October 26.

Caithness Blythe II, LLC. 2010. Blythe Energy Project Phase II Amendment, Data Responses Set II. October 1.

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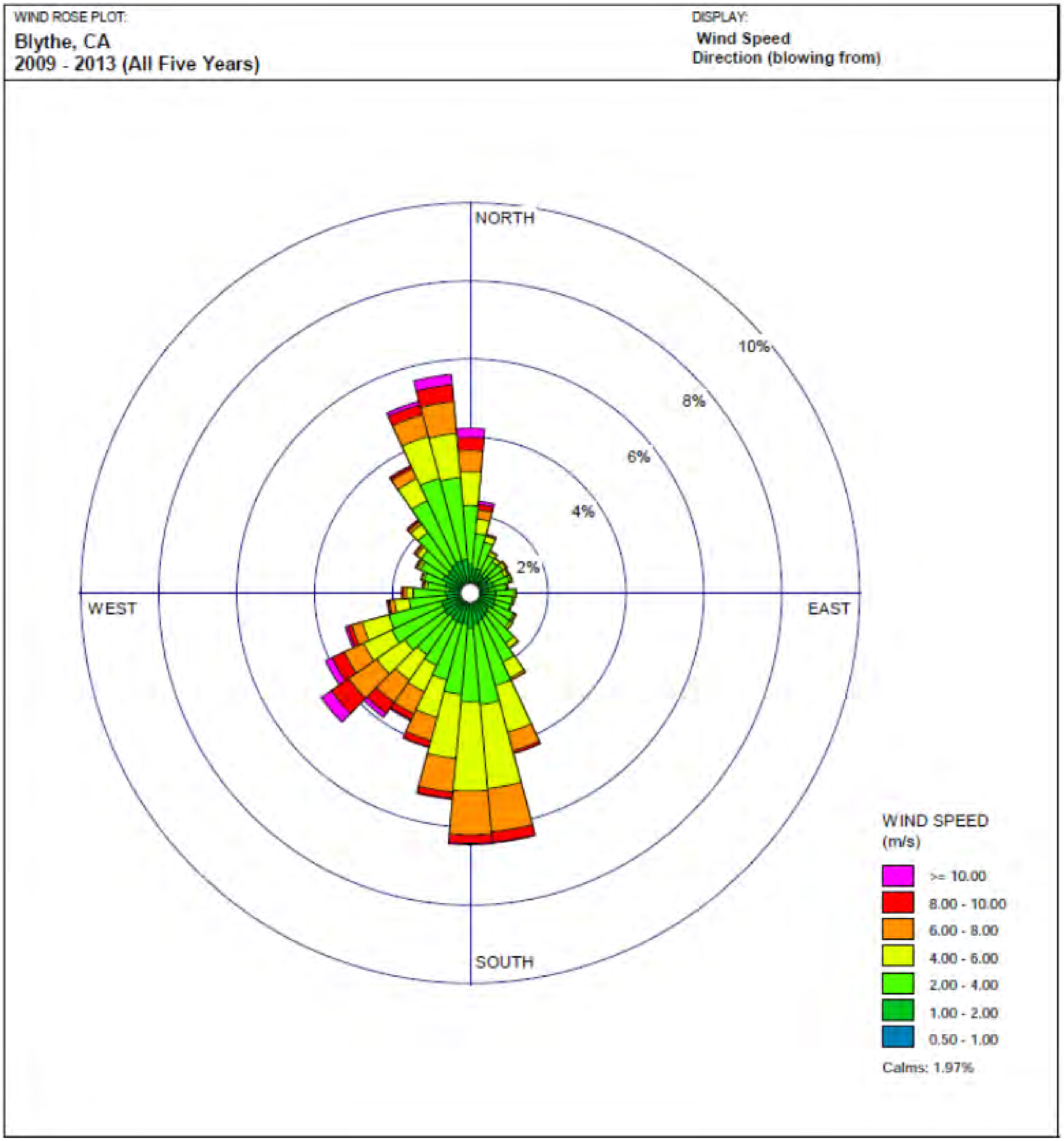

FIGURE 3.1-1
Composite Annual Wind Rose, Blythe (2009-2013)
Sonoran Energy Project
Riverside County, California

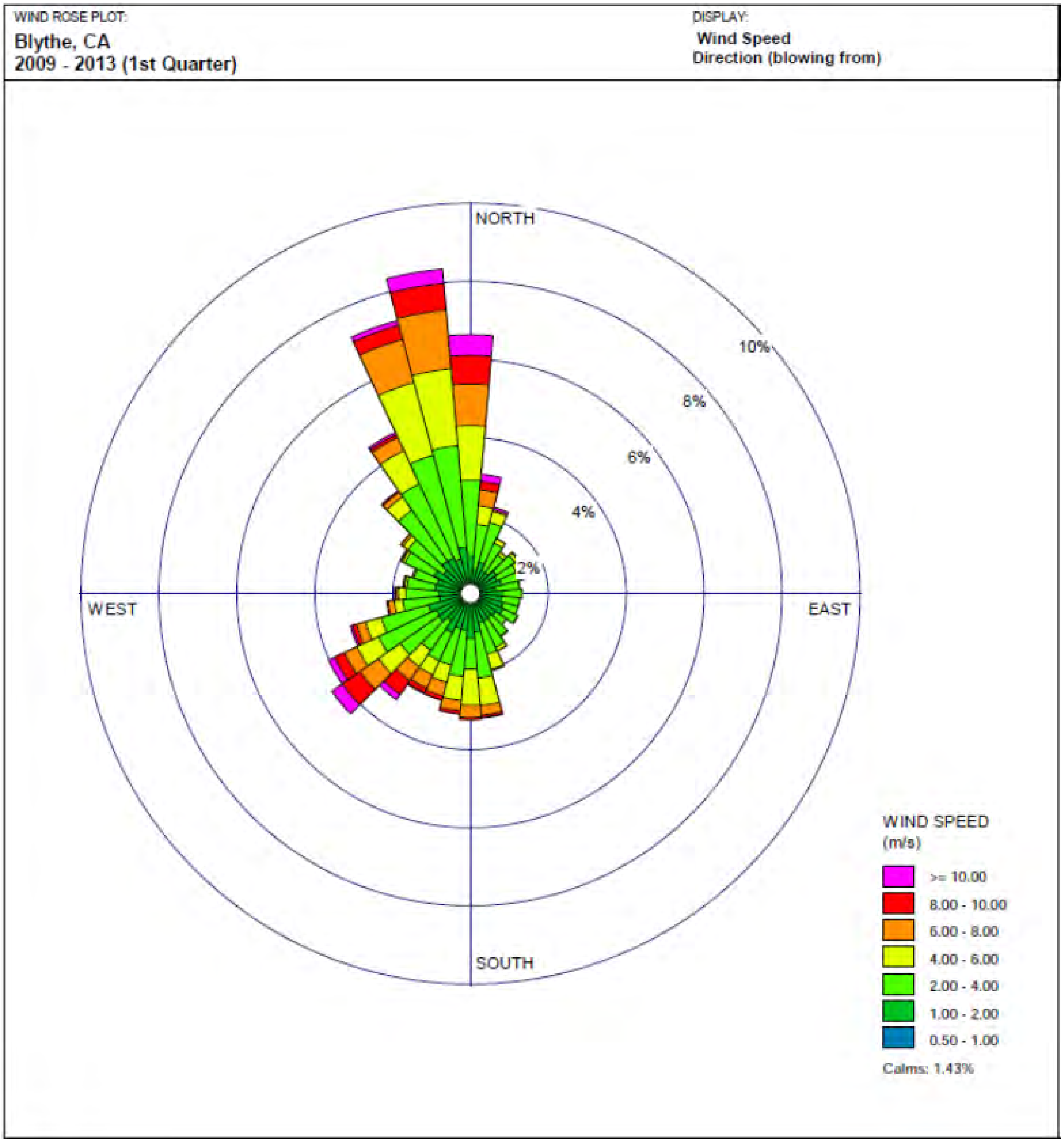

FIGURE 3.1-2
Composite Wind Rose, Q1, Blythe (2009-2013)
Sonoran Energy Project
Riverside County, California

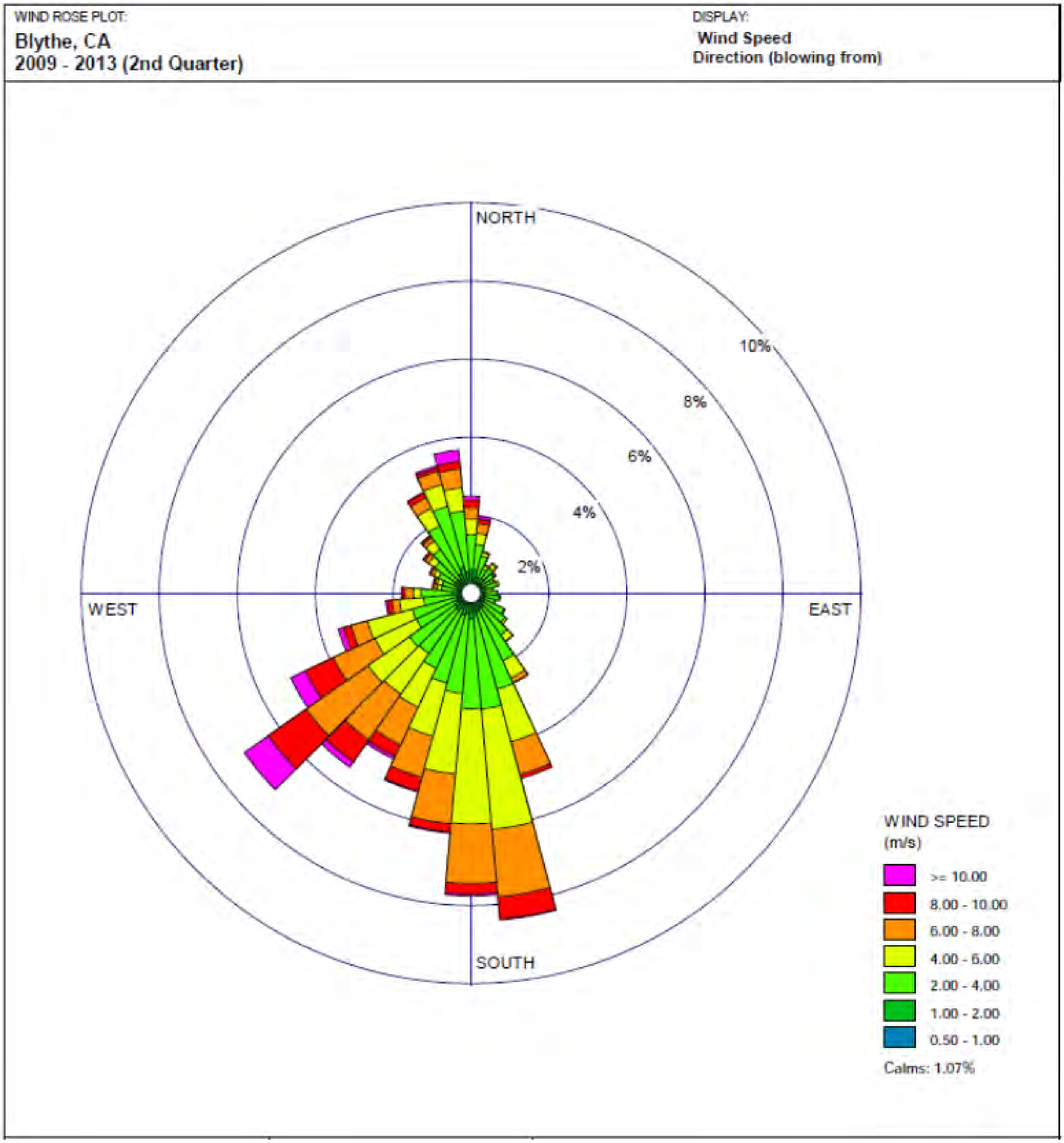

FIGURE 3.1-3
Composite Wind Rose, Q2, Blythe (2009-2013)
Sonoran Energy Project
Riverside County, California

CH2MHILL.

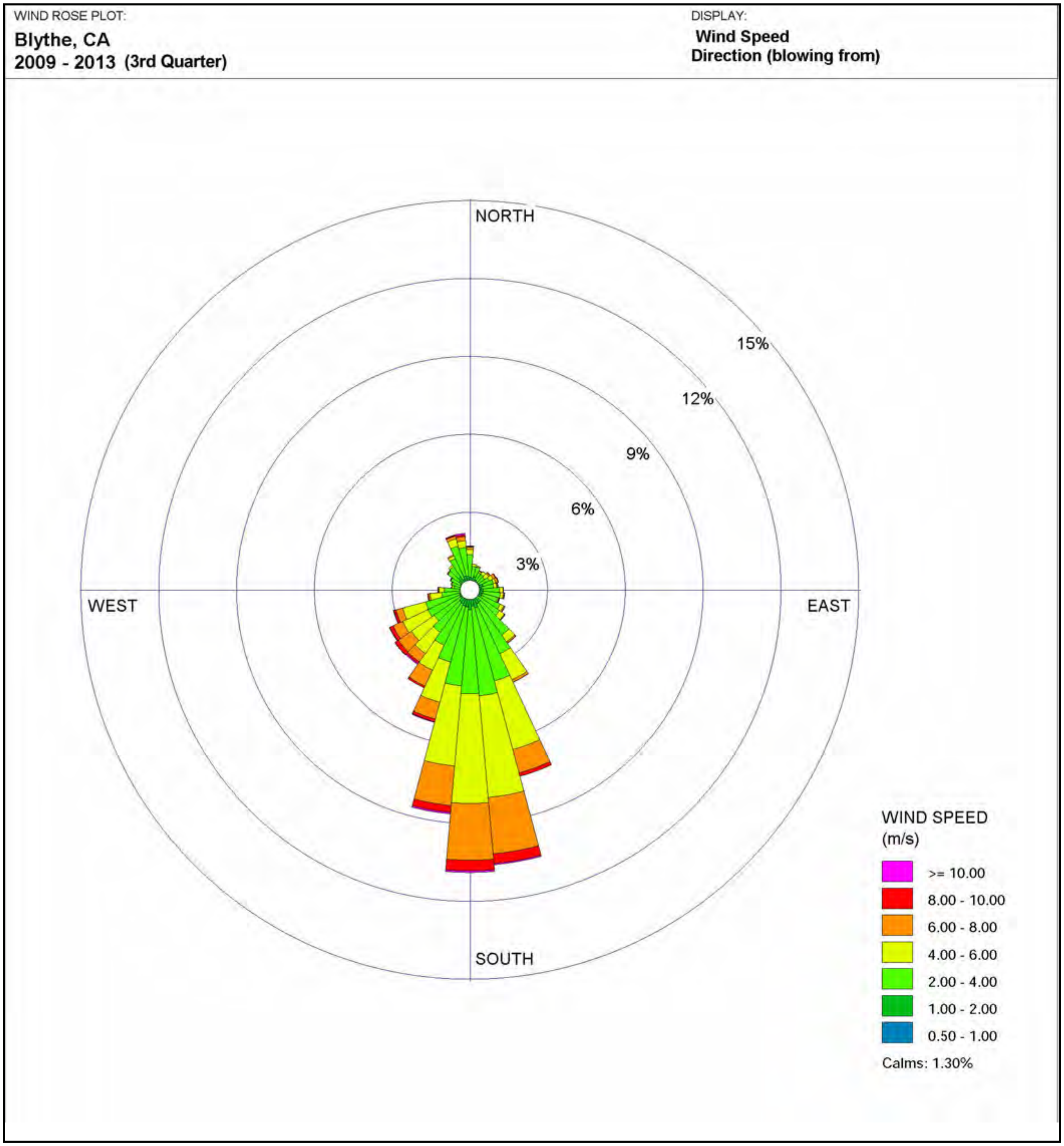

FIGURE 3.1-4
Composite Wind Rose, Q3, Blythe (2009-2013)
Sonoran Energy Project
Riverside County, California

CH2MHILL.

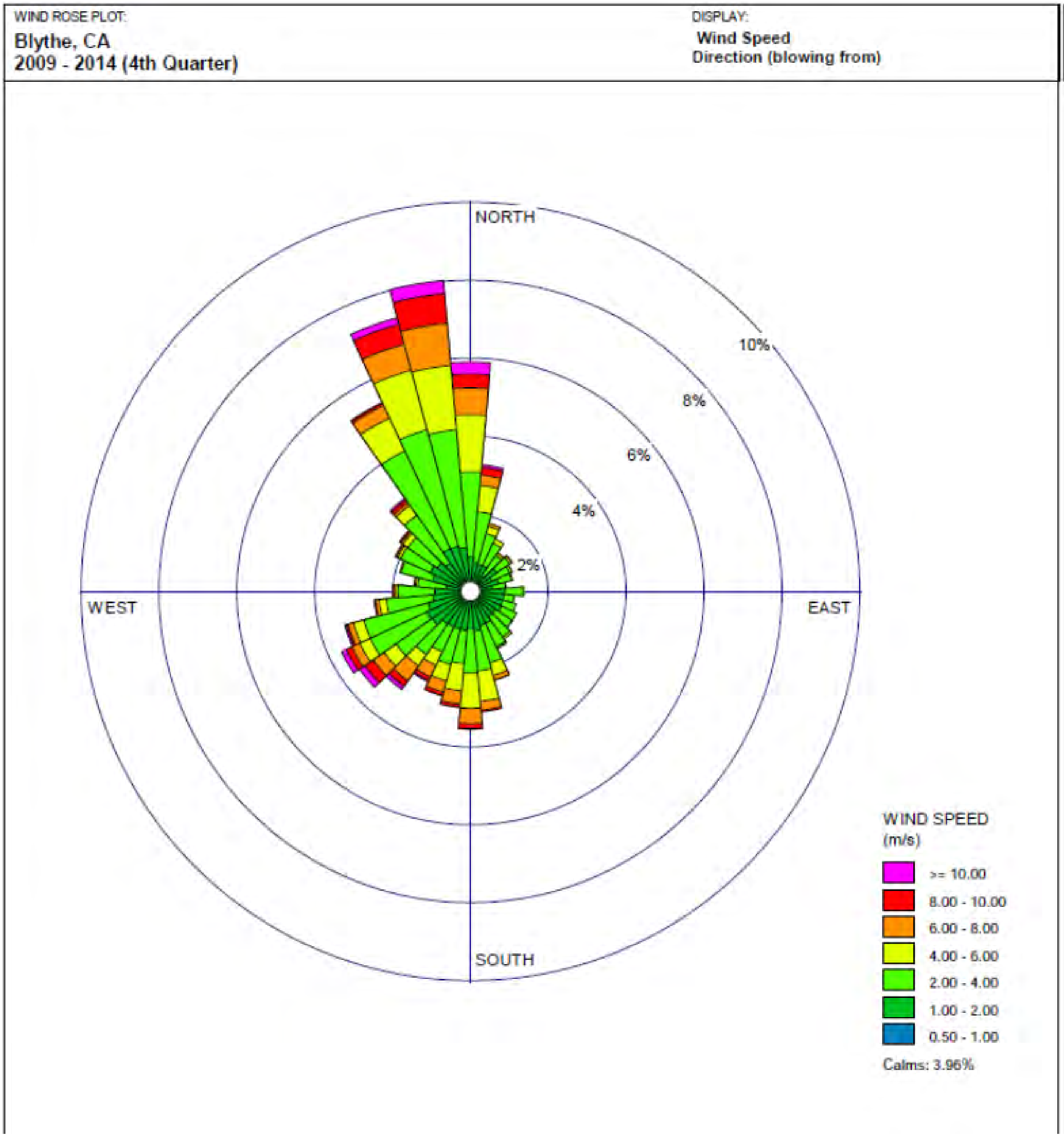

FIGURE 3.1-5
Composite Wind Rose, Q4, Blythe (2009-2013)
Sonoran Energy Project
Riverside County, California

FIGURE 3.1-6
Location of Background Air Quality Monitoring Stations
Sonoran Energy Project
Riverside County, California

CH2MHILL.

California Energy Commission (CEC). 2005. *Commission Decision for the Blythe Energy Project Phase II, Docket Number 02-AFC-01C*. Sacramento, California. December.

California Energy Commission (CEC). 2012. *Commission Decision for the Blythe Energy Project Phase II, Docket Number 02-AFC-01C, Amendment Order No. 12-0425-3a.* Sacramento, California. April.

3.8 Public Health

This section presents the methodology and results of a human health risk assessment performed to assess potential impacts and public exposure associated with airborne emissions from the construction and operation of SEP.

Emissions of combustion byproducts that have established NAAQS and CAAQS (referred to as “criteria pollutants”) are addressed in Section 3.1, Air Quality. Discussion of the potential health risks associated with these criteria pollutants is presented in this section.

The quantities of hazardous materials proposed to be stored onsite, a description of their uses, and the potential concerns regarding these materials are presented in Section 3.5, Hazardous Materials Management. A discussion of the potential concerns associated with electromagnetic field exposure is presented in Section2.3,Transmission Line Safety and Nuisances. To ensure worker safety during operation and construction, safe work practices will be followed (see Section 3.15, Worker Safety and Fire Protection).

3.8.1 Setting

SEP is located within the City of Blythe, approximately 5 miles west of the center of the city. The SEP site is a 76-acre parcel immediately adjacent to the existing, operational BEP.[42] SEP was acquired from Caithness Blythe II, LLC, by AltaGas Sonoran Energy Inc. in 2014. SEP was originally licensed by the CEC in 2000 as the Blythe II Energy Project.

SEP is a nominal 569-MW, combined-cycle power plant consisting of a GE 7HA.02 gas turbine, one supplemental-fired HRSG, one ST, an induced-draft cooling tower, an auxiliary steam boiler, an aqueous ammonia storage tank, an emergency diesel fire pump and ancillary facilities. This new proposed configuration will completely replace the licensed project configuration.

Construction of SEP will require onsite laydown and construction parking areas. Approximately 13.5 acres of construction laydown will be required. Construction worker parking for SEP will also be provided onsite. Construction worker parking will be located south of the construction area while the laydown areas will be located west and north of the construction area.

3.8.1.1 Project Overview as it Relates to Public Health

Air will be the dominant pathway for potential public exposure to noncriteria pollutants released by SEP. Emissions to the air will consist primarily of combustion by-products produced by the gas turbine/HRSG and auxiliary boiler. Potential health risks from combustion emissions will occur almost entirely by direct inhalation. To be conservative, additional pathways for dermal absorption, soil ingestion, mother’s milk ingestion and homegrown produce ingestion were part of the health risk modeling. The health risk assessment for SEP was conducted in accordance with guidance established by the California Office of Environmental Health Hazard Assessment (OEHHA)[43] and the ARB in 2015. [44] The new OEHHA guidance

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[42] 99-AFC-8C

[43] OEHHA. Air Toxics Hot Spots Program Risk Assessment Guidelines, The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments, February 2015.

[44] ARB. Consolidated Table of OEHHA/ARB-Approved Risk Assessment Health Values, May 15, 2015, http://www.arb.ca.gov/toxics/healthval/contable.pdf.

incorporates numerous changes, including age-specific cancer potency factors, breathing rates, and exposure durations. Sensitivity studies performed by the San Joaquin Valley Air Pollution Control District, the SCAQMD, and others have indicated that application of the new OEHHA risk guidance results in calculated risks that are two to three times higher than OEHHA's previous methodology for identical sources.

SEP will use new, efficient combined-cycle technology to minimize emissions of pollutants per unit of electric energy generated, thus minimizing potential effects on public health. It is beyond the scope of this analysis to describe the public health benefits that derive from the generated electric power that is provided to homes, businesses, hospitals, and other societal institutions.

3.8.2 Affected Environment

The CEC defines sensitive receptors as infants and children, the elderly, the chronically ill, and any other members of the general population who are more susceptible to the effects of exposure to environmental contaminants than the population at large.[45] Therefore, schools (public and private), daycare facilities, convalescent homes, and hospitals are of particular concern.

Because sensitive individuals may be located at any residential site, risk-based standards apply not only to sensitive receptors, but also to existing residences and places where residences may be built without a change in zoning. If project impacts are protective of sensitive individuals at the point of maximum impact, they are protective at all locations. Identification of sensitive receptors is typically done to ensure that notice of possible impacts is provided to the community.

In accordance with guidance from the CEC, a search was conducted for sensitive receptors within 6 miles of the project site. Based on the EDR *Offsite Receptor Report,*[46] sensitive receptors located within a 6-mile radius of the project area are as follows:

- 14 preschool/daycare centers
- 0 nursing homes
- 7 schools
- 24 hospitals, clinics, and/or pharmacies
- 1 college

Daycare, hospital, park, preschool, and school receptors found within 6 miles are shown in Figure 3.8-1A. The nearest sensitive receptor is Palo Verde College, located more than 2 miles northeast of the project site. The nearest existing residence is approximately 2700 feet west-southwest of the facility, south of W. Hobsonway. There are also two state prisons located approximately 13 miles west-southwest of the proposed project. The locations of the residence and the state prisons relative to the project site are shown in Figure 3.8-1B. The names, locations, and receptor numbers for all of the sensitive receptors are listed in Appendixes 3.8A and 3.8B.

In accordance with the requirements of CEC siting regulation Appendix B (g)(9)(c), the project owner conducted a search of available health studies concerning the potentially affected populations within a 6-mile radius. While there are no ambient monitors measuring TACs in the MDAB, there is an ambient monitor in Riverside County in the upwind South Coast Air Basin (SoCAB).[47] Air quality and health risk data presented by ARB in the *California Almanac of Emissions and Air Quality – 2009 Edition* (ARB, n.d.) for Riverside County show that over the period 1990 through 2005, the average concentrations for the

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[45] Siting regulation Appendix B (g)(9)(E)(i)

[46] The EDR receptor report was prepared for a site, also owned by APHUS, adjacent to SEP. Because SEP will be located farther away from the city of Blythe than the adjacent APHUS site, the sensitive receptors identified in the EDR report as being within 6 miles of the project are actually somewhat farther away.

[47] Air pollution transport from the SoCAB to the MDAB is discussed in Title 17 CCR Section 75000, Transport Identification.

top ten TACs have been substantially reduced, and the associated health risks are showing a steady downward trend as well.[48] ARB-estimated emissions inventory values for the top 10 TACs for 2012 for Riverside County and ambient levels and associated potential risks for Riverside County in the upwind SoCAB in 2013 are presented in Table 3.8-1.

Table 3.8-1. Top 10 TACs Emitted by All Sources in the Project Area

TAC	2012 Emissions, MDAB Portion of Riverside County (tons/year)	2013 Levels and Risks, Riverside County[a] Annual Average Concentration (ppbv)	Potential Carcinogenic Risk[b] (in 1 million)
Acetaldehyde	24	1.27	6
Benzene	21	0.307	28
1,3-Butadiene	23	0.065	24
Carbon tetrachloride	0.00	0.082	22
Chromium, hexavalent	0.00	0.058 ng/m^3	9
Para-Dichlorobenzene	1	0.15 (2006)	10 (2006)
Formaldehyde	49	3.57	26
Methylene chloride	6	1.33	5
Perchloroethylene	2	0.02	<1
DPM[c]	539	2.4 µg/m^3 (2000)	720 (2000)
Total Health Risk[d]	--	--	131

Source: Emissions data provided by ARB staff, extracted from the CEIDARS. Air Quality Planning and Science Division, Sacramento, CA - Rundate: September 22, 2014. TAC and Risk data from ARB Annual Toxic Site Summaries, http://www.arb.ca.gov/adam/toxics/toxics.html.

Notes:

[a] There are no ambient monitors in the MDAB that measure air toxics, so data from the Rubidoux, Riverside County ambient monitor in the SoCAB, which is upwind of the MDAB, is provided as a conservative estimate of background concentrations and health risks.

[b] Health Risk represents the number of excess cancer cases per million people based on a 70-year exposure to the annual average concentration. Health risk represents only the compounds listed in this table and only those with data for the year. There may be other significant compounds for which monitoring and health risk information is not available. The para-dichlorobenzene concentration and risk in 2006 are used for 2013. Para-dichlorobenzene was composed of values below the LOD for the later years; therefore, ARB stopped monitoring for para-dichlorobenzene in March 2007.

[c] The diesel particulate matter (DPM) concentrations are estimates for the SoCAB based on receptor modeling and are available only for selected years.

[d] Total Health Risk shown excludes DPM because DPM concentrations are not available for 2013.

ARB = California Air Resources Board
CEIDARS = California Emission Inventory Development and Reporting System
µg/m3 = micrograms per cubic meter
ng/m3 = nanograms per cubic meter
ppbv = parts per billion by volume
MDAB = Mojave Desert Air Basin
SoCAB = South Coast Air Basin
TAC = toxic air contaminant

48 Although ARB released an updated issue of the almanac in 2014, with the exception of (DPM), the updated version does not contain data on TACs.

A variety of studies have been published regarding cancer and respiratory illnesses and diseases in Riverside County and in the broader MDAB. In addition, the local public health department, Riverside County Health and Human Services, provides information on its website regarding public health issues for county residents (Riverside County, 2013). Asthma diagnosis rates in Riverside County are higher than average rates throughout the state for adults but slightly lower than the statewide average for children. The percentage of adults who have been diagnosed with asthma was 16.4 percent in 2007 through 2009, compared with 13.3 percent of the population statewide. Rates for children were 11.1 percent compared with 11.9 percent statewide for the same time period. According to the Centers for Disease Control (CDC), asthma is triggered by a variety of factors including dust, pollen, smoke, smog, and insects such as cockroaches.[49]

Cancer death rates in Riverside County remained relatively stable between 2006 and 2010, averaging 171.2 per 100,000. However, cancer death rates in the County remain slightly higher than the statewide average of 151.8 per 100,000 population (CDC, 2011).[50]

An additional respiratory illness for the area is the disease of Valley Fever (Coccidioidomycosis), which is found in six southwestern states including California. Riverside County is a suspected endemic area for Coccidioidomycosis according to the CDC (CDC, 2015c). In a recent study on the impact of Valley Fever in Riverside County between 2006 and 2010, the county had 305 reported cases, with 16 reported deaths. However, the County states that “At just over three cases for every 100,000 people, Coccidioidomycosis does not create an excess disease burden in Riverside County” (Riverside County, 2012).

3.8.3 Environmental Analysis

3.8.3.1 Air Toxics Exposure Assessment

This public health section discusses the sources and different kinds of air emissions associated with construction and operation of the project (see Section 3.1, Air Quality), the methodology used in performing the screening-level health risk assessment, and the results of the assessment of potential health risks from the project.

Project emissions to the air will consist of combustion byproducts from the natural-gas-fired gas turbine, auxiliary boiler, and cooling tower and from routine testing of the emergency diesel fire pump engine. Inhalation is the main pathway by which air pollutants can potentially cause public health impacts. Other pathways, including dermal absorption and ingestion of soil, homegrown vegetables, and mother’s milk, are also evaluated for potential exposure. As discussed below, these health impacts will not be significant.

Construction emissions are presented in detail in Section 3.1, Air Quality, and Appendix 3.1C, along with an air dispersion analysis demonstrating that with the exception of the state 24-hour PM_{10} standard (which is already being exceeded), ambient air quality standards will not be exceeded during project construction. The dominant emission with potential health risk is DPM from combustion of diesel fuel in construction equipment (e.g., cranes, dozers, excavators, graders, front-end loaders, backhoes). The analysis presented in Appendix 3.1F demonstrates that the potential incremental carcinogenic risk of DPM emissions during construction of SEP will be less than significant.

To evaluate potential health risks during project operation, the measures of these risks are first described in terms of the types of public health effects and the significance criteria and thresholds for those effects.

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[49] CDC, “Common Asthma Triggers,” http://www.cdc.gov/asthma/triggers.html

[50] CDC, “U.S. Cancer Statistics,” http://apps.nccd.cdc.gov/DCPC_INCA/DCPC_INCA.aspx. Statistic is death rate for all cancer sites combined, male and female, all races.

3.8.3.2 Significance Criteria

Significance criteria exist for both cancer and noncancer risks, and are discussed separately below.

Incremental Cancer Risk

Cancer risk is the probability or chance of contracting cancer over a human lifespan (assumed to be 70 years). Carcinogens are assumed to have no threshold below which there will be no human health impact. Any exposure to a carcinogen is assumed to have some probability of causing cancer: the lower the exposure, the lower the cancer risk (i.e., a linear, no-threshold model). For previous power plant projects the CEC has used an incremental cancer risk greater than 10 in one million as a significance threshold for public health. The 10-in-one-million risk level is also used by the Air Toxics "Hot Spots" (AB 2588) program and California's Proposition 65 as the public notification level for air toxic emissions from existing sources.

Animal studies or human epidemiological studies (often based on workplace exposures) are used to estimate the relationship between the dose of a particular carcinogen and the resulting excess cancer risk. The cancer potency factor for that carcinogen is the slope of that dose-response relationship. Cancer risk is estimated by multiplying the dose of a particular carcinogen by its cancer potency factor. The dominant exposure pathway is inhalation; however, additional exposure pathways are considered in this screening HRA.

Noncancer Health Impacts

Noncancer health effects can be either long-term (chronic) or short-term (acute). In determining potential noncancer health risks from air toxics, it is assumed there is a dose of the TAC below which there will be no human health impact. The air concentration corresponding to this dose is called the Reference Exposure Level (REL). A noncancer health impact is measured in terms of a health hazard quotient for each TAC, which is the modeled maximum annual concentration of each TAC divided by its REL. Health hazard quotients for TACs affecting the same target organ are typically summed, with the resulting totals expressed as health hazard indices for each organ system. A health hazard index of less than 1.0 is considered by the regulatory agencies to be a less-than-significant health risk. For this HRA, as a conservative assumption that will tend to overpredict risk, all hazard quotients were summed regardless of target organ. This methodology leads to a conservative (upper bound) assessment.

Chronic toxicity is defined as adverse health effects from prolonged chemical exposure, caused by chemicals accumulating in the body. Because chemical accumulation to toxic levels typically occurs slowly, symptoms of chronic effects usually do not appear until long after exposure commences. The lowest no-effect chronic exposure level for a noncarcinogenic air toxic is the chronic REL. Below this threshold, the body is capable of eliminating or detoxifying the chemical rapidly enough to prevent its accumulation. Chronic RELs have been established for 8-hour and 1-year periods. The chronic health hazard indices were calculated as the sum of the chronic health hazard quotients, each of which is calculated as the chronic TAC concentration for the appropriate averaging period, divided by the chronic REL of the TAC.

Acute toxicity is defined as adverse health effects caused by a brief chemical exposure of no more than 24 hours. For most chemicals, the air concentration required to produce acute effects is higher than the level required to produce chronic effects because the duration of exposure is shorter. Because acute toxicity is predominantly manifested in the upper respiratory system at threshold exposures, all acute health hazard quotients are typically summed to calculate the acute health hazard index. This method leads to an upper-bound assessment.

The maximum 1-hour average concentrations of each TAC with acute health effects is divided by the specific TAC's acute 1-hour REL to obtain the 1-hour health hazard quotient for health effects caused by relatively high, short-term exposure to air toxics.

3.8.3.3 Construction Impacts

Construction of SEP, from site preparation and grading to commercial operation, is expected to take place from the second quarter of 2016 to the second quarter of 2018 (22 months of construction activity followed by up to approximately 4 months of commissioning activities).

No significant public health effects are expected during construction. Strict construction practices that incorporate safety and compliance with applicable LORS will be followed. In addition, mitigation measures to reduce air emissions from construction impacts will be implemented as described in Section 3.1, Air Quality.

Temporary air emissions from construction are presented in detail in Appendix 3.1C, along with a criteria pollutant air dispersion analysis that demonstrates with the exception of the state 24-hour PM_{10} standard (which is already being exceeded), ambient air quality standards will not be exceeded during project construction. The dominant emission with potential health risk is DPM from combustion of diesel fuel in construction equipment (e.g., cranes, dozers, excavators, graders, front-end loaders, backhoes). DPM emissions from on-site construction are summarized in Table 3.8-2.

Table 3.8-2. Maximum Onsite DPM Emissions During Construction

Emitting Activity	Pounds per Day	Tons per Year
Construction Equipment	0.51	0.05

The potential cancer risk of DPM emissions during project construction was evaluated using the annual emission rate in Table 3.8-2 and the HARP2 model. The incremental cancer risk based on the 22-month construction period is 0.03 in one million, well below the significance threshold of 10 in one million. This HRA was performed in accordance with OEHHA guidance, which recommends adjusting the 30-year lifetime exposure risk for the actual exposure period of 22 months.

Ambient air modeling for PM_{10}, CO, SO_2, and NO_2 was performed as described in Section 3.1.5 and Appendix 3.1F. Construction-related criteria pollutant emission impacts are temporary and localized, resulting in no long-term significant health impacts to the public.

Small quantities of hazardous waste may be generated during construction of the project. Hazardous waste management plans will be in place so the potential for public exposure is minimal. Refer to Section 3.13, Waste Management, for more information. No acutely hazardous materials will be used or stored onsite during construction (see Section 3.5, Hazardous Materials Management). To ensure worker safety during construction, safe work practices will be followed (see Section 3.15, Worker Safety and Fire Protection).

3.8.3.4 Operation Impacts

Potential human health impacts associated with the project result from exposure to air emissions from operation of the natural gas-fired gas turbine, auxiliary boiler, and wet cooling tower and from routine testing of the new emergency diesel fire pump engine. The noncriteria pollutants emitted from the project encompass certain VOCs and polycyclic aromatic hydrocarbons (PAHs) from the combustion of natural gas, ammonia from the SCR NOx control system, and DPM from combustion of diesel fuel in the emergency diesel fire pump engine. These pollutants are listed in Table 3.8-3, and the detailed emission summaries and calculations are presented in Air Quality Appendix 3.1B.

For criteria pollutants, the proposed project will encompass the use of BACT as required under MDAQMD rules. Emissions of criteria pollutants will not cause or contribute significantly to violations of the NAAQS or CAAQS as discussed in Section 3.1, Air Quality.

Air dispersion modeling results (see Section 3.1.5.4) show that emissions will not result in ambient concentrations of criteria pollutants that exceed the ambient air quality standards, with the exception of the state PM_{10} standard. For this pollutant, existing 24-hour average PM_{10} background concentrations already exceed ambient standards. These standards are intended to protect the general public with a wide margin of safety. Therefore, the project will not have a significant impact on public health from emissions of criteria pollutants.

The screening HRA containing potential impacts associated with emissions of noncriteria pollutants to the air from the project is presented in below. The HRA was prepared using the latest version (HARP 2) of the ARB's HARP model (ARB, 2015), the May 2015 health database (OEHHA/ARB, 2015), and the OEHHA Hot Spots Program Guidance Manual (OEHHA, 2015).

Table 3.8-3. Pollutants Emitted to the Air from the Project

Criteria Pollutants	
Carbon monoxide	Oxides of sulfur
Oxides of nitrogen	Volatile organic compounds
Particulate matter	
Noncriteria Pollutants	
Acetaldehyde	Hexane
Acrolein	Naphthalene
Ammonia	PAHs
Benzene	Propylene
1,3-Butadiene	Toluene
Ethylbenzene	Xylene
Formaldehyde	

3.8.3.5 Public Health Impact Study Methods

Emissions of noncriteria pollutants from the project were analyzed using emission factors previously approved by ARB and the EPA. Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to analyze short-term and long-term arithmetic mean concentrations in air for use in the HRA. The EPA-recommended air dispersion model, AERMOD, was used along with five years (2009–2013) of compatible meteorological data from the Blythe airport meteorological station. The meteorological data combined surface measurements made at Blythe with upper air data from Elko, Nevada. The HARP 2 model was used with the air dispersion modeling output from the required air dispersion model, AERMOD, to perform the risk assessment.

Risk Analysis Method

The criteria pollutant modeling analysis was performed using the AERMOD model, the five-year meteorological data set described above, specific receptor grids, and the stack parameters for the combustion equipment (see Section 3.1, Air Quality). Receptors were also placed at the locations of the sensitive receptors shown in Figures 3.8-1A and 3.8-1B. The highest annual, 8-hour, and 1-hour average concentrations were used to determine cancer risk and acute health hazard index, and 8-hour and 1-year chronic health hazard indices, as appropriate. Health risks potentially associated with the estimated concentrations of pollutants in air were characterized in terms of potential lifetime incremental cancer risk (for carcinogenic substances), or comparison with RELs for noncancer health effects (for noncarcinogenic substances).

Health risks were evaluated for a hypothetical Maximally Exposed Individual (MEI) located at the Point of Maximum Impact (PMI), as well as risks to the MEI at residential locations (MEIR). The cancer risk to the MEI at the PMI is referred to as the Maximum Incremental Cancer Risk, or MICR. Human health risks associated with emissions from the project are unlikely to be higher at any other location than at the PMI. If there is no significant impact associated with concentrations in air at the PMI location, it is assumed to be unlikely that there will be significant impacts in any other location. Health risks were also evaluated at the nearest residence. The PMI (and thus the MICR) is not necessarily associated with actual exposure because in many cases the PMI is in an uninhabited area. Therefore, the MICR is generally higher than the cancer risk to the nearest existing resident. Both risks are based on 24 hours per day, 365 days per year, 30-year lifetime exposure, consistent with the new OEHHA guidance.

Health risks are also assessed for the hypothetical Maximally Exposed Individual Worker (MEIW) at the PMI. This assessment reflects potential workplace risks, which have a shorter duration than residential risks. Workplace risks reflect 8 hours per day, 245 days per year, 25-year exposure, consistent with the new OEHHA guidance.

Health risks potentially associated with concentrations of carcinogenic pollutants in air were calculated as estimated incremental lifetime cancer risks. The total cancer risk at any specific location is found by summing the contributions from each carcinogen.

The inhalation cancer potency factors and RELs used to characterize health risks associated with modeled concentrations in air are taken from the *Consolidated Table of OEHHA/ARB Approved Risk Assessment Health Values* (ARB, 2015) and are presented in Table 3.8-4.

Table 3.8-4. Risk Assessment Health Values for Air Toxic Substances

Compound	Inhalation Cancer Potency $(mg/kg\text{-}d)^{-1}$	Chronic Inhalation Reference Exposure Level ($\mu g/m^3$)	Acute Inhalation Reference Exposure Level ($\mu g/m^3$)
Acetaldehyde	0.010	140	470 (1-hr) 300 (8-hr)
Acrolein	—	0.35	2.5 (1-hr) 0.7 (8-hr)
Ammonia	—	200	3,200
Benzene	0.10	3.0	27 (1-hr) 3.0 (8-hr)
1,3-Butadiene	0.60	2.0	660 (1-hr) 9.0 (8-hr)
Ethyl Benzene	0.0087	2,000	—
Formaldehyde	0.021	9	55 (1-hr) 9 (8-hr)
Hexane	—	7,000	—
Naphthalene	0.12	9.0	—

Table 3.8-4. Risk Assessment Health Values for Air Toxic Substances

Compound	Inhalation Cancer Potency (mg/kg-d) $^{-1}$	Chronic Inhalation Reference Exposure Level (µg/m³)	Acute Inhalation Reference Exposure Level (µg/m³)
PAHs (as BaP)	3.9	—	—
Propylene	—	3,000	—
Propylene oxide	0.013	30	3,100
Toluene	—	300	37,000
Xylenes	—	700	22,000
Diesel Particulate Matter	1.1	5.0	--

Notes:
µg/m3 = microgram(s) per cubic meter
mg/kg-d = milligram(s) per kilogram per day

3.8.3.6 Characterization of Risks from Toxic Air Pollutants

The estimated potential maximum cancer risks for the MICR and the MEIW at the location of maximum impact (PMI), and for the MEIR, are shown in Table 3.8-5. The residential incremental cancer risks are shown for 30-year exposure, as recommended by OEHHA guidance. The incremental cancer risk based on 70-year exposure is also shown in parentheses to provide supplemental information about potential risks for longer-than-average exposure.[51] The incremental workplace cancer risks are shown for 25-year exposure, again as recommended by OEHHA guidance.

The maximum incremental cancer risk for the maximally exposed individual based on a 30-year exposure period is slightly above the 1-in-one-million threshold that triggers the use of toxics best available control technology (T-BACT), but is well below the CEC's 10–in-one-million threshold of significance. Potential cancer risk exceeds 1 in one million only at receptors along the southern fenceline of the project, along Hobsonway. Maximum incremental cancer risk at all other receptors, including sensitive, residential and workplace locations, is well below 1 in one million, even for a 70-year exposure period. The modeled incremental cancer risk is predominantly a result of DPM from the emergency diesel fire pump engine, which is assumed to operate for 200 hours per year. In reality, the emergency diesel fire pump engine will likely operate less than half that number of hours, with a proportionally lower cancer risk. The use of a Tier 3 engine is considered T-BACT.

Cancer risks potentially associated with the project were also assessed in terms of cancer burden. Cancer burden is a hypothetical upper-bound estimate of the additional number of cancer cases that could be associated with emissions from the project. Cancer burden is calculated as the maximum product of any potential carcinogenic risk greater than 1 in one million and the number of individuals at that risk level. Although the MICR is above 1 in one million, there are no residents or offsite workplaces within the area of exceedance so the potential cancer burden is zero.

[51] OEHHA guidance, Section 8.2.3.

Table 3.8-5. Summary of Estimated Maximum Potential Health Risks

Receptor	Carcinogenic Risk[a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index	
				8-hour	Annual
Maximally Exposed Individual (MEI) at PMI	1.3 in one million (1.5 in one million)	0	2.4×10^{-2}	1.5×10^{-3}	3.0×10^{-3}
Maximally Exposed Individual Resident (MEIR)[b]	0.07 in one million (0.08 in one million)	0	5.0×10^{-3}	2.5×10^{-4}	4.5×10^{-4}
Maximally Exposed Individual Worker (MEIW)	0.09 in one million[c]	0	--[d]	--[b]	--[b]
Significance Level	10	1.0	1.0	1.0	1.0

[a] Derived (OEHHA) Method used to determine cancer risks. Values in parentheses reflect 70-year exposure. See text.

[b] Risks at MEIR represent maximum risk at any sensitive receptor. Sensitive receptors may also be residences or workplaces.

[c] A worker is assumed to be exposed at the work location for 8 hours per day, instead of 24; for 250 days per year, instead of 365; and for 25 years, instead of 30.

[d] Acute analysis is always done as a single point exposure and is not affected by the type of analysis or exposure duration.

The maximum potential acute noncancer health hazard index for 1-hour exposure associated with concentrations in air is shown in Table 3.8-5. The acute noncancer health hazard index for all target organs falls well below 1.0, the threshold of significance.

The maximum potential chronic noncancer health hazard indices associated with concentrations in air are also shown in Table 3.8-5. The chronic noncancer health hazard indices also fall below 1.0, the CEC threshold of significance used for recent projects.

The estimates of cancer and noncancer risks associated with chronic or acute exposures are below thresholds used for regulating emissions of TACs to the air. Historically, exposure to any level of a carcinogen has been considered to have a finite risk of inducing cancer. There is no threshold for carcinogenicity. Because risks at low levels of exposure cannot be quantified directly by either animal or epidemiological studies, mathematical models have estimated such risks by extrapolation from high to low doses. This modeling procedure is designed to provide a highly conservative estimate of incremental cancer risks based on the most sensitive species of laboratory animal for extrapolation to humans (i.e., the assumption being that humans are as sensitive as the most sensitive animal species). Therefore, the risk is not likely to be higher than risks estimated using inhalation cancer potency factors and is most likely lower, and could even be zero (EPA, 1991).

The analysis of potential cancer risk described in this section employs methods and assumptions generally applied by regulatory agencies for this purpose. Given the importance of assuring public health, this analysis uses highly conservative methods and assumptions, meaning they tend to overpredict the potential for adverse effects. Conservative methodology and assumptions are outlined below.

- The analysis encompasses representative weather data over a period of 5 years to ensure that the least favorable conditions producing the highest ground-level concentration of power plant emissions are part of the analysis. The analysis then assumes that these worst-case weather conditions, which in reality occurred only once in 5 years, will occur continuously for 30-70 years.
- The project is assumed to operate at the hourly, daily, and annual emission conditions that produce the highest ground-level concentrations.
- The location of the highest ground-level concentration of project emissions is identified, and the analysis then assumes that a sensitive individual resides at this location 24 hours a day, 7 days a week over the entire 30-70 year period, even though these assumptions are physically impossible.

- The analysis addresses the new procedures and assumptions in the OEHHA guideline that increase risk (uses the new age-specific sensitivity factors and breathing rates) and some of the factors that reduce it (reduces residential and worker exposure time as recommended). On balance, the new OEHHA guidance has been found to increase the stringency of the cancer risk assessment by a factor as high as three.

Taken together, these methods and assumptions create a scenario that is more potentially adverse to human health than conditions that exist in the real world. For example, if the worst-case weather conditions could occur only on a winter evening but the worst-case emission rates could occur only on a summer afternoon, the analysis nonetheless assumes that these events occur at the same time. The point of using these conservative assumptions is to consciously overstate the potential impacts of the project. No one individual will experience exposures as great as those assumed for this analysis. By determining that even this highly overstated exposure will not be significant, the analysis provides a high degree of confidence that the much lower exposures that actual persons will experience will not result in any significant increase in cancer risk. In short, the analysis ensures that there will not be any significant public health impacts at any location, under any weather condition, under any operating condition.

3.8.3.7 Hazardous Materials

Hazardous materials will be used and stored at the facility. The hazardous materials stored in significant quantities onsite and descriptions of their uses are presented in Section 3.5, Hazardous Materials Management. Use of chemicals at the project site will be in accordance with standard practices for storage and management of hazardous materials; therefore, normal use of hazardous materials will not result in significant impacts on public health. Best management practices will be used, and mitigation measures will be in place to prevent releases. However, if an accidental release migrated offsite, potential impacts to the public could result.

The California Accidental Release Prevention (CalARP) Program regulations and Code of Federal Regulations (CFR) Title 40 Part 68 under the Clean Air Act establish emergency response planning requirements for acutely hazardous materials. These regulations require, among other things, preparation of a Risk Management Program (RMP), which is a comprehensive program to identify hazards and predict the areas that may be affected by a release of a program-listed hazardous material.

3.8.3.8 Operation Odors

The fuel used at SEP will be natural gas. Combustion contaminants and other exhaust constituents, including ammonia, will not be present at concentrations that could produce a significant odor.

3.8.3.9 Electromagnetic Field Exposure

Onsite the SEP will be electric power-handling transformers and associated equipment, which are discussed in more detail in Section 2.3, Transmission Line Safety and Nuisances. Based on findings of the National Institute of Environmental Health Sciences (NIEHS, 1999), electromagnetic field exposures from the electric power generating and handling equipment and associated transmission lines will not result in a significant impact on public health. The NIEHS report to the U.S. Congress found that “the probability that EMF exposure is truly a health hazard is currently small. The weak epidemiological associations and lack of any laboratory support for these associations provide only marginal scientific support that exposure to this agent is causing any degree of harm.” (NIEHS, 1999).

3.8.3.10 Summary of Impacts

Results from the HRA based on emissions modeling indicate that there will be no significant incremental public health risks from construction or operation of SEP. Results from criteria pollutant modeling for routine operation indicate that potential ambient concentrations of NO_2, CO, SO_2, and PM_{10} will not exceed ambient air quality standards, with the exception of the state PM_{10} standards. For this pollutant, existing background concentrations already exceed applicable standards, and the project will not add a significant contribution. The ambient air quality standards protect public health with a margin of safety for the most sensitive subpopulations (Section 3.1).

3.8.4 Cumulative Effects

CEQA requires an analysis of potential cumulative air quality impacts that may result from the project and other past, present, and reasonably foreseeable projects. The project owner submitted a letter to MDAQMD requesting the following information regarding other projects that qualify for review under the cumulative air quality impact analysis:[52]

- Projects located within a 6-mile radius of the SEP project site
- Projects issued a new Authority to Construct permit after January 1, 2012

MDAQMD has responded that no projects meeting these criteria have been identified, other than the existing, adjacent BEP. Potential cumulative impacts of other development projects within 6 miles of the project site, including the existing, adjacent BEP, are discussed in Appendix 3.1G.

In contrast with the approach used to estimate impacts for criteria pollutants, the significance thresholds developed for TACs are set sufficiently stringent so as to preclude the potential for any significant cumulative impacts. Thus, a separate cumulative impacts analysis for TACs is not required.

3.8.5 Mitigation Measures

The project has been designed to minimize TAC emissions and impacts. No additional mitigation measures are needed for the project TAC emissions because the potential air quality and public health impacts are less than significant.

3.8.6 Consistency with Laws, Ordinances, Regulations, and Standards

A demonstration of compliance with applicable LORS is presented in this section.

3.8.6.1 Federal LORS

Clean Air Act

The Clean Air Act requires large projects (new or modified sources at major stationary sources) to go through a federal permitting process that ensures that the project will not cause or contribute to a violation of a national ambient air quality standard. The emissions from SEP are below the thresholds for applicability of the federal permitting requirements.

40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)

The federal National Emission Standards for Hazardous Air Pollutants (NESHAP) program establishes national emission standards to limit emissions of hazardous air pollutants (HAPs, or air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution, but for which NAAQS have not been established) from major sources of HAPs in specific source categories. The NESHAPs for gas turbines (Subpart YYYY) and for reciprocating IC engines (Subpart ZZZZ) are potentially applicable to the proposed project. Compliance with the applicable NESHAPs is discussed in Section 3.1, Air Quality.

40 CFR Part 68 (Risk Management Plan)

Facilities storing or handling significant amounts of acutely hazardous materials are required to prepare and submit risk management plans. No regulated substance will be present in quantities exceeding the applicability thresholds.

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[52] Copies of the correspondence are provided in Appendix 3.1G.

3.8.6.2 State LORS

Health and Safety Code 25249.5 et seq. (Safe Drinking Water and Toxic Enforcement Act of 1986—Proposition 65)

Activities that expose the public to significant levels of chemicals that are carcinogenic or that can cause reproductive harm must provide warnings. Based on an HRA that follows ARB/OEHHA guidelines, noncriteria pollutant emission rates and resulting doses and carcinogenic risks will not exceed thresholds that require Proposition 65 exposure warnings.

Health and Safety Code, Article 2, Chapter 6.95, Sections 25531 to 25541; CCR Title 19 (Public Safety), Division 2 (Office of Emergency Services), Chapter 4.5 (California Accidental Release Prevention Program)

Facilities storing or handling significant amounts of acutely hazardous materials are required to prepare and submit risk management plans.

An RMP will be prepared to address potentially hazardous materials stored or used at SEP.

Health and Safety Code Sections 44360 to 44366 (Air Toxics “Hot Spots” Information and Assessment Act—AB 2588)

Under this program, facilities with emissions of TACs are prioritized based on emissions. If the facility’s priority score is high enough, the facility is required to prepare an HRA. High-risk facilities may be required to provide notification to neighbors or to develop and implement a risk reduction plan.

Based on the emission estimates described in this report, SEP will not be a high-priority facility.

3.8.6.3 Local LORS

New Source Review Requirements for Air Toxics

MDAQMD Rule 1320 describes the requirements and standards for evaluating the potential impact of TACs from facilities that emit TACs. The rule requires a demonstration that a new or modified source will not exceed the applicable health risk thresholds.

Based on the results of the HRA described in this section, the project will not exceed the applicable health risk thresholds.

MDAQMD Rule 1320 also describes the requirements, procedures, and standards for evaluating the potential impact of TACs from new sources and modifications to existing sources that are major sources of HAPs. Based on the emissions estimates described in this Petition, SEP will be a major source of hazardous air pollutants because the project is considered part of the same stationary source as the existing BEP. Therefore, the project will be subject to the rule requirements for federal Toxic New Source Review (Federal T-NSR) and will be subject to MACT requirements. Because the proposed gas turbine will utilize an oxidation catalyst, the MACT requirements are expected to be satisfied.

3.8.7 Comparison of Public Health Impacts for the Proposed Modification

This section presents a comparison of project emissions and risks related to public health impacts of the proposed project with those of the licensed BEP II.

3.8.7.1 Construction Impacts

Emissions and ambient air quality impacts for criteria pollutants from construction of SEP were compared with emissions and impacts from construction of BEP II in Section 3.1.5.4. Construction of SEP is expected to take approximately 26 months, including 4 months of commissioning, compared with 16 to 20 months for BEP II. Noncriteria emissions of concern to public health during project construction are DPM, which are emitted on and near the project site by diesel-fueled construction equipment. DPM emissions from onsite construction activities were estimated for both projects and are compared in Table 3.8-1.

Table 3.8-1. Comparison of Maximum Onsite DPM Emissions During Construction

Emitting Activity	Pounds per Day	Tons per Year
Construction Equipment: SEP	0.51	0.05
Construction Equipment: BEP II	7.4	0.98

Potential incremental cancer risk from DPM emitted during onsite construction was not evaluated for BEP II. Potential incremental cancer risk from DPM from SEP construction is approximately 0.03 in one million; refer to the discussion in Section 3.8.3.2.

3.8.7.2 Impacts During Project Operation

A comparison of the results of the screening health risk assessment for SEP and BEP II is presented in Table 3.8-7. This comparison shows that cancer risk for both projects, which is driven by the emergency diesel fire pump engine, is well below the 10 in one million significance threshold. The acute and chronic health hazard indices are also well below the significance threshold of 1 for both projects.

Table 3.8-7. Summary of Estimated Maximum Potential Health Risks

Receptor	Carcinogenic Risk[a] (per million)	Cancer Burden	Acute Health Hazard Index	Chronic Health Hazard Index	
				8-hour	Annual
Maximally Exposed Individual (MEI) at PMI, SEP	1.3 in one million (1.5 in one million)	0	2.4×10^{-2}	1.5×10^{-3}	3.0×10^{-3}
Maximally Exposed Individual (MEI) at PMI, BEP II[b]	1.81 in one million 0.7 in one million	0.0032 n/a	0.348	--[c]	0.0295
Significance Level	10	1.0	1.0	1.0	1.0

[a] Derived (OEHHA) Method used to determine cancer risks. Values in parentheses reflect 70-year exposure. See text.

[b] All BEP II health risk values from BEP Phase II Amendment; Appendix 5.2D, Table 5.2D-3, shows cancer risk as 1.81 in one million and the cancer burden as “n/a,” while the text of Section 5.9.2.5 states that the cancer risk is 7×10^{-7} and the cancer burden is ~0.0032. The cancer burden will by definition be zero if the cancer risk is less than 1 in one million, so these results are internally inconsistent.

[c] No 8-hour chronic risk was presented for BEP II.

3.8.8 Changes to the Conditions of Certification

The original BEP II license included a public health-related Condition of Certification requiring annual visual inspections of the cooling tower drift eliminators and an inspection by the cooling tower vendor’s field representative prior to initial operation. The condition also permitted the CPM to require periodic source testing of the PM_{10} emissions from the cooling tower.

The project owner believes that these conditions are duplicative of the cooling tower-related conditions that were imposed by the MDAQMD and incorporated into the Air Quality Conditions of Certification for the currently licensed project (see Condition of Certification AQ-38 through AQ-43 of the BEP II license). These conditions will ensure that the cooling tower drift eliminators are constructed and maintained in a manner that will minimize cooling tower drift. Therefore, the project owner requests that Condition PH-1 be removed.

3.8.9 References

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U.S. Environmental Protection Agency (EPA). 2005. *Guideline on Air Quality Models*, 40 CFR, Part 51, Appendix W, November.

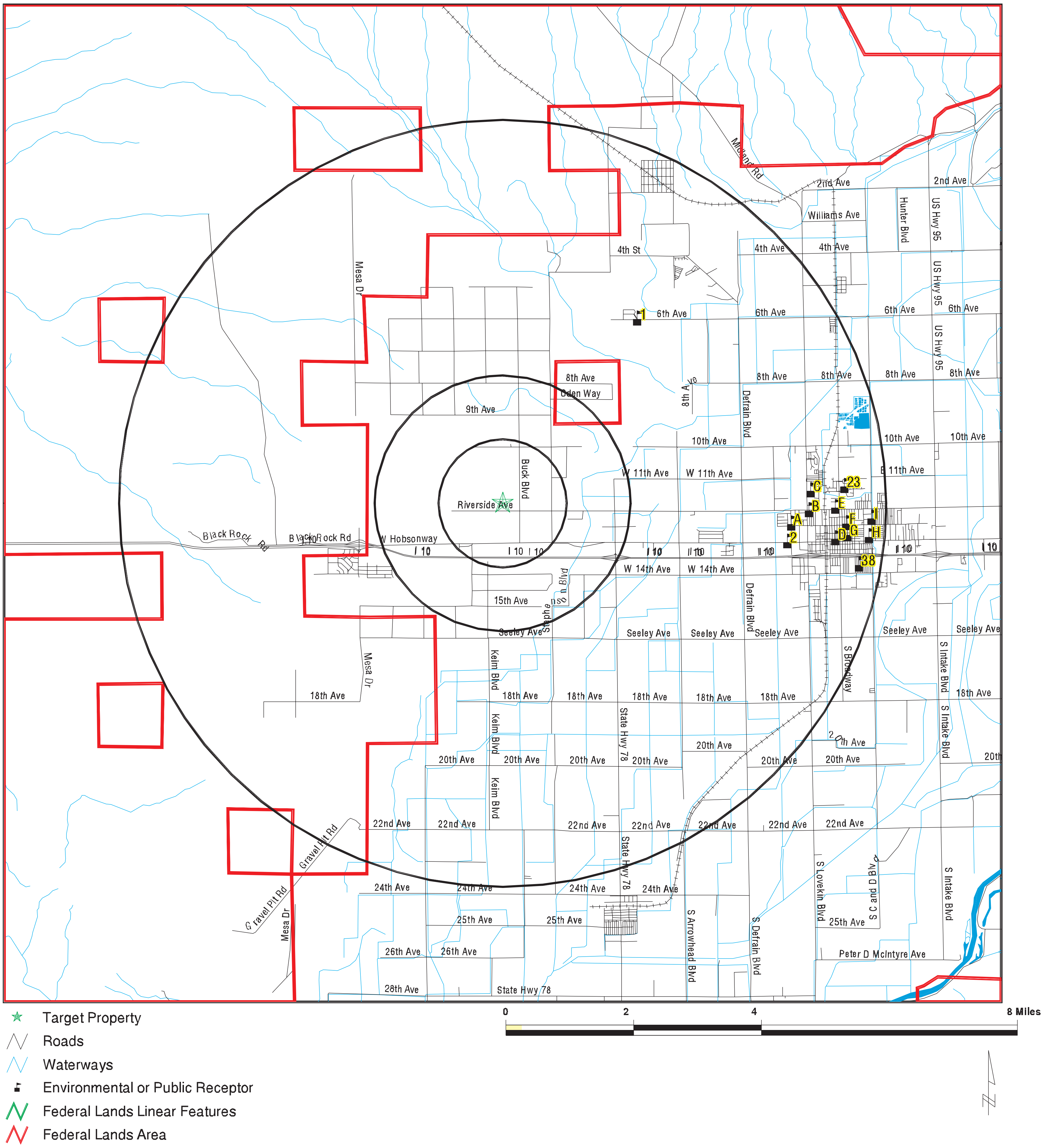
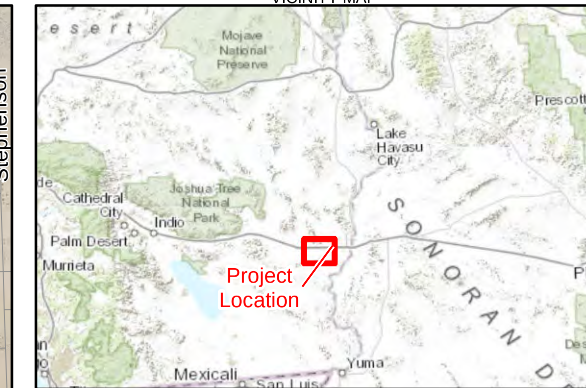


FIGURE 3.8-1A
Sensitive Receptors
Sonoran Energy Project
Riverside County, California

CH2MHILL.

VICINITY MAP



LEGEND

- Additional Sensitive Receptor
- Property Boundary

Image Source: NAIP 2012

0 1.25 2.5
Miles

N

FIGURE 3.8-1B
Additional Sensitive Receptors
Sonoran Energy Project
Riverside County, California

\\BALDUR\PROJ\SEP\MAPFILES\SEP_SENSITIVERECEPTOR.MXD KMINO 7/13/2015 12:16:00 PM

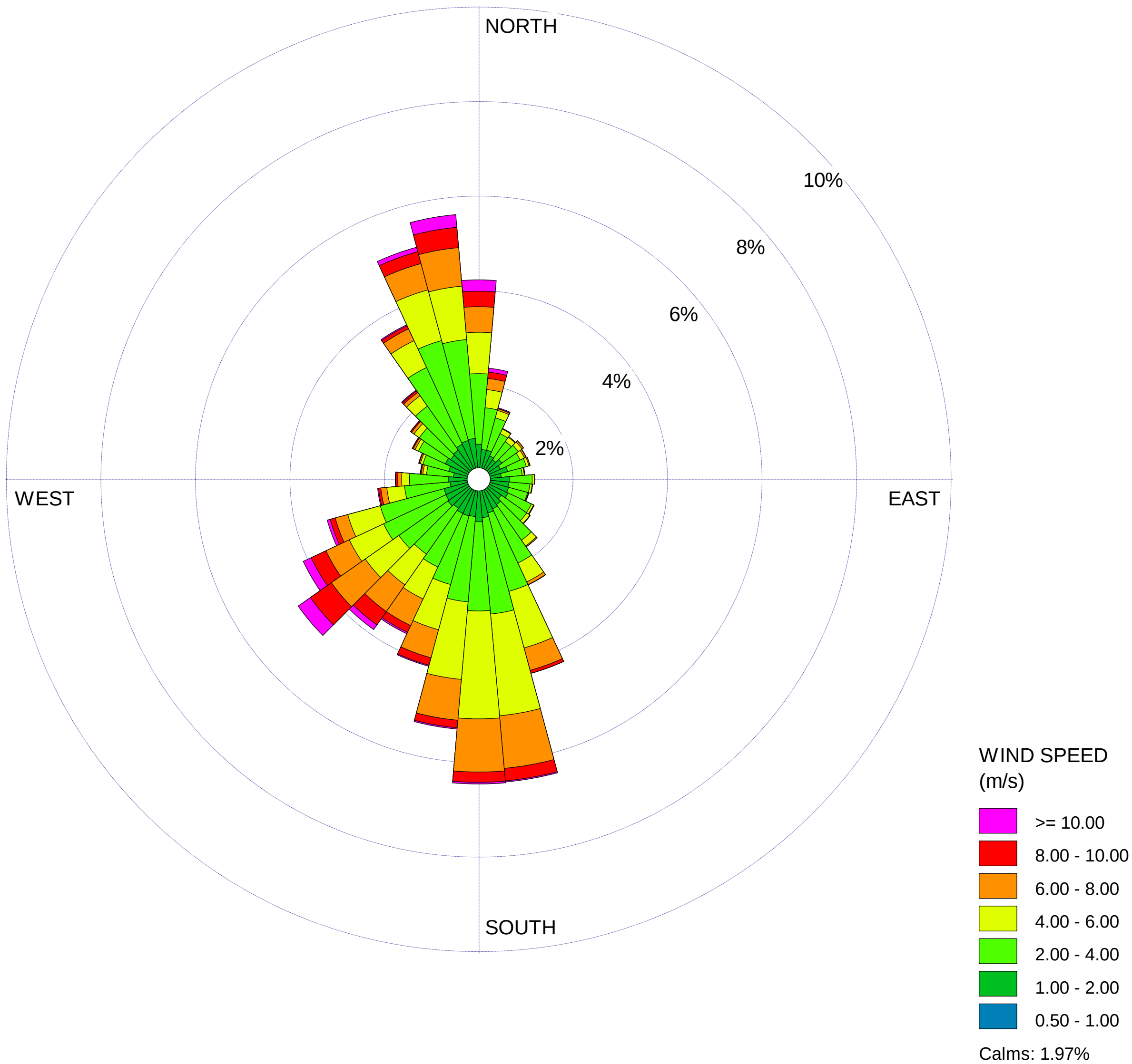
Appendix 3.1A
Quarterly Wind Roses and Wind Frequency Distributions

WIND ROSE PLOT:

Blythe, CA
2009 - 2013 (All Five Years)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 1/1/2009 - 00:00** **End Date: 12/31/2013 - 16:00**		
		MODELER:	
	CALM WINDS: **1.97%**	TOTAL COUNT: **43627 hrs.**	
	AVG. WIND SPEED: **3.64 m/s**	DATE: **8/5/2014**	PROJECT NO.:

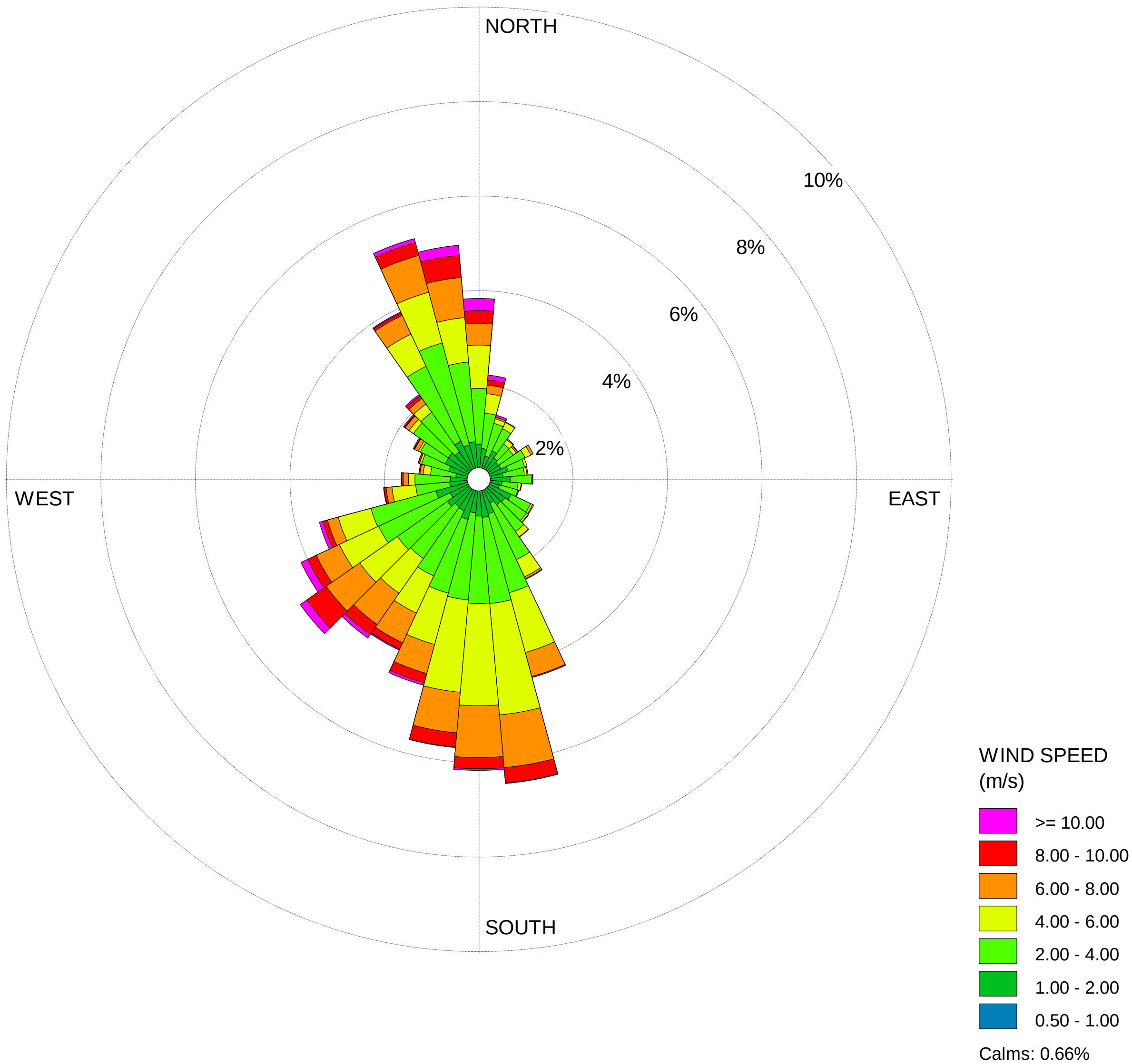
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2009 (All Year)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 1/1/2009 - 00:00
End Date: 12/31/2009 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.66%

TOTAL COUNT:

8747 hrs.

AVG. WIND SPEED:

3.72 m/s

DATE:

8/5/2014

PROJECT NO.:

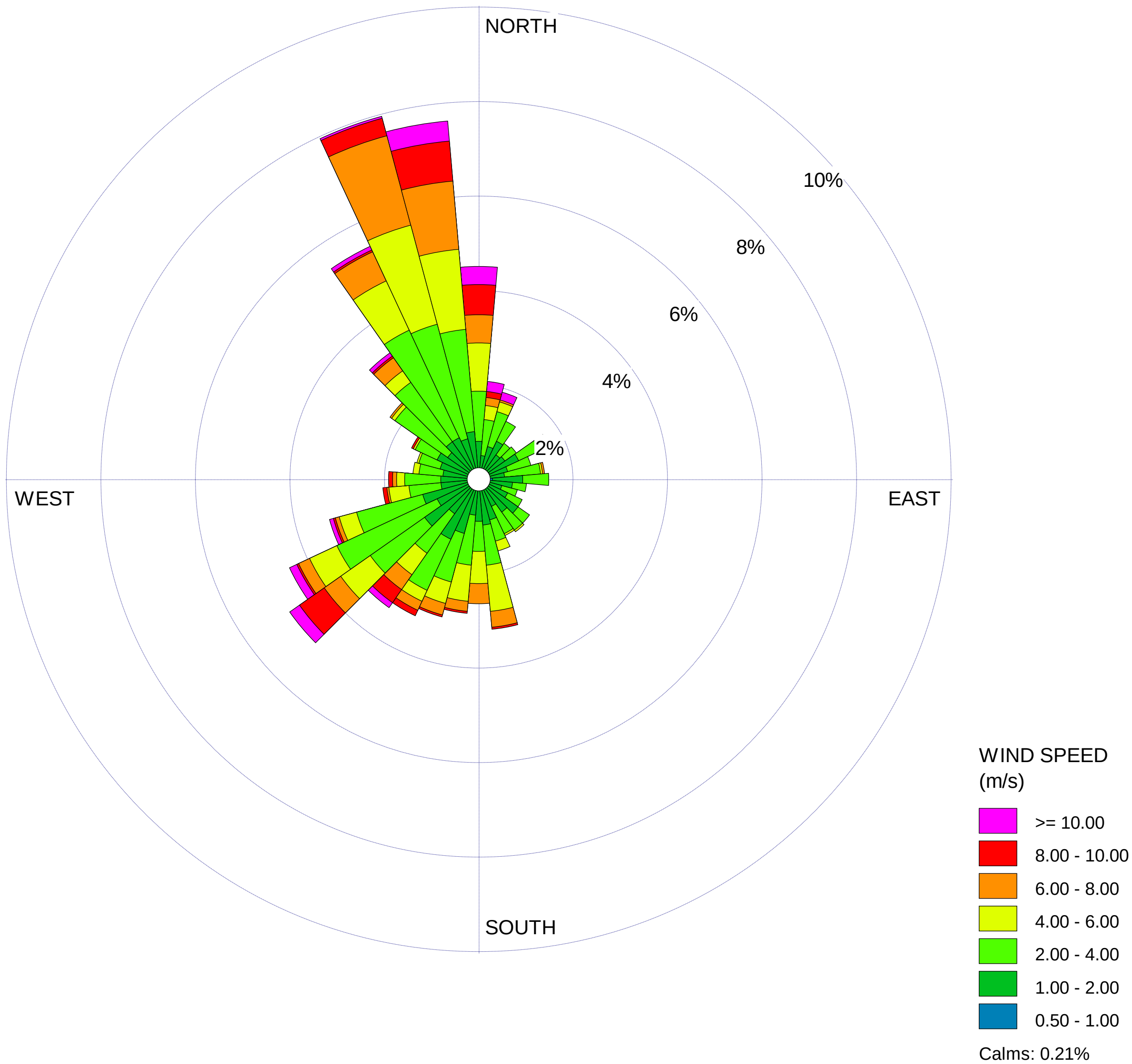
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2009 (1st Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 1/1/2009 - 00:00
End Date: 3/31/2009 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.21%

TOTAL COUNT:

2159 hrs.

AVG. WIND SPEED:

3.42 m/s

DATE:

8/5/2014

PROJECT NO.:

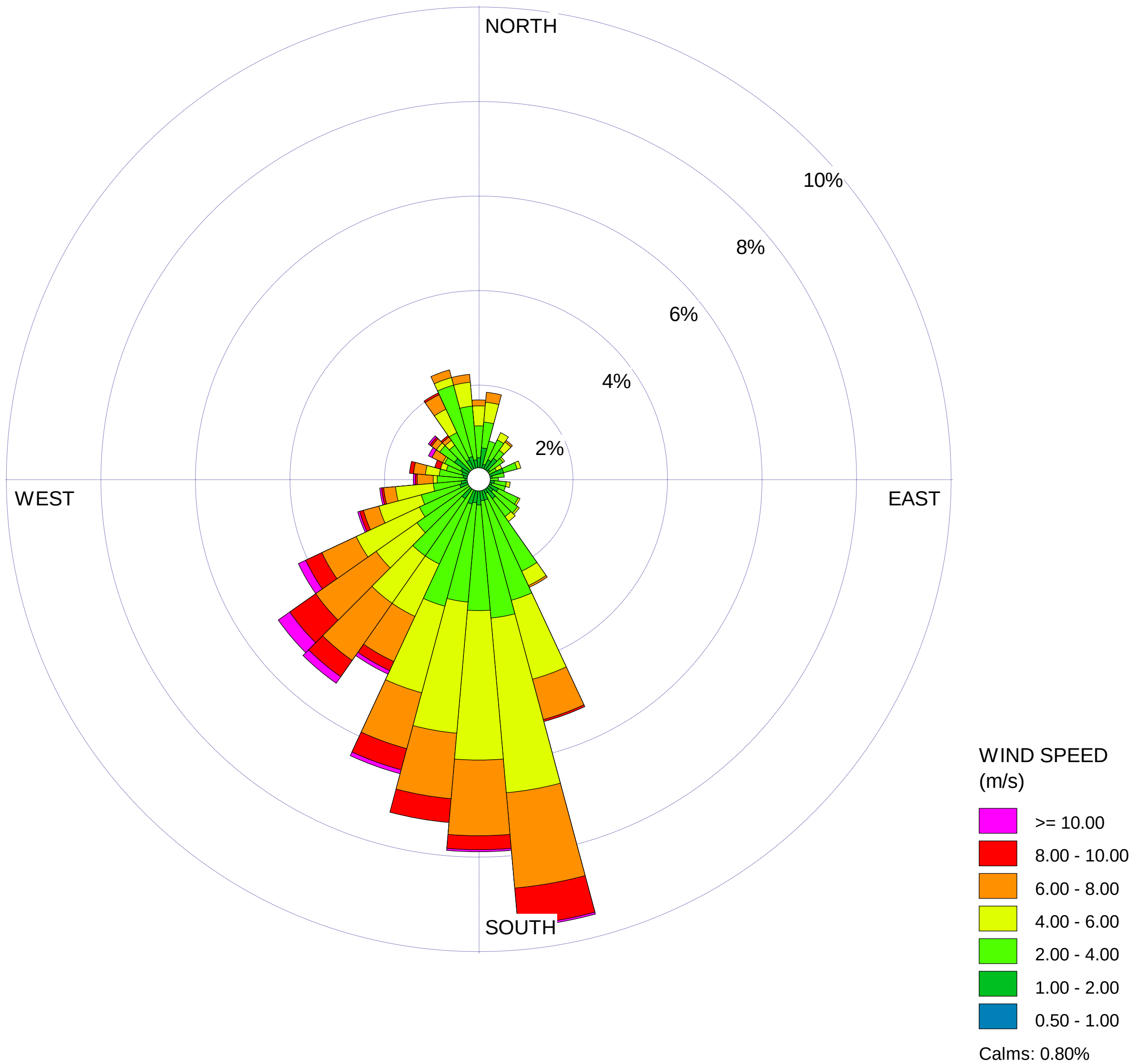
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2009 (2nd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 4/1/2009 - 00:00** **End Date: 6/30/2009 - 23:00**	MODELER:	
	CALM WINDS: **0.80%**	TOTAL COUNT: **2180 hrs.**	
	AVG. WIND SPEED: **4.22 m/s**	DATE: **8/5/2014**	PROJECT NO.:

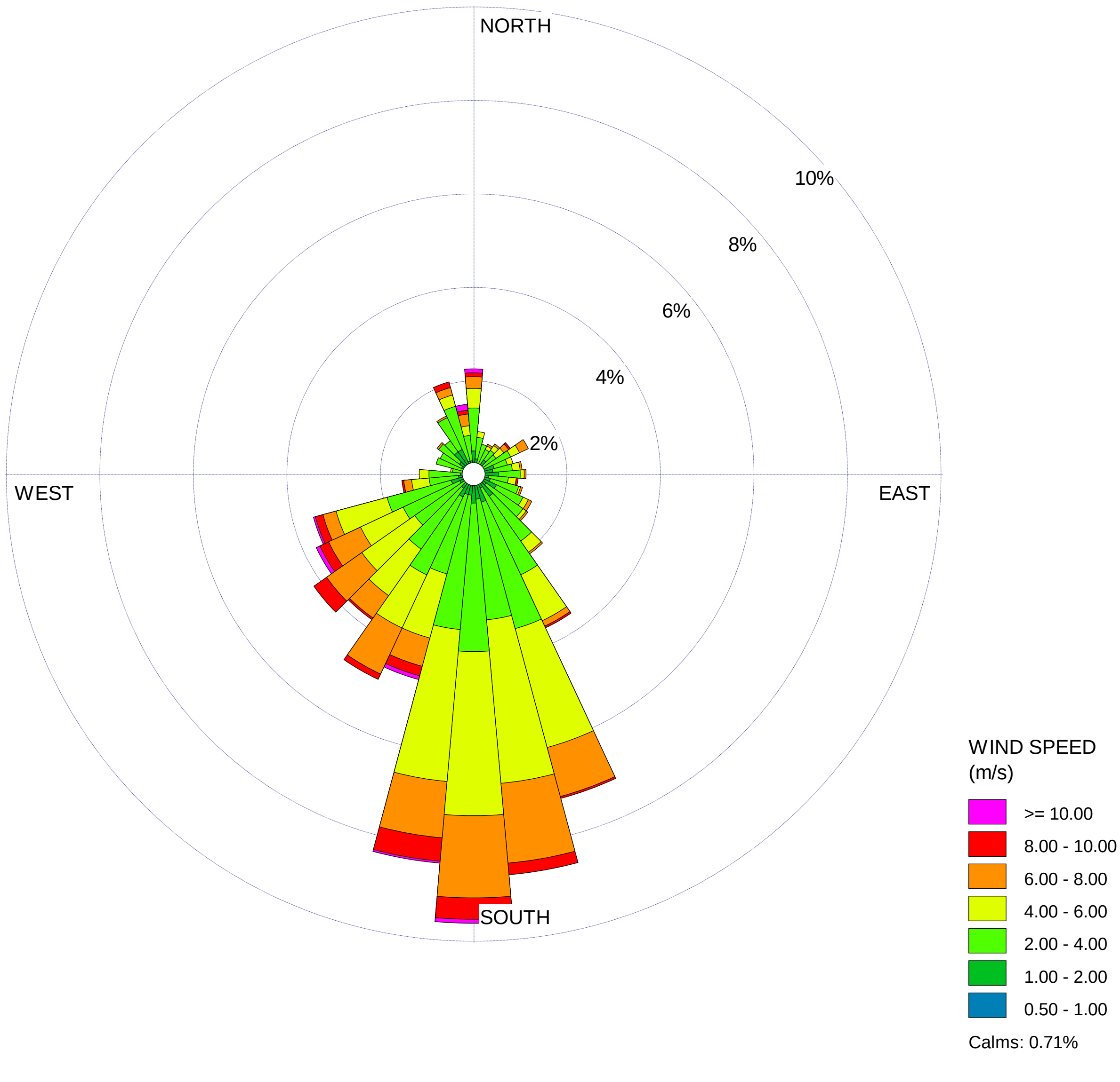
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2009 (3rd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



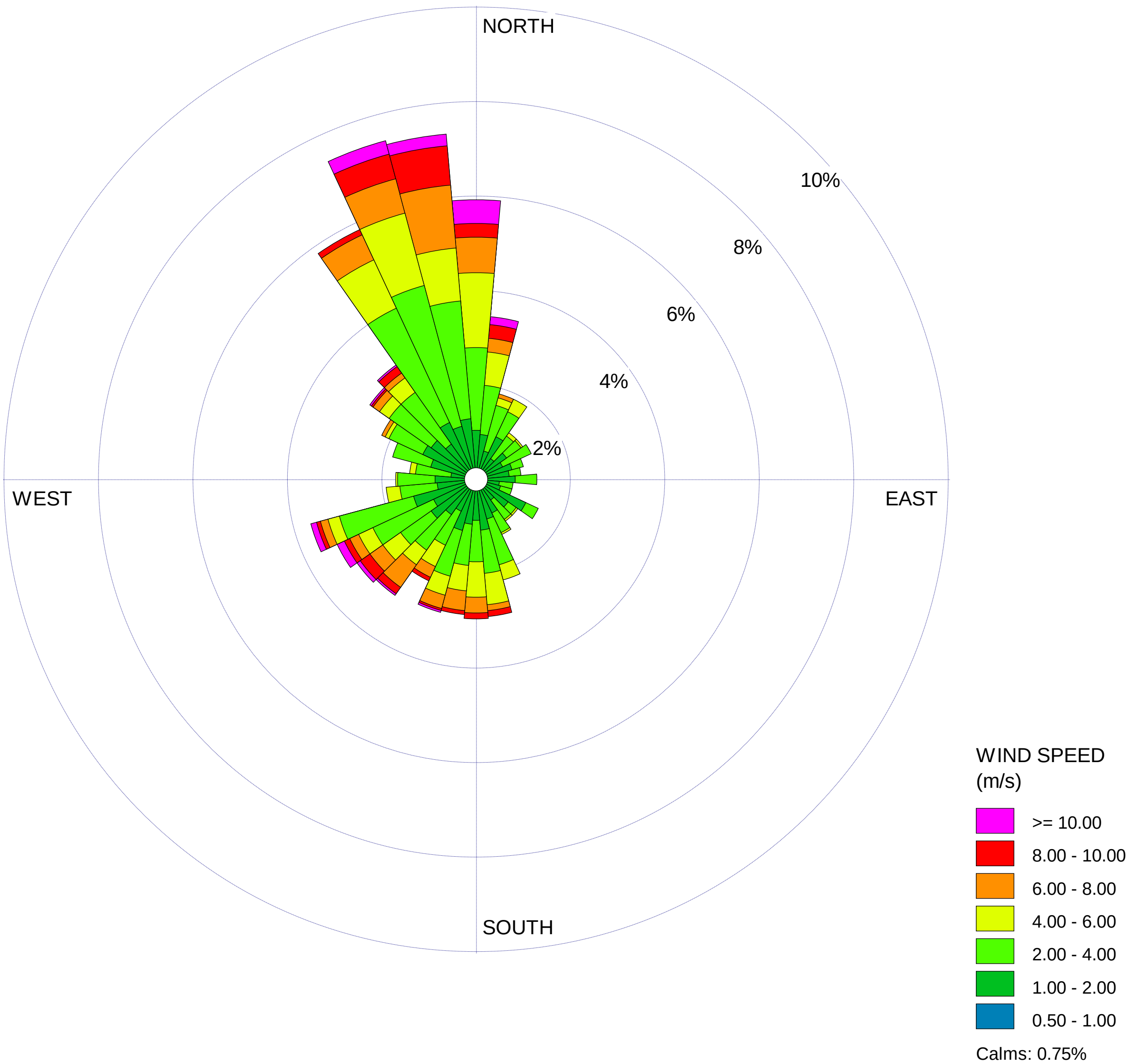
COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 7/1/2009 - 00:00** **End Date: 9/30/2009 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.71%**	TOTAL COUNT: **2201 hrs.**	
	AVG. WIND SPEED: **3.96 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2009 (4th Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 10/1/2009 - 00:00
End Date: 12/31/2009 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.75%

TOTAL COUNT:

2207 hrs.

AVG. WIND SPEED:

3.30 m/s

DATE:

8/5/2014

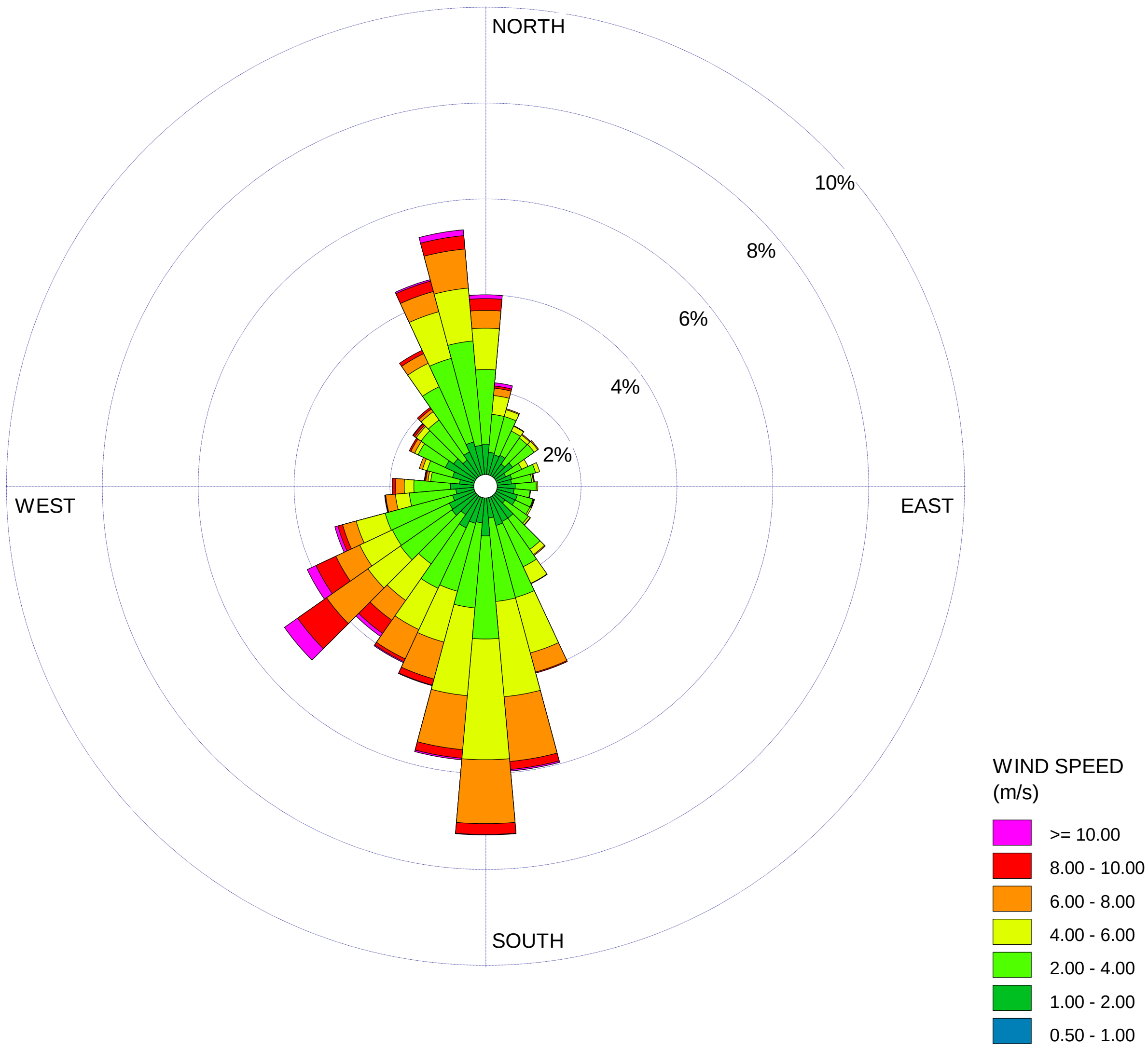
PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2010 (All Year)

DISPLAY:

Wind Speed
Direction (blowing from)



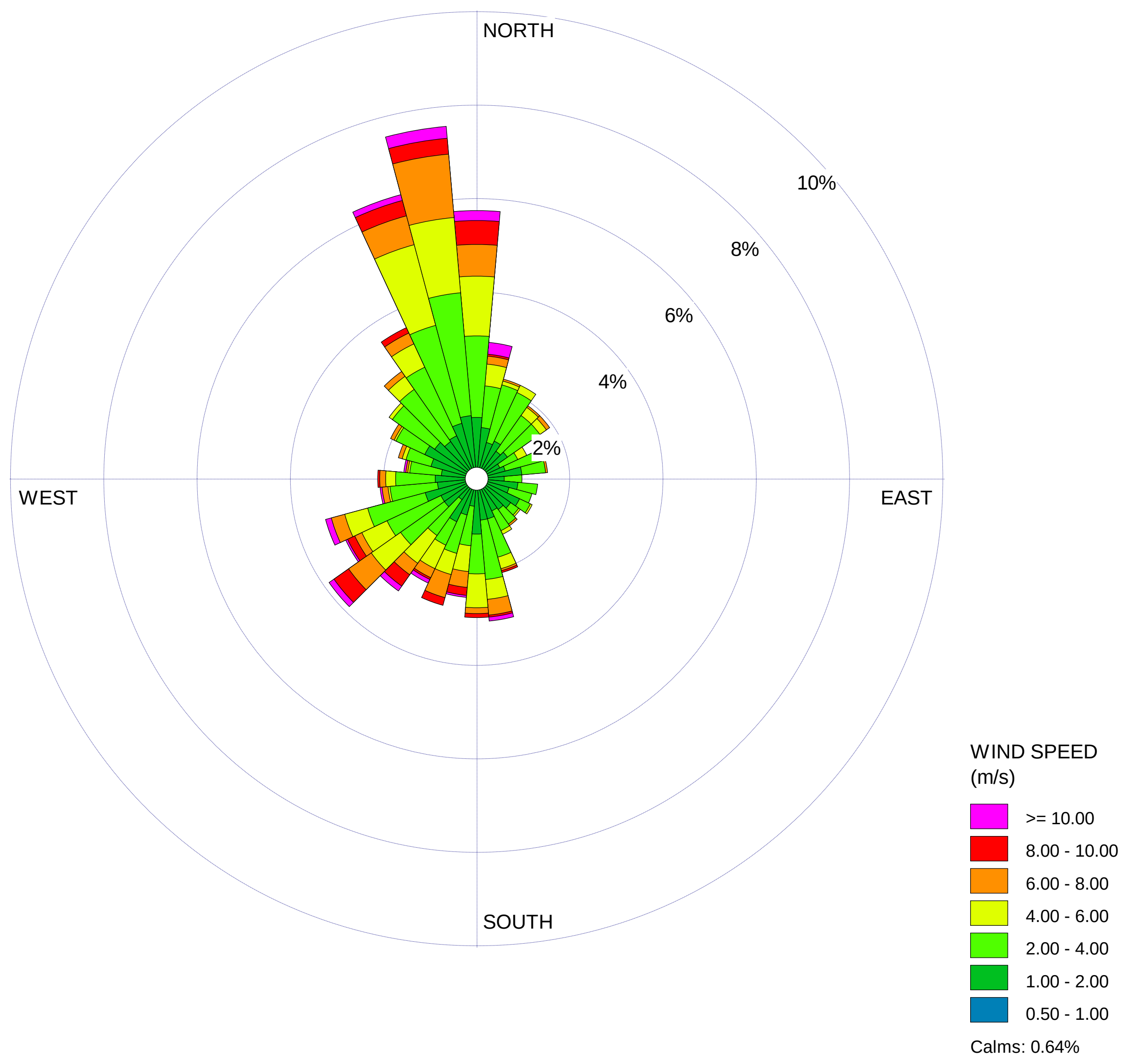
COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 1/1/2010 - 00:00** **End Date: 12/31/2010 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.41%**	TOTAL COUNT: **8753 hrs.**	
	AVG. WIND SPEED: **3.62 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2010 (1st Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 1/1/2010 - 00:00** **End Date: 3/31/2010 - 23:00**		
		MODELER:	
	CALM WINDS: **0.64%**	TOTAL COUNT: **2159 hrs.**	
	AVG. WIND SPEED: **3.22 m/s**	DATE: **8/5/2014**	PROJECT NO.:

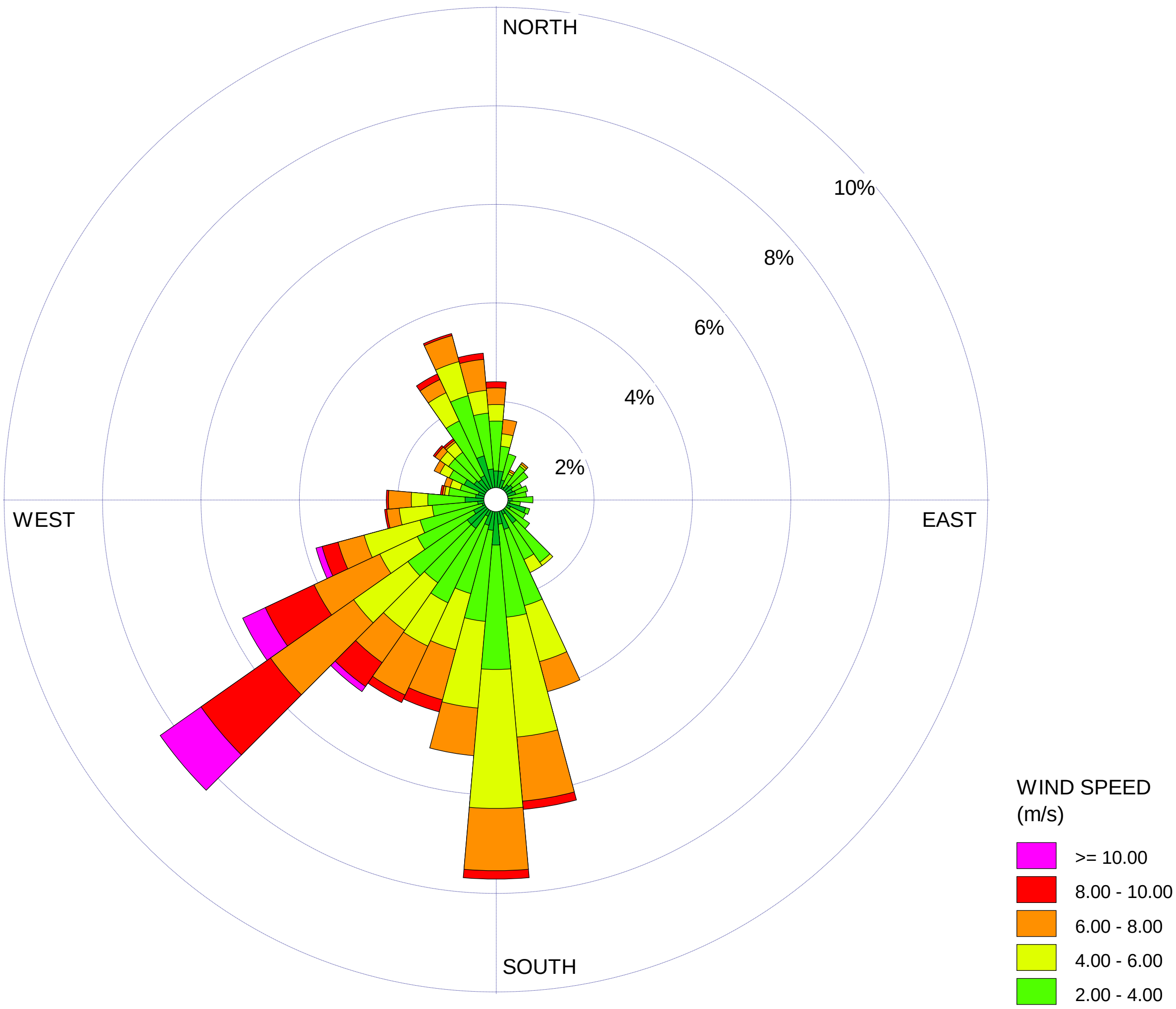
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2010 (2nd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 4/1/2010 - 00:00** **End Date: 6/30/2010 - 23:00**		
		MODELER:	
	CALM WINDS: **0.46%**	TOTAL COUNT: **2183 hrs.**	
	AVG. WIND SPEED: **4.18 m/s**	DATE: **8/5/2014**	PROJECT NO.:

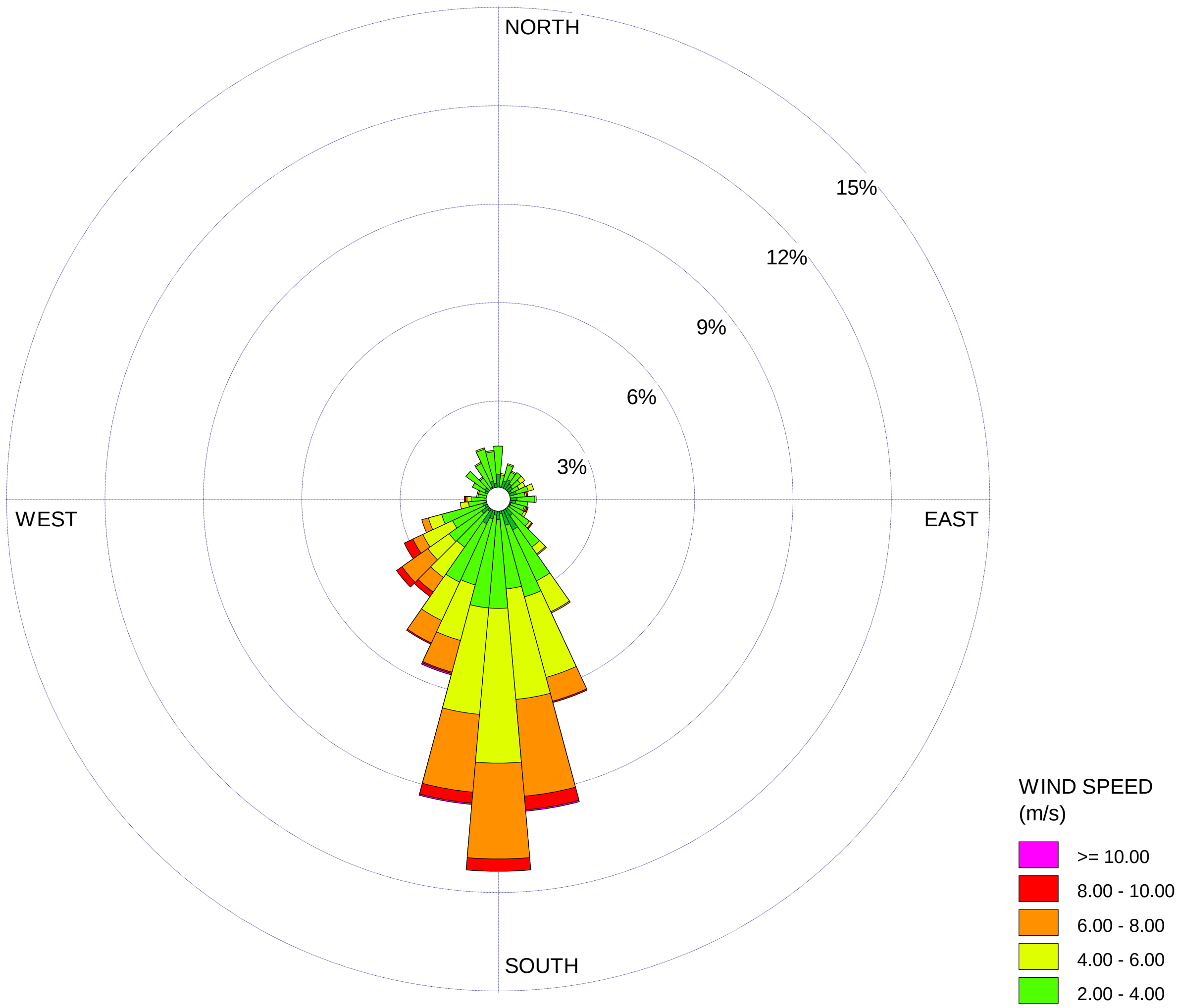
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2010 (3rd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 7/1/2010 - 00:00
End Date: 9/30/2010 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.33%

TOTAL COUNT:

2205 hrs.

AVG. WIND SPEED:

3.83 m/s

DATE:

8/5/2014

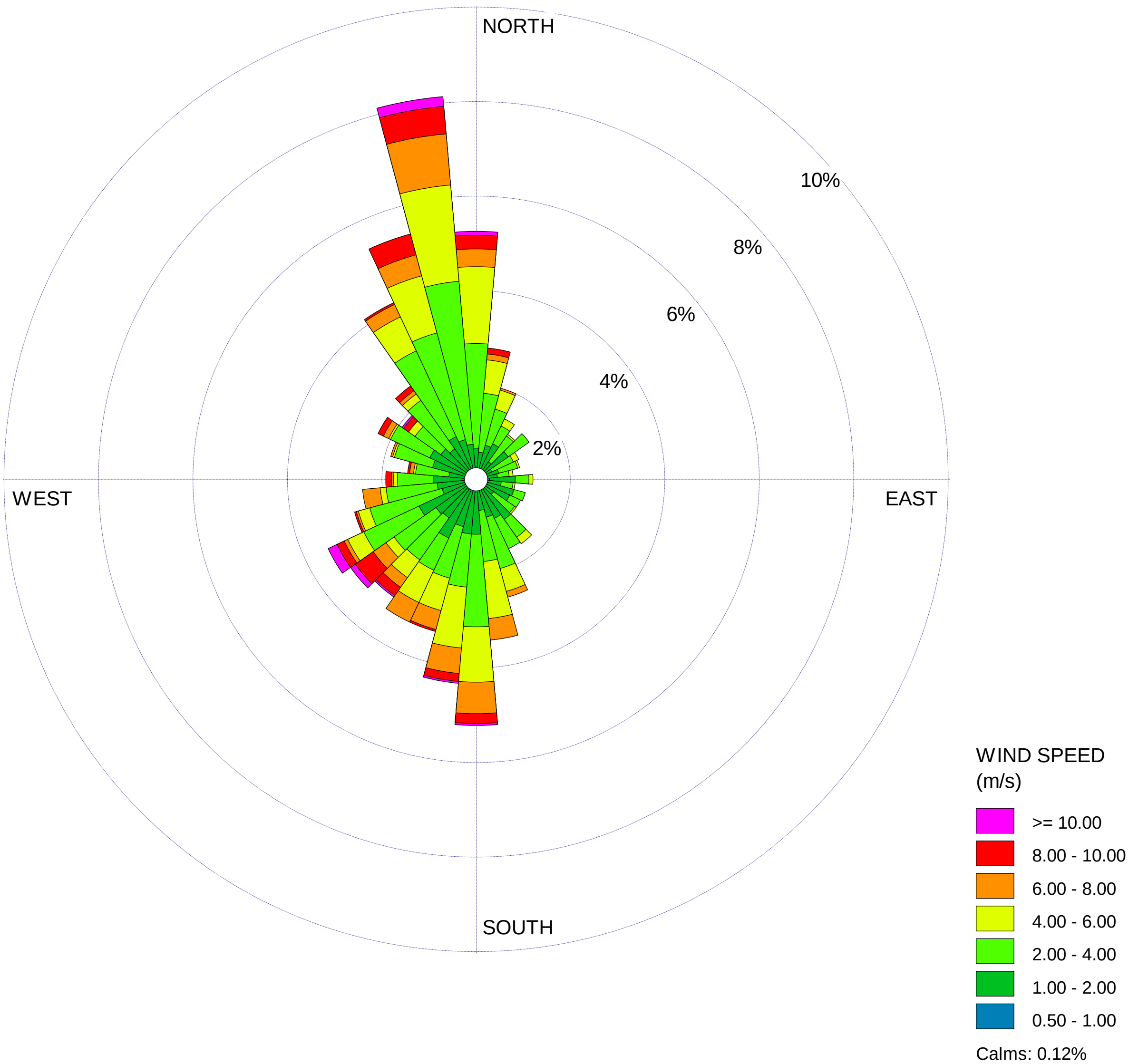
PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2010 (4th Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 10/1/2010 - 00:00** **End Date: 12/31/2010 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.12%**	TOTAL COUNT: **2206 hrs.**	
	AVG. WIND SPEED: **3.26 m/s**	DATE: **8/5/2014**	PROJECT NO.:

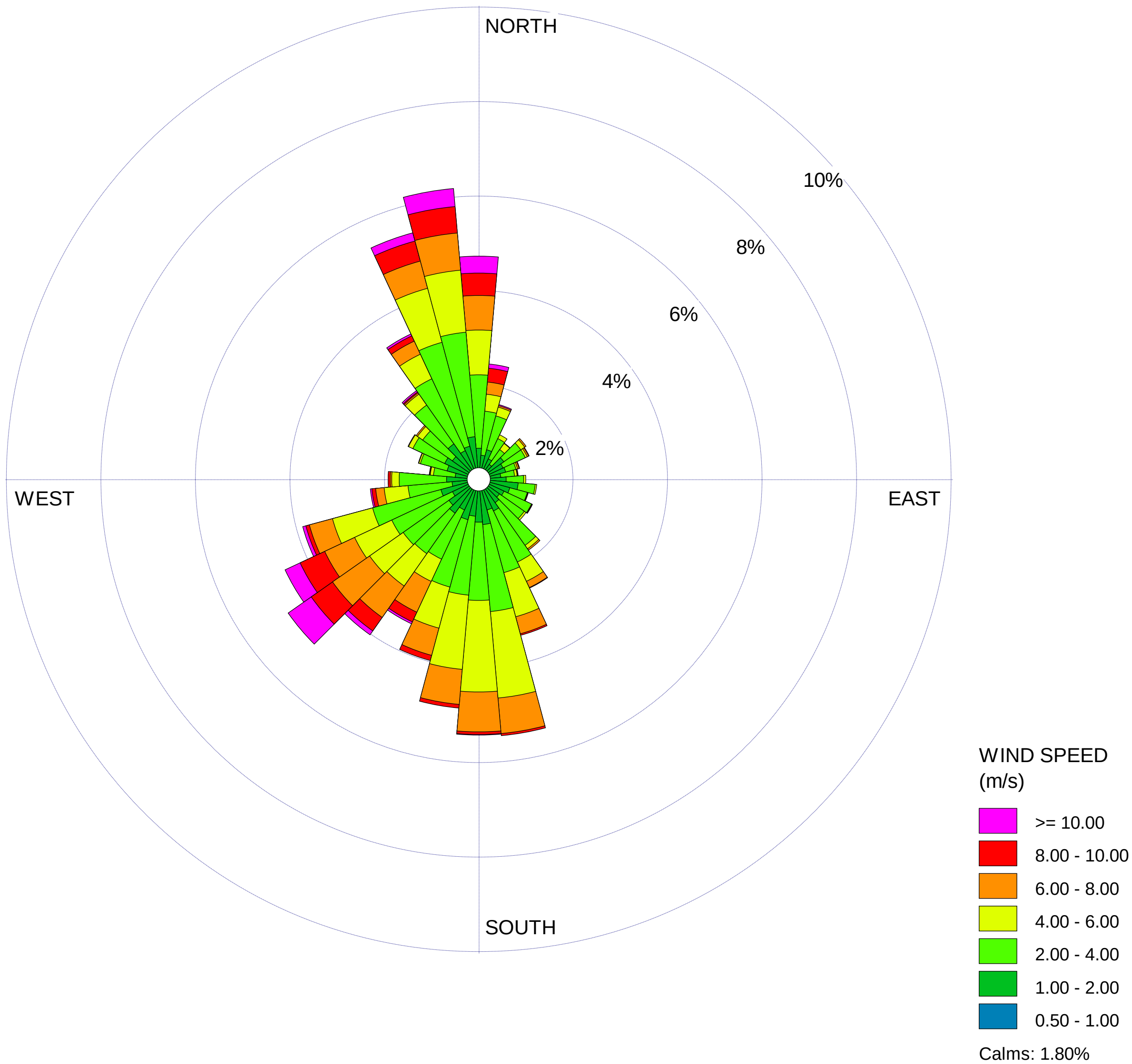
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2011 (All Year)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 1/1/2011 - 00:00
End Date: 12/31/2011 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

1.80%

TOTAL COUNT:

8704 hrs.

AVG. WIND SPEED:

3.73 m/s

DATE:

8/5/2014

PROJECT NO.:

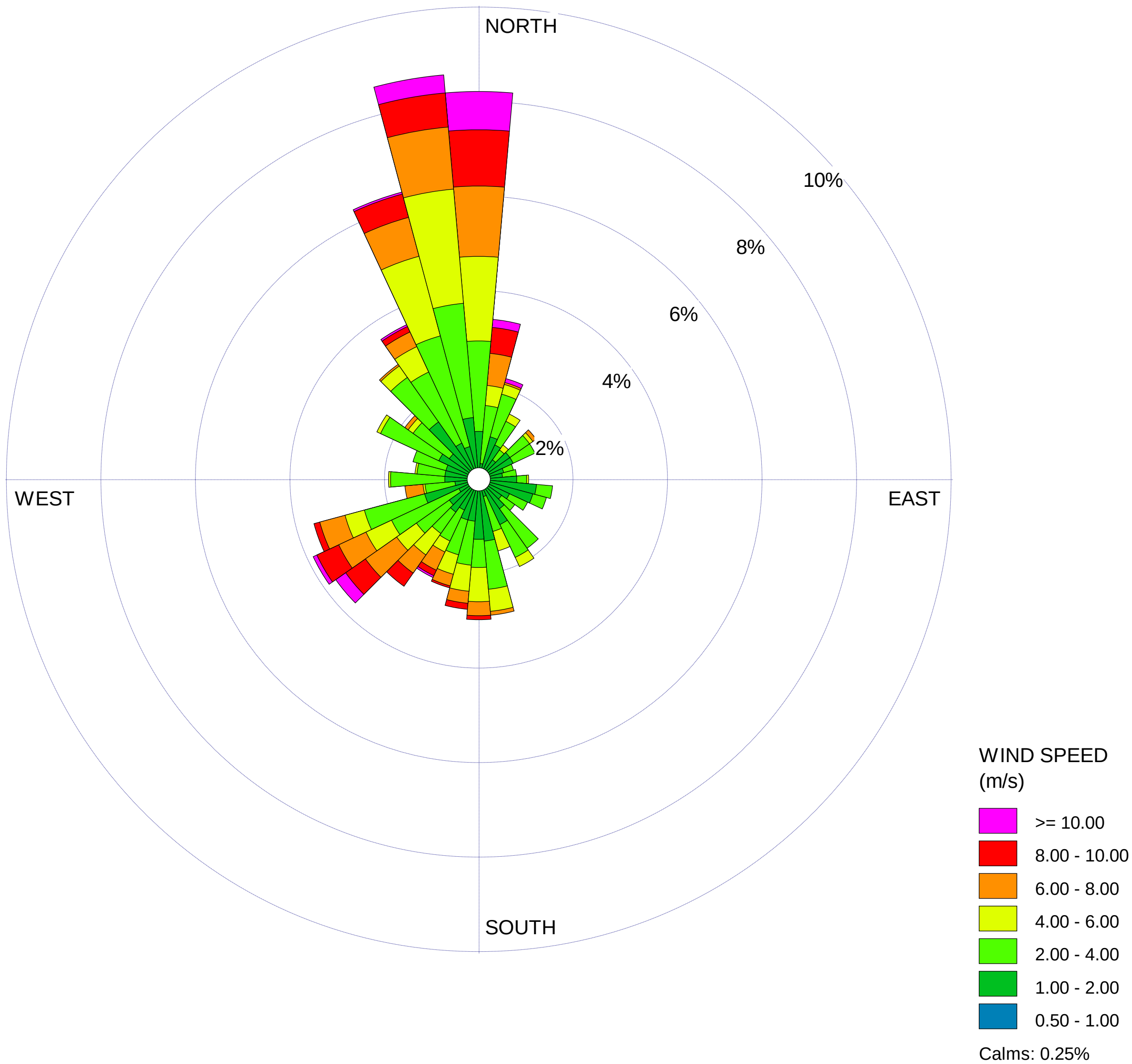
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2011 (1st Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



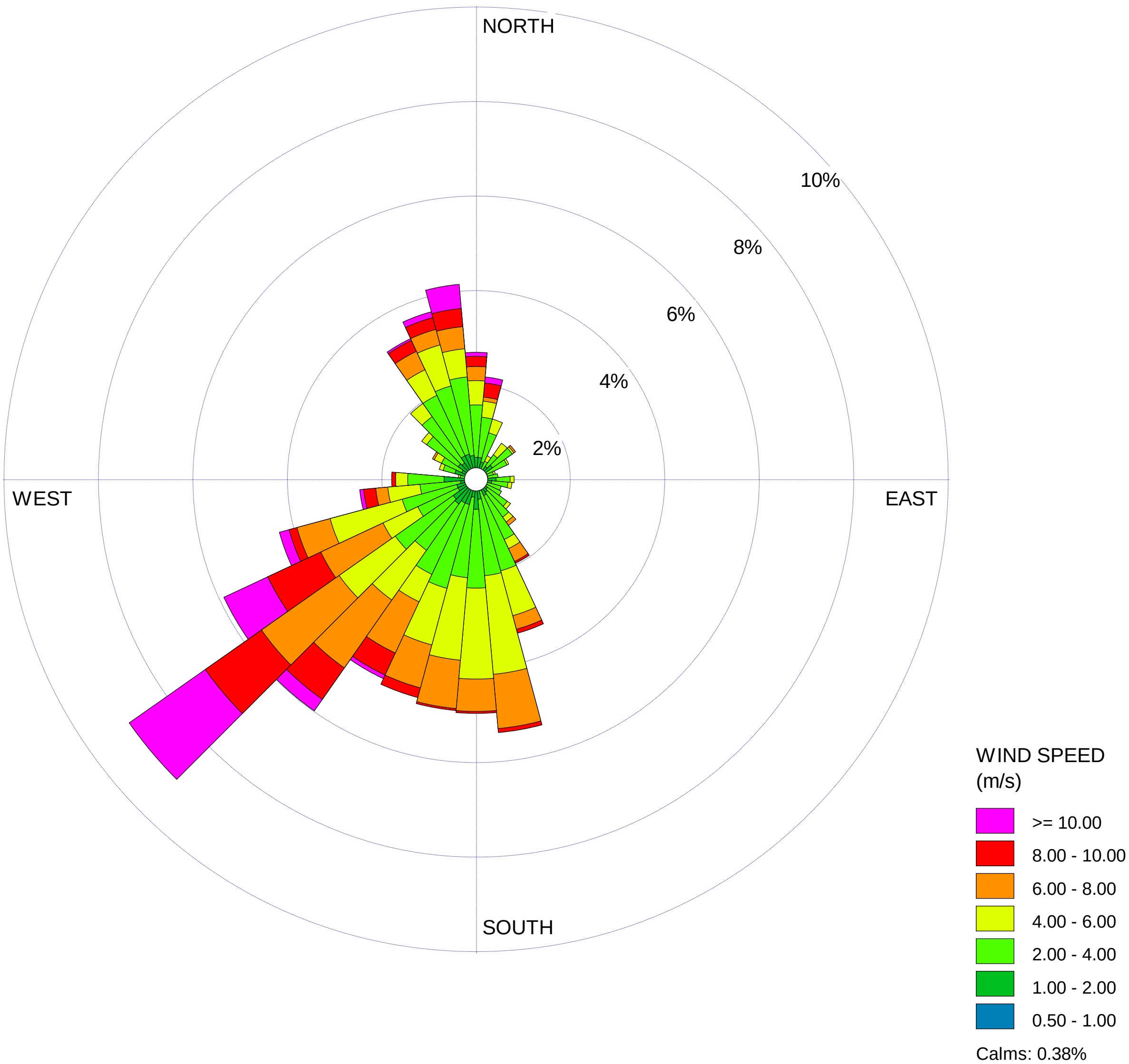
COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 1/1/2011 - 00:00** **End Date: 3/31/2011 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.25%**	TOTAL COUNT: **2159 hrs.**	
	AVG. WIND SPEED: **3.58 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2011 (2nd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 4/1/2011 - 00:00** **End Date: 6/30/2011 - 23:00**		
		MODELER:	
	CALM WINDS: **0.38%**	TOTAL COUNT: **2148 hrs.**	
	AVG. WIND SPEED: **4.57 m/s**	DATE: **8/5/2014**	PROJECT NO.:

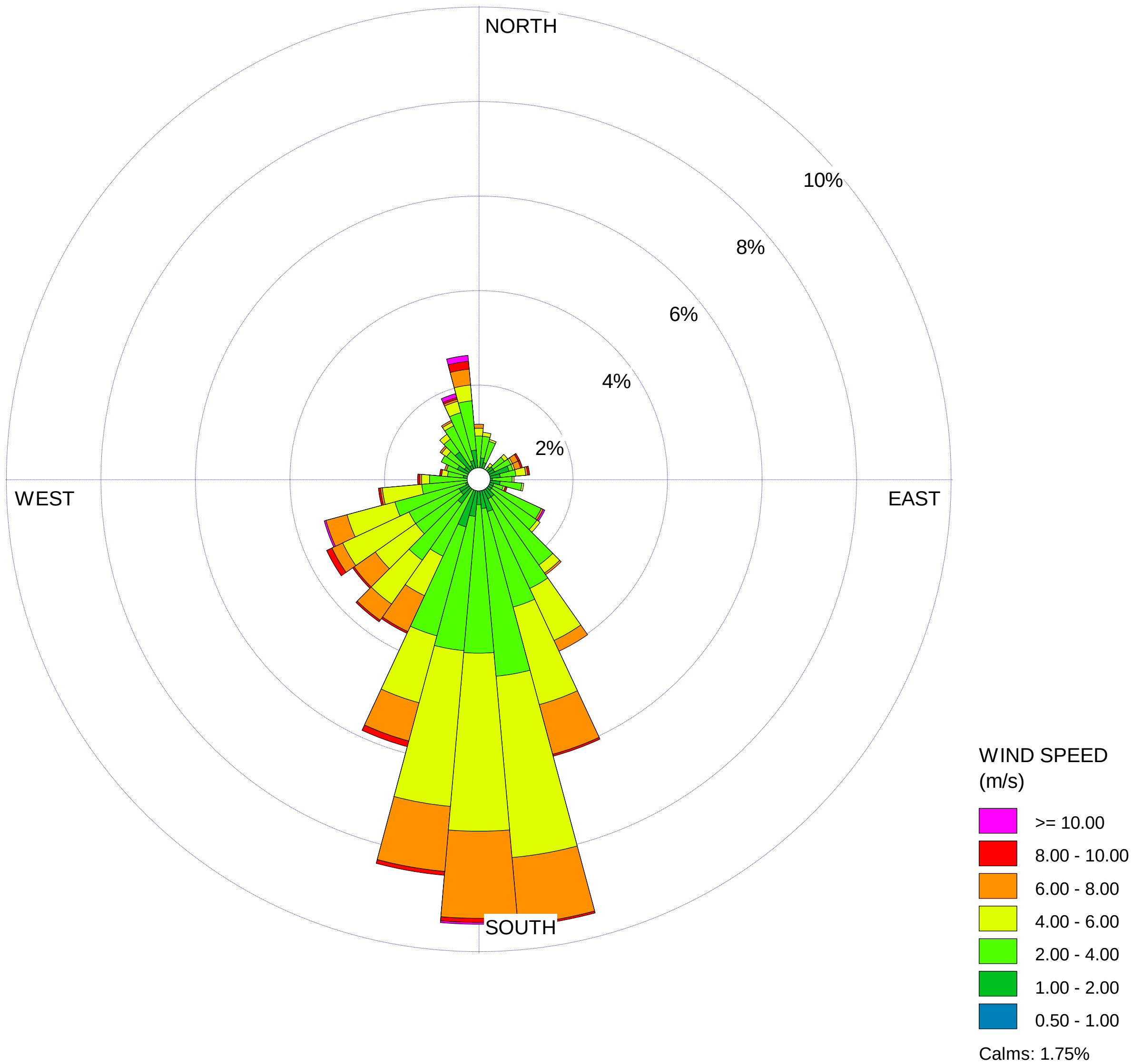
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2011 (3rd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 7/1/2011 - 00:00
End Date: 9/30/2011 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

1.75%

TOTAL COUNT:

2197 hrs.

AVG. WIND SPEED:

3.71 m/s

DATE:

8/5/2014

PROJECT NO.:

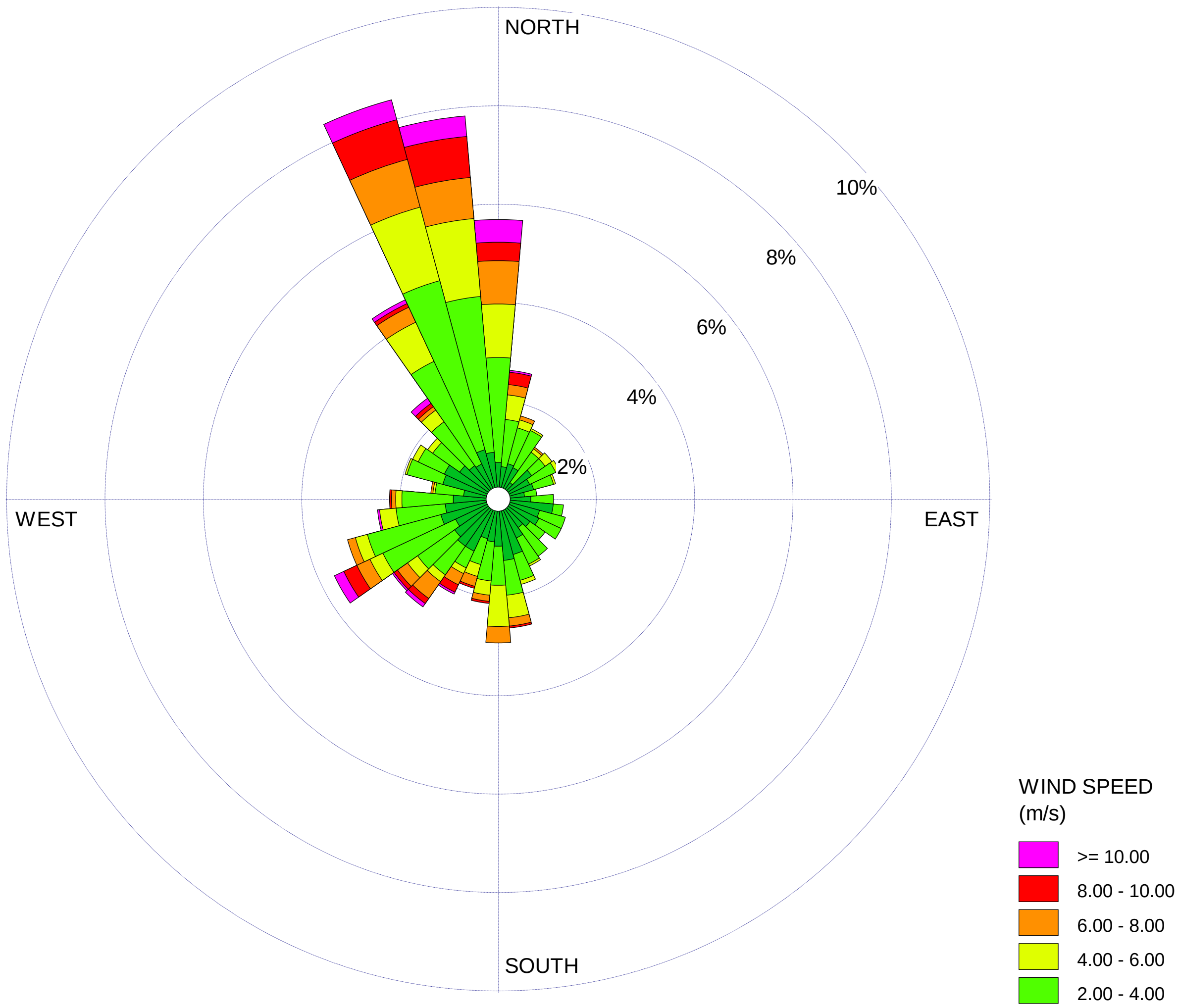
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2011 (4th Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



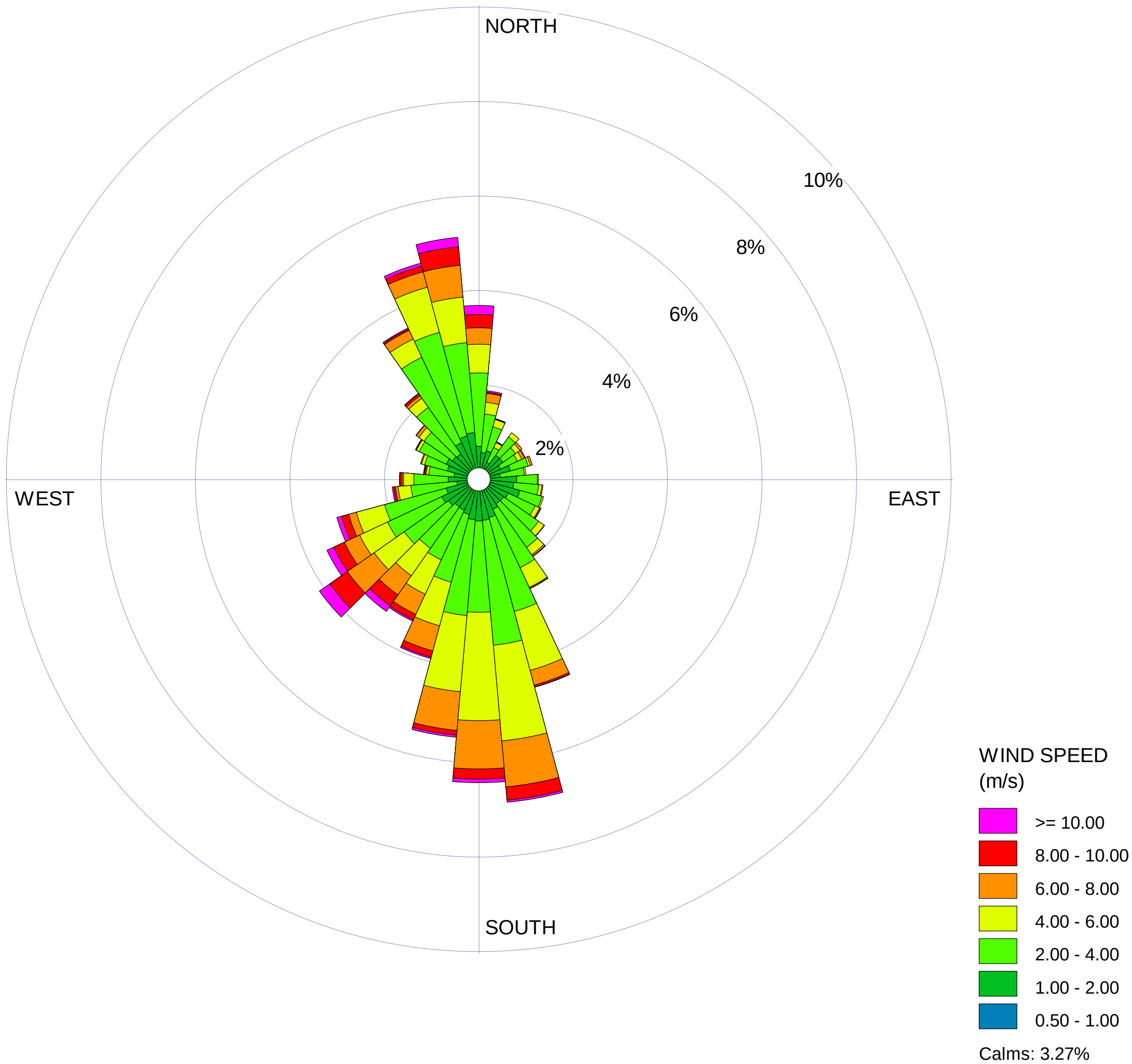
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 10/1/2011 - 00:00** **End Date: 12/31/2011 - 23:00**	MODELER:	
	CALM WINDS: **4.30%**	TOTAL COUNT: **2200 hrs.**	
	AVG. WIND SPEED: **3.08 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2012 (All Year)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 1/1/2012 - 00:00
End Date: 12/31/2012 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

3.27%

TOTAL COUNT:

8725 hrs.

AVG. WIND SPEED:

3.44 m/s

DATE:

8/5/2014

PROJECT NO.:

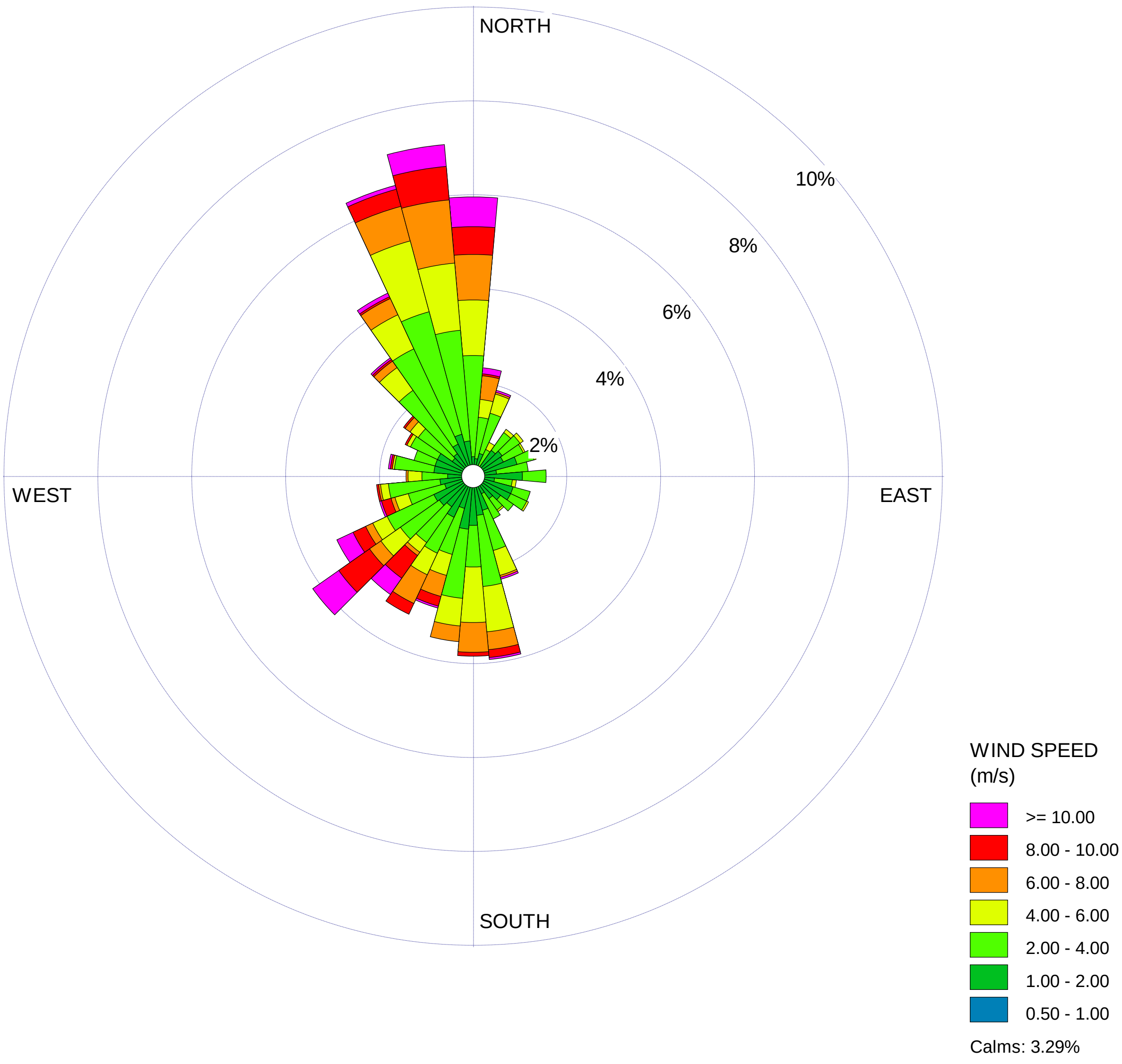
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2012 (1st Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 1/1/2012 - 00:00** **End Date: 3/31/2012 - 23:00**		
		MODELER:	
	CALM WINDS: **3.29%**	TOTAL COUNT: **2177 hrs.**	
	AVG. WIND SPEED: **3.61 m/s**	DATE: **8/5/2014**	PROJECT NO.:

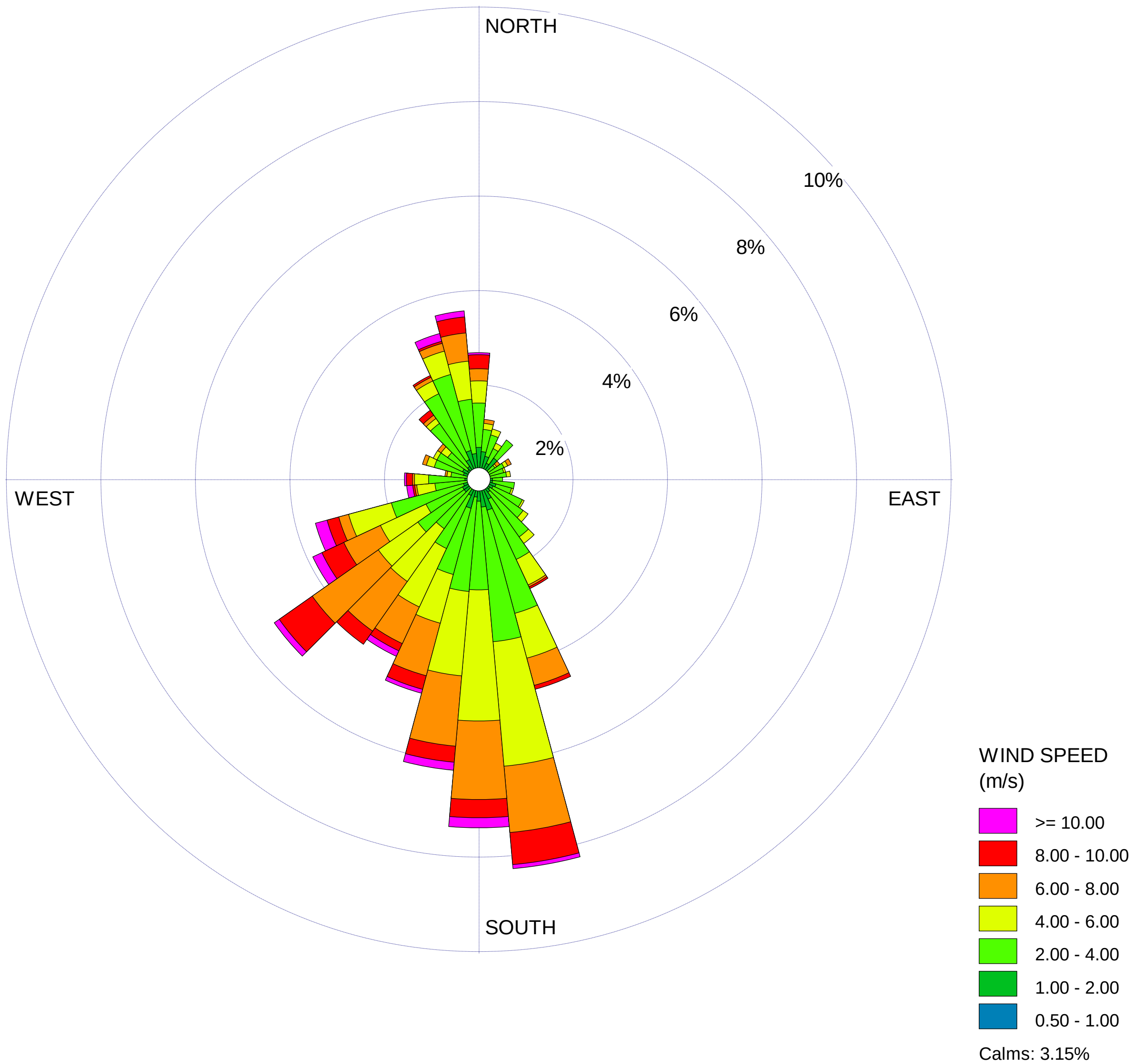
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2012 (2nd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 4/1/2012 - 00:00
End Date: 6/30/2012 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

3.15%

TOTAL COUNT:

2153 hrs.

AVG. WIND SPEED:

4.11 m/s

DATE:

8/5/2014

PROJECT NO.:

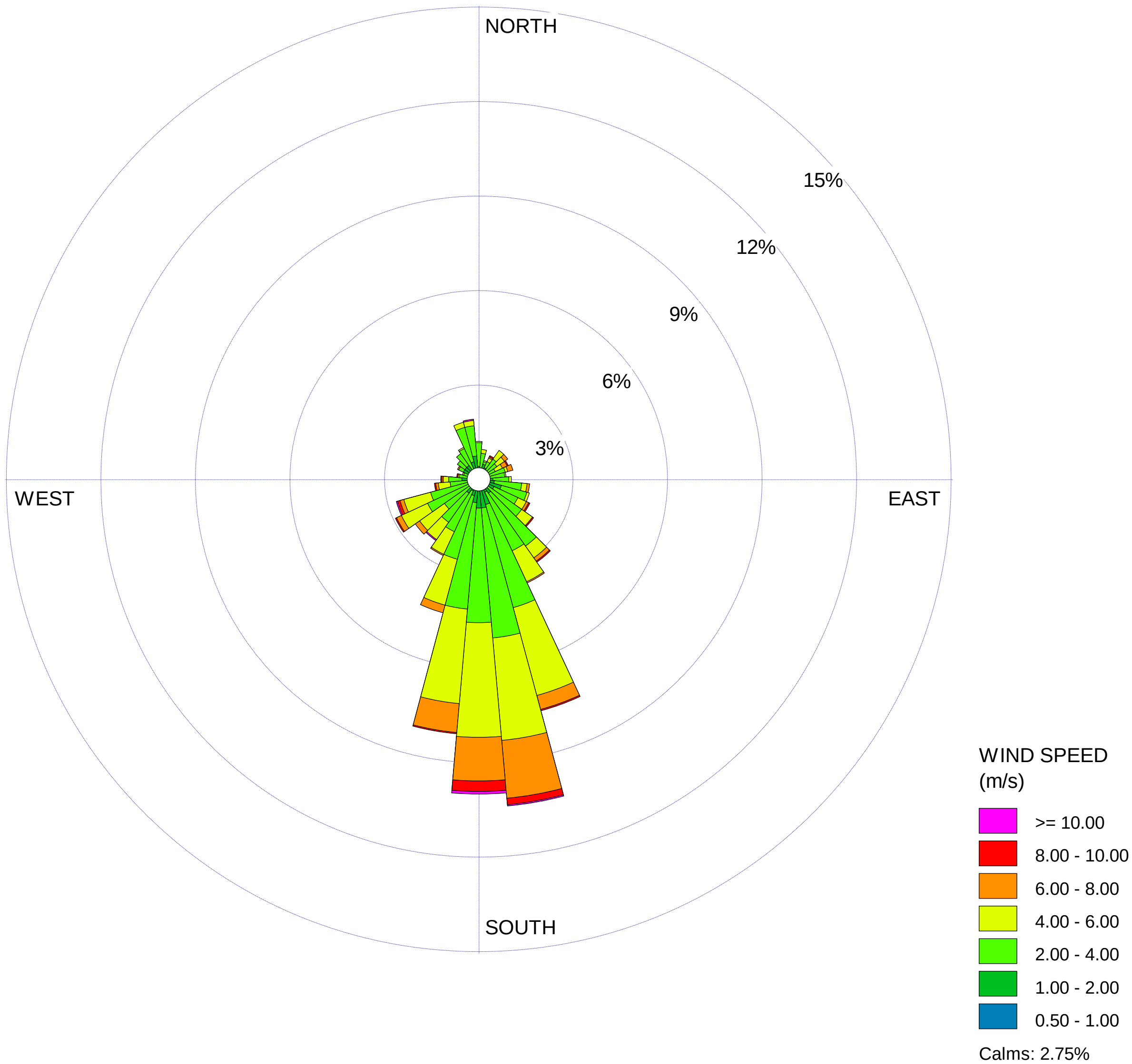
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2012 (3rd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 7/1/2012 - 00:00
End Date: 9/30/2012 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

2.75%

TOTAL COUNT:

2199 hrs.

AVG. WIND SPEED:

3.43 m/s

DATE:

8/5/2014

PROJECT NO.:

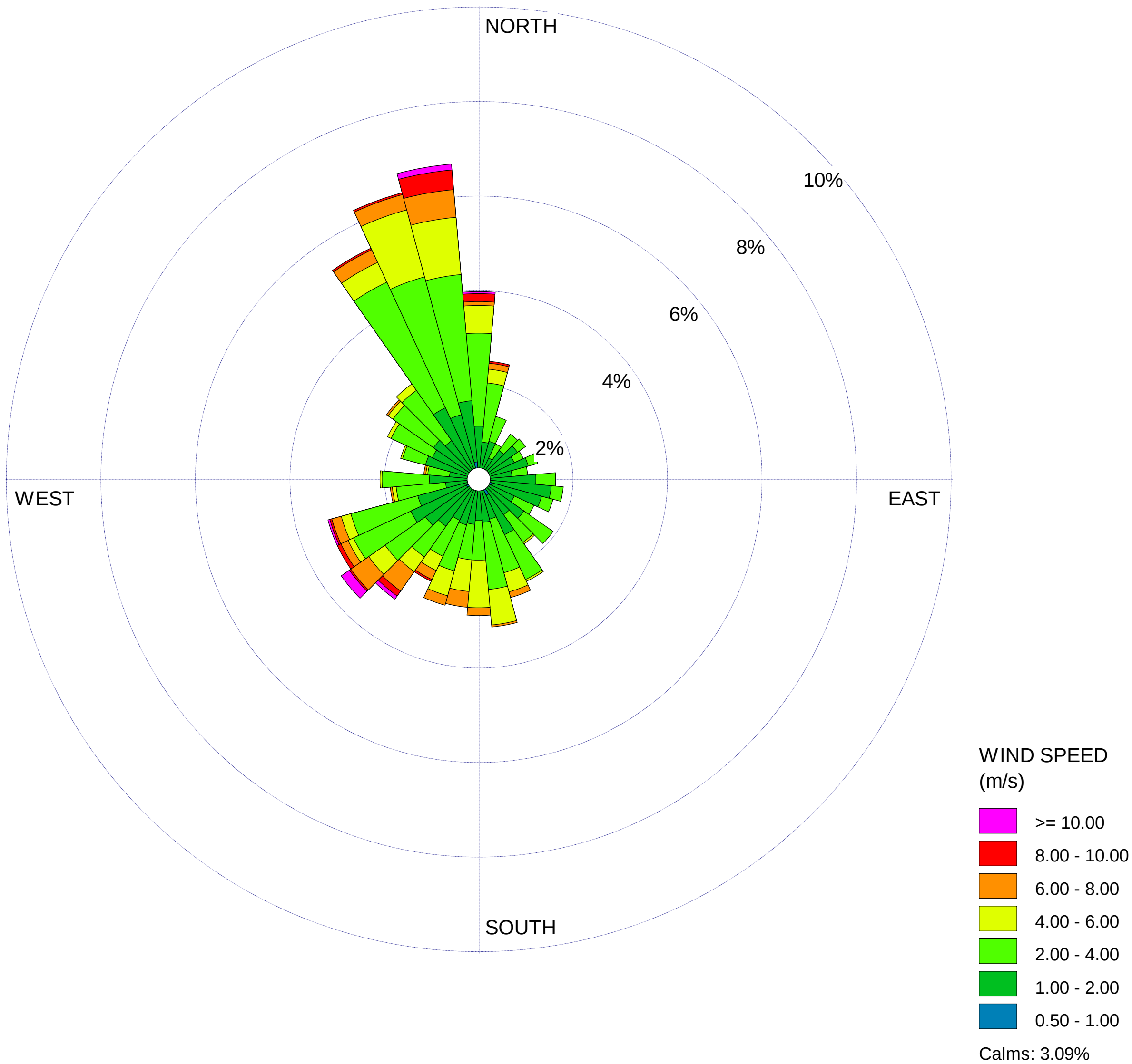
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2012 (4th Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



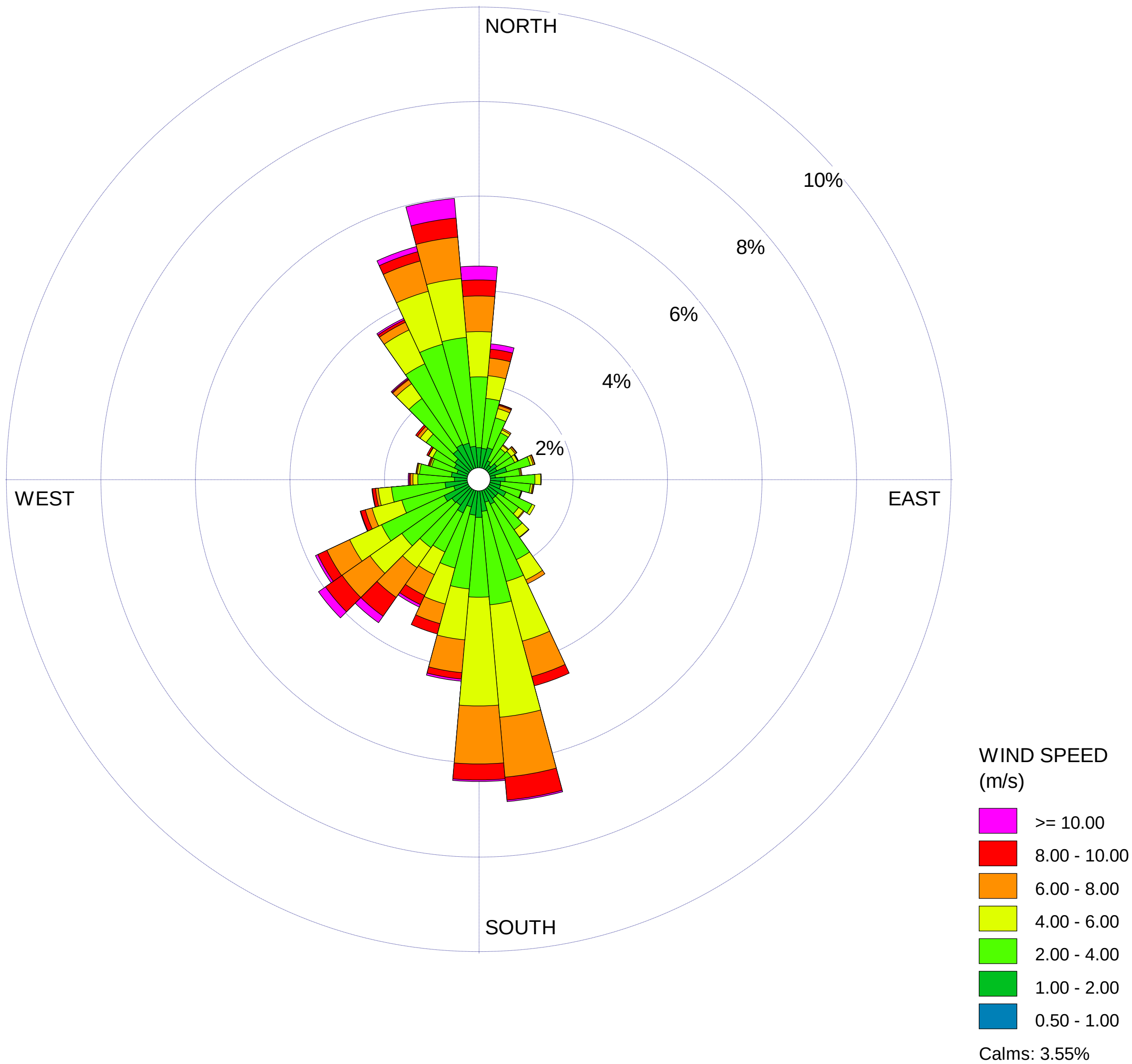
COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 10/1/2012 - 00:00** **End Date: 12/31/2012 - 23:00**	MODELER:	
	CALM WINDS: **3.09%**	TOTAL COUNT: **2196 hrs.**	
	AVG. WIND SPEED: **2.61 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2013 (All Year)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:	DATA PERIOD:	COMPANY NAME:	
Marc Valdez - Sierra Research	**Start Date: 1/1/2013 - 00:00** **End Date: 12/31/2013 - 16:00**		
		MODELER:	
	CALM WINDS: **3.55%**	TOTAL COUNT: **8698 hrs.**	
	AVG. WIND SPEED: **3.69 m/s**	DATE: **8/5/2014**	PROJECT NO.:

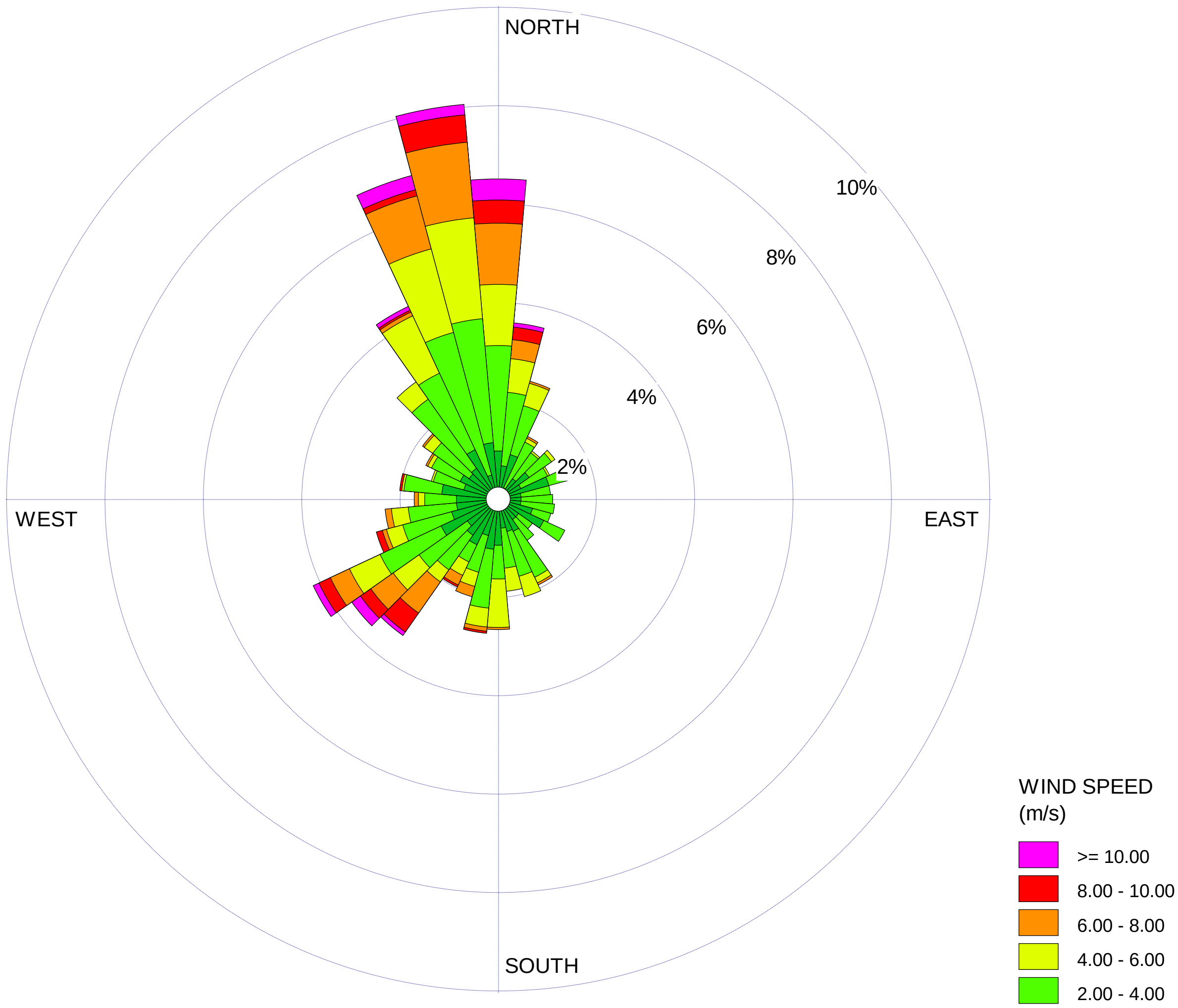
WRPLOT View - Lakes Environmental Software

WIND ROSE PLOT:

Blythe, CA
2013 (1st Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 1/1/2013 - 00:00
End Date: 3/31/2013 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

2.27%

TOTAL COUNT:

2142 hrs.

AVG. WIND SPEED:

3.30 m/s

DATE:

8/5/2014

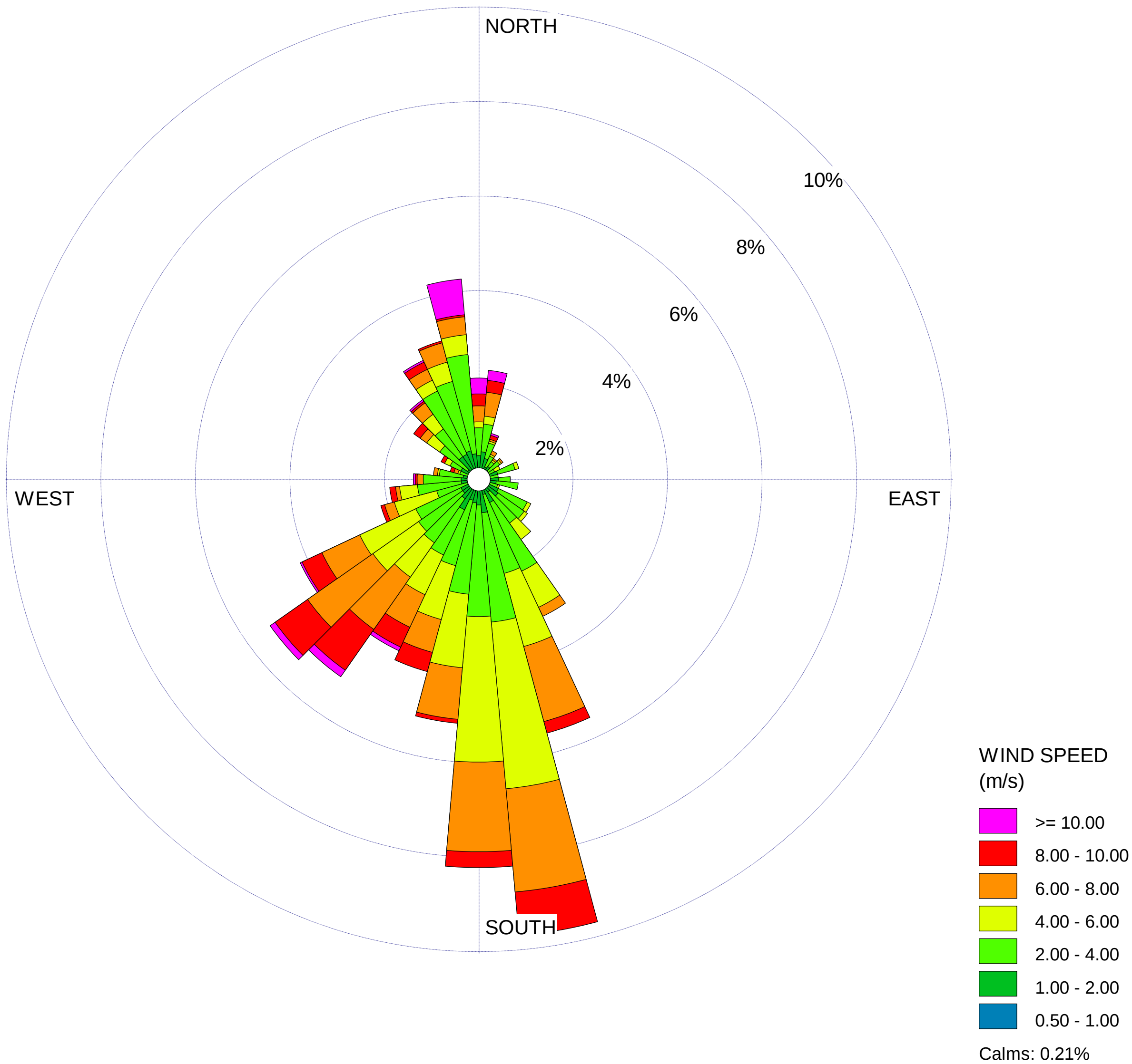
PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2013 (2nd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

Marc Valdez - Sierra Research

DATA PERIOD:

Start Date: 4/1/2013 - 00:00
End Date: 6/30/2013 - 23:00

COMPANY NAME:

MODELER:

CALM WINDS:

0.21%

TOTAL COUNT:

2180 hrs.

AVG. WIND SPEED:

4.39 m/s

DATE:

8/5/2014

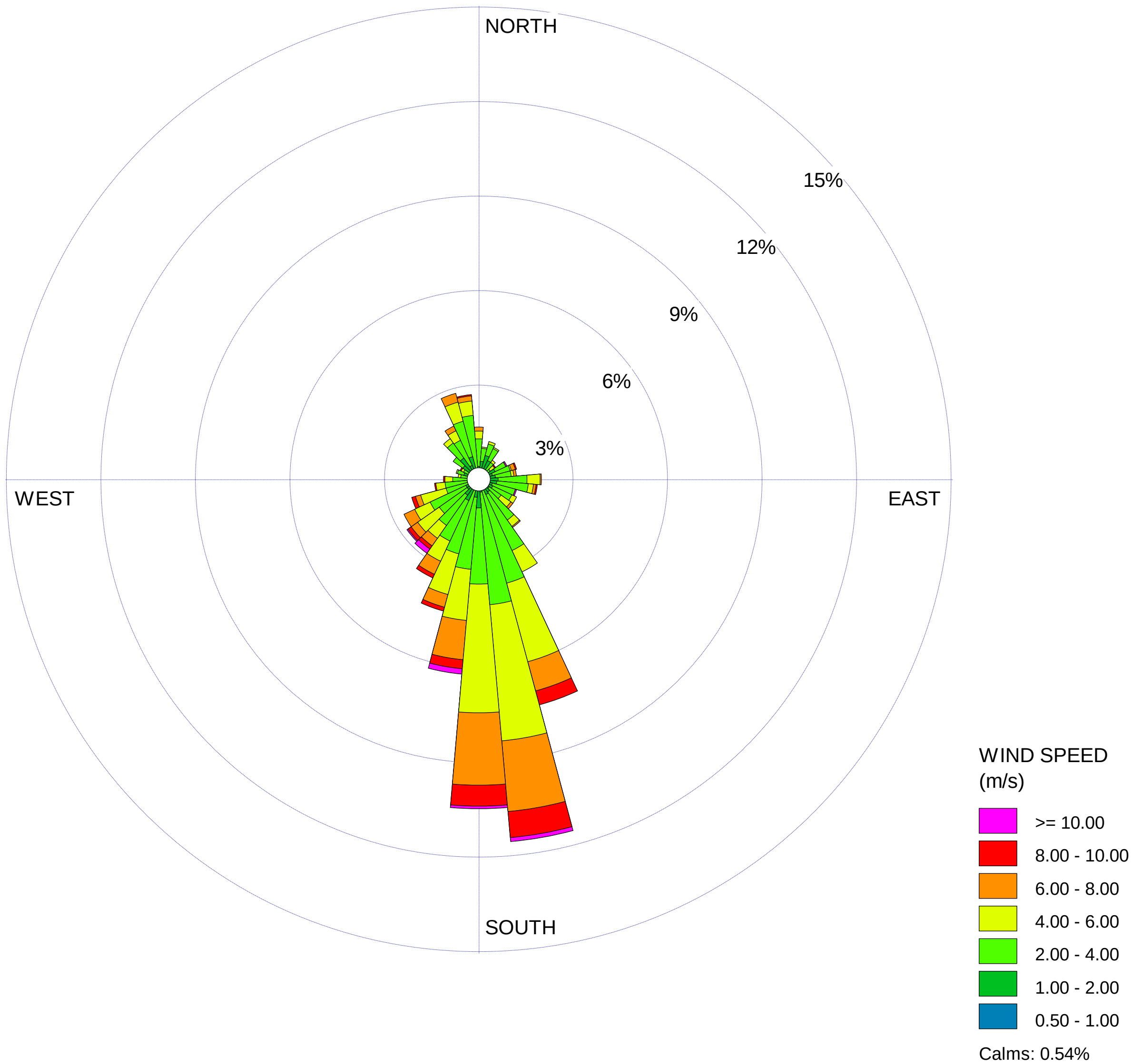
PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2013 (3rd Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



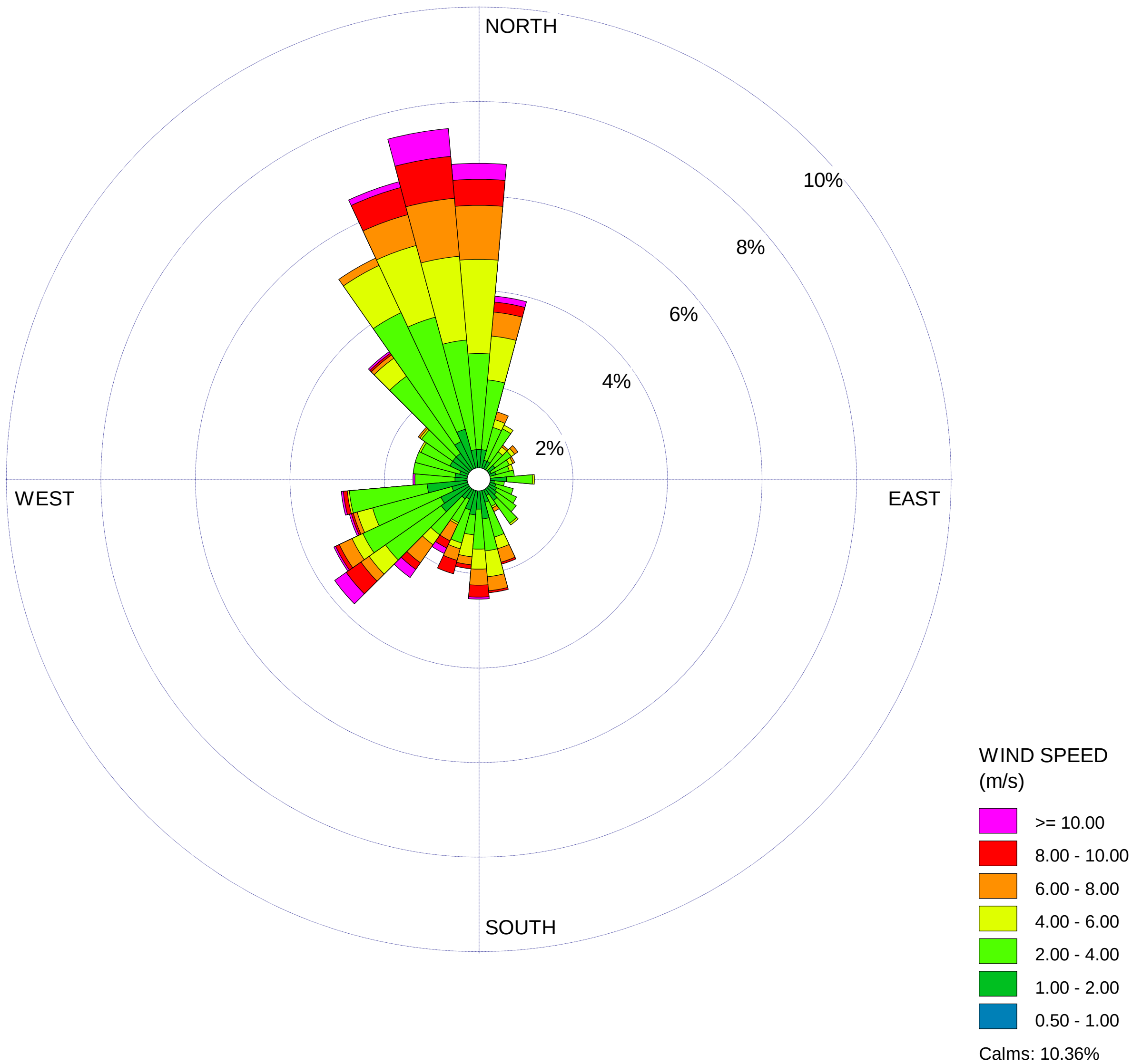
COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 7/1/2013 - 00:00** **End Date: 9/30/2013 - 23:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **0.54%**	TOTAL COUNT: **2207 hrs.**	
	AVG. WIND SPEED: **3.80 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WIND ROSE PLOT:

Blythe, CA
2013 (4th Quarter)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS: Marc Valdez - Sierra Research	DATA PERIOD: **Start Date: 10/1/2013 - 00:00** **End Date: 12/31/2013 - 16:00**	COMPANY NAME:	
		MODELER:	
	CALM WINDS: **10.36%**	TOTAL COUNT: **2169 hrs.**	
	AVG. WIND SPEED: **3.27 m/s**	DATE: **8/5/2014**	PROJECT NO.:

WRPLOT View - Lakes Environmental Software

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2009 - 2013 (ALL FIVE YEARS)
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	31	297	653	382	237	143	105	1848
5 - 15	26	253	388	169	103	59	36	1034
15 - 25	23	260	309	71	15	2	8	688
25 - 35	29	213	227	47	6	1	0	523
35 - 45	32	193	205	48	7	0	0	485
45 - 55	29	235	184	43	16	2	0	509
55 - 65	23	201	201	44	15	2	1	487
65 - 75	36	243	179	25	10	2	0	495
75 - 85	27	184	196	18	6	2	0	433
85 - 95	31	259	207	22	2	0	0	521
95 - 105	26	257	195	20	4	2	0	504
105 - 115	44	244	183	7	2	2	1	483
115 - 125	33	268	239	22	5	1	1	569
125 - 135	26	231	287	36	3	2	0	585
135 - 145	33	255	402	66	10	1	0	767
145 - 155	44	260	553	193	28	3	0	1081
155 - 165	40	284	752	541	215	28	1	1861
165 - 175	36	322	895	945	488	116	11	2813
175 - 185	40	355	826	998	492	95	15	2821
185 - 195	30	318	793	719	379	71	12	2322
195 - 205	35	318	657	433	268	72	9	1792
205 - 215	46	305	546	326	271	69	16	1579
215 - 225	31	300	516	346	301	152	52	1698
225 - 235	53	298	554	380	382	238	138	2043
235 - 245	47	292	635	350	238	151	82	1795
245 - 255	36	299	611	311	120	48	29	1454
255 - 265	21	248	422	165	55	21	9	941
265 - 275	40	245	358	72	37	19	4	775
275 - 285	34	203	251	34	15	8	2	547
285 - 295	43	247	247	25	11	5	0	578
295 - 305	41	302	275	34	19	8	2	681
305 - 315	42	279	353	59	27	11	3	774
315 - 325	37	296	496	118	37	18	9	1011
325 - 335	30	331	783	274	120	31	11	1580
335 - 345	37	338	956	485	253	113	43	2225
345 - 355	38	344	918	497	357	188	119	2461
Sub-Total	1250	9777	16452	8325	4554	1686	719	42763
							Calms	864
							Missing/Incomplete*	197

Average Wind Speed: 3.64 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2009 ANNUAL
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	6	61	105	82	41	24	23	342
5 - 15	10	49	67	37	16	10	9	198
15 - 25	5	41	64	9	3	0	4	126
25 - 35	8	52	46	13	1	0	0	120
35 - 45	8	42	32	10	2	0	0	94
45 - 55	5	41	34	7	3	1	0	91
55 - 65	7	40	50	12	5	0	0	114
65 - 75	8	50	32	5	0	0	0	95
75 - 85	2	45	40	5	2	0	0	94
85 - 95	8	52	40	2	1	0	0	103
95 - 105	4	41	30	6	0	1	0	82
105 - 115	4	37	36	1	1	0	0	79
115 - 125	6	62	41	4	2	0	0	115
125 - 135	9	52	50	4	1	0	0	116
135 - 145	2	57	62	12	1	0	0	134
145 - 155	9	41	118	36	4	1	0	209
155 - 165	6	62	154	117	47	2	0	388
165 - 175	5	68	163	211	100	29	1	577
175 - 185	7	63	165	193	98	21	3	550
185 - 195	6	58	165	175	77	27	1	509
195 - 205	10	69	144	100	57	18	5	403
205 - 215	8	58	136	77	62	13	2	356
215 - 225	8	56	119	80	72	23	8	366
225 - 235	13	60	115	87	77	45	15	412
235 - 245	9	51	149	82	48	18	14	371
245 - 255	7	77	127	64	21	9	7	312
255 - 265	5	51	64	45	11	4	1	181
265 - 275	4	50	67	12	10	3	1	147
275 - 285	7	37	48	14	6	2	0	114
285 - 295	9	50	53	4	0	3	0	119
295 - 305	9	61	52	4	8	1	2	137
305 - 315	7	64	80	10	9	2	2	174
315 - 325	9	55	91	19	13	6	3	196
325 - 335	10	70	156	67	39	5	2	349
335 - 345	8	60	199	99	72	25	8	471
345 - 355	9	63	151	84	76	42	19	444
Sub-Total	257	1946	3245	1789	986	335	130	8688
							Calms	59
							Missing/Incomplete*	197

Average Wind Speed: 3.72 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2009: FIRST QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	1	18	25	24	14	15	9	106
5 - 15	5	7	18	7	4	3	5	49
15 - 25	2	15	18	5	1	0	4	45
25 - 35	3	18	11	0	0	0	0	32
35 - 45	5	10	7	0	0	0	0	22
45 - 55	2	14	7	0	0	0	0	23
55 - 65	6	16	13	4	0	0	0	39
65 - 75	2	13	12	0	0	0	0	27
75 - 85	2	11	18	1	1	0	0	33
85 - 95	7	15	13	0	0	0	0	35
95 - 105	0	17	7	0	0	0	0	24
105 - 115	1	11	8	0	0	0	0	20
115 - 125	0	16	8	0	0	0	0	24
125 - 135	4	20	7	0	0	0	0	31
135 - 145	0	20	11	1	0	0	0	32
145 - 155	4	11	15	1	0	0	0	31
155 - 165	3	18	11	5	0	0	0	37
165 - 175	2	21	20	23	8	1	0	75
175 - 185	3	18	15	16	10	0	0	62
185 - 195	2	16	25	18	5	1	0	67
195 - 205	4	24	25	11	6	1	0	71
205 - 215	4	29	28	6	5	3	0	75
215 - 225	4	17	24	13	9	8	3	78
225 - 235	6	27	33	18	10	15	6	115
235 - 245	5	18	55	15	6	1	4	104
245 - 255	2	27	34	9	2	1	2	77
255 - 265	1	18	16	10	1	2	0	48
265 - 275	2	17	18	4	2	2	0	45
275 - 285	4	14	12	3	0	0	0	33
285 - 295	4	16	11	1	0	0	0	32
295 - 305	2	21	12	1	0	1	0	37
305 - 315	1	18	32	2	1	0	0	54
315 - 325	3	20	36	7	8	1	2	77
325 - 335	1	22	59	27	16	1	2	128
335 - 345	4	17	59	51	46	9	1	187
345 - 355	4	20	51	40	34	20	10	179
Sub-Total	105	630	774	323	189	85	48	2154
							Calms	5
							Missing/Incomplete*	197

Average Wind Speed: 3.42 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2009: SECOND QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	0	11	16	10	3	0	0	40
5 - 15	2	14	13	10	5	0	0	44
15 - 25	2	6	12	0	0	0	0	20
25 - 35	2	9	11	4	0	0	0	26
35 - 45	0	13	5	5	1	0	0	24
45 - 55	1	6	8	1	0	0	0	16
55 - 65	0	4	6	3	0	0	0	13
65 - 75	0	13	7	2	0	0	0	22
75 - 85	0	7	6	0	0	0	0	13
85 - 95	0	5	5	0	0	0	0	10
95 - 105	1	7	6	2	0	0	0	16
105 - 115	1	6	7	0	0	0	0	14
115 - 125	0	11	11	1	0	0	0	23
125 - 135	0	9	15	1	0	0	0	25
135 - 145	1	11	11	3	0	0	0	26
145 - 155	0	8	43	8	1	0	0	60
155 - 165	0	11	52	41	21	1	0	126
165 - 175	0	11	59	88	48	19	1	226
175 - 185	1	12	53	75	38	7	1	187
185 - 195	0	12	50	66	33	12	0	173
195 - 205	1	12	53	45	29	11	2	153
205 - 215	0	2	45	29	25	5	2	108
215 - 225	1	11	35	29	35	10	4	125
225 - 235	0	6	32	25	37	16	7	123
235 - 245	1	4	28	35	19	9	4	100
245 - 255	1	9	20	22	8	2	1	63
255 - 265	0	9	14	19	6	1	1	50
265 - 275	0	7	14	2	8	1	1	33
275 - 285	0	8	12	7	6	2	0	35
285 - 295	0	9	8	3	0	3	0	23
295 - 305	2	8	9	1	6	0	2	28
305 - 315	2	13	9	2	3	1	1	31
315 - 325	1	4	16	3	2	1	0	27
325 - 335	1	10	15	13	8	1	0	48
335 - 345	1	11	37	4	4	0	0	57
345 - 355	0	10	27	12	4	0	0	53
Sub-Total	22	319	770	571	350	102	27	2161
							Calms	19
							Missing/Incomplete*	197

Average Wind Speed: 4.22 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2009: THIRD QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	3	9	22	10	6	2	2	54
5 - 15	1	7	11	3	0	0	0	22
15 - 25	0	6	10	0	0	0	0	16
25 - 35	0	4	10	2	1	0	0	17
35 - 45	0	9	6	3	1	0	0	19
45 - 55	1	3	10	5	3	1	0	23
55 - 65	0	6	15	5	5	0	0	31
65 - 75	2	9	7	3	0	0	0	21
75 - 85	0	10	10	4	1	0	0	25
85 - 95	0	13	11	2	1	0	0	27
95 - 105	1	7	10	4	0	1	0	23
105 - 115	0	9	15	1	1	0	0	26
115 - 125	2	11	15	3	2	0	0	33
125 - 135	1	7	23	2	1	0	0	34
135 - 145	0	14	28	7	1	0	0	50
145 - 155	0	8	49	26	3	1	0	87
155 - 165	0	15	67	63	26	1	0	172
165 - 175	0	13	62	84	41	6	0	206
175 - 185	1	14	76	84	42	11	2	230
185 - 195	1	10	69	78	29	12	1	200
195 - 205	1	10	42	34	15	5	2	109
205 - 215	0	13	44	30	26	3	0	116
215 - 225	0	9	38	29	14	1	0	91
225 - 235	1	5	31	33	22	8	0	100
235 - 245	1	7	32	24	18	5	2	89
245 - 255	1	11	34	27	7	4	1	85
255 - 265	2	6	15	9	4	1	0	37
265 - 275	1	6	16	5	0	0	0	28
275 - 285	1	4	6	1	0	0	0	12
285 - 295	1	5	14	0	0	0	0	20
295 - 305	0	7	12	0	0	0	0	19
305 - 315	0	9	13	0	1	0	0	23
315 - 325	1	13	7	0	0	0	0	21
325 - 335	2	12	18	0	1	0	0	33
335 - 345	0	7	29	6	4	3	0	49
345 - 355	0	7	13	5	6	2	3	36
Sub-Total	25	315	890	592	282	67	13	2184
							Calms	17
							Missing/Incomplete*	197

Average Wind Speed: 3.96 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2009: FOURTH QUARTER

WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	2	23	42	38	18	7	12	142
5 - 15	2	21	25	17	7	7	4	83
15 - 25	1	14	24	4	2	0	0	45
25 - 35	3	21	14	7	0	0	0	45
35 - 45	3	10	14	2	0	0	0	29
45 - 55	1	18	9	1	0	0	0	29
55 - 65	1	14	16	0	0	0	0	31
65 - 75	4	15	6	0	0	0	0	25
75 - 85	0	17	6	0	0	0	0	23
85 - 95	1	19	11	0	0	0	0	31
95 - 105	2	10	7	0	0	0	0	19
105 - 115	2	11	6	0	0	0	0	19
115 - 125	4	24	7	0	0	0	0	35
125 - 135	4	16	5	1	0	0	0	26
135 - 145	1	12	12	1	0	0	0	26
145 - 155	5	14	11	1	0	0	0	31
155 - 165	3	18	24	8	0	0	0	53
165 - 175	3	23	22	16	3	3	0	70
175 - 185	2	19	21	18	8	3	0	71
185 - 195	3	20	21	13	10	2	0	69
195 - 205	4	23	24	10	7	1	1	70
205 - 215	4	14	19	12	6	2	0	57
215 - 225	3	19	22	9	14	4	1	72
225 - 235	6	22	19	11	8	6	2	74
235 - 245	2	22	34	8	5	3	4	78
245 - 255	3	30	39	6	4	2	3	87
255 - 265	2	18	19	7	0	0	0	46
265 - 275	1	20	19	1	0	0	0	41
275 - 285	2	11	18	3	0	0	0	34
285 - 295	4	20	20	0	0	0	0	44
295 - 305	5	25	19	2	2	0	0	53
305 - 315	4	24	26	6	4	1	1	66
315 - 325	4	18	32	9	3	4	1	71
325 - 335	6	26	64	27	14	3	0	140
335 - 345	3	25	74	38	18	13	7	178
345 - 355	5	26	60	27	32	20	6	176
Sub-Total	105	682	811	303	165	81	42	2189
							Calms	18
							Missing/Incomplete*	197

Average Wind Speed: 3.30 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2010: ANNUAL
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	9	70	139	77	33	22	7	357
5 - 15	7	57	71	35	14	4	6	194
15 - 25	6	55	74	13	2	0	0	150
25 - 35	4	60	50	10	1	0	0	125
35 - 45	4	47	59	7	2	0	0	119
45 - 55	9	53	49	8	2	0	0	121
55 - 65	4	38	33	13	0	0	0	88
65 - 75	3	48	46	8	0	0	0	105
75 - 85	4	45	38	3	1	1	0	92
85 - 95	10	46	39	3	0	0	0	98
95 - 105	7	47	30	1	0	0	0	85
105 - 115	13	49	30	1	1	1	0	95
115 - 125	6	55	31	3	0	0	0	95
125 - 135	6	39	53	4	0	1	0	103
135 - 145	9	64	71	12	2	0	0	158
145 - 155	7	66	93	34	1	0	0	201
155 - 165	8	68	139	107	37	2	0	361
165 - 175	9	51	156	178	121	15	3	533
175 - 185	12	81	192	225	119	20	1	650
185 - 195	7	62	159	164	101	16	3	512
195 - 205	5	67	131	98	71	12	1	385
205 - 215	13	73	124	85	60	6	2	363
215 - 225	0	65	112	83	45	30	7	342
225 - 235	12	65	117	74	94	66	30	458
235 - 245	9	66	117	67	49	41	18	367
245 - 255	4	60	130	56	26	9	6	291
255 - 265	3	53	87	26	18	1	1	189
265 - 275	10	56	68	18	16	6	0	174
275 - 285	11	38	54	5	4	2	1	115
285 - 295	8	56	49	9	6	0	0	128
295 - 305	10	73	56	7	8	3	0	157
305 - 315	11	62	74	11	3	4	1	166
315 - 325	9	51	91	19	6	4	0	180
325 - 335	5	66	134	48	20	7	0	280
335 - 345	10	76	161	90	39	20	3	399
345 - 355	9	68	195	99	73	25	11	480
Sub-Total	273	2096	3252	1701	975	318	101	8716
							Calms	37
							Missing/Incomplete*	197

Average Wind Speed: 3.62 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2010: FIRST QUARTER

WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	4	27	41	30	16	12	5	135
5 - 15	2	24	21	11	4	1	6	69
15 - 25	1	18	30	2	1	0	0	52
25 - 35	2	19	27	4	0	0	0	52
35 - 45	1	16	22	5	1	0	0	45
45 - 55	3	16	20	4	2	0	0	45
55 - 65	0	13	10	5	0	0	0	28
65 - 75	2	13	21	3	0	0	0	39
75 - 85	1	22	12	0	1	0	0	36
85 - 95	1	13	9	0	0	0	0	23
95 - 105	3	18	10	0	0	0	0	31
105 - 115	4	13	12	0	0	0	0	29
115 - 125	4	20	6	1	0	0	0	31
125 - 135	5	16	5	1	0	0	0	27
135 - 145	5	14	9	0	1	0	0	29
145 - 155	3	15	11	2	0	0	0	31
155 - 165	2	19	20	6	1	1	0	49
165 - 175	2	19	30	10	8	1	2	72
175 - 185	5	23	20	17	3	2	0	70
185 - 195	3	11	20	13	8	4	1	60
195 - 205	0	19	20	11	12	4	0	66
205 - 215	5	19	13	13	5	1	2	58
215 - 225	0	13	22	17	7	7	3	69
225 - 235	2	18	27	18	14	9	3	91
235 - 245	3	17	30	14	4	4	1	73
245 - 255	3	24	30	12	7	0	3	79
255 - 265	1	19	24	1	3	0	1	49
265 - 275	3	18	20	5	3	1	0	50
275 - 285	5	13	16	1	1	0	1	37
285 - 295	2	22	13	2	2	0	0	41
295 - 305	2	27	16	1	2	0	0	48
305 - 315	5	21	26	2	0	0	0	54
315 - 325	5	18	32	8	3	0	0	66
325 - 335	2	22	38	13	6	3	0	84
335 - 345	2	27	51	42	15	8	3	148
345 - 355	5	27	62	38	32	8	6	178
Sub-Total	98	673	796	312	162	66	37	2144
							Calms	15
							Missing/Incomplete*	197

Average Wind Speed: 3.22 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2010: SECOND QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	1	13	24	8	8	3	0	57
5 - 15	1	13	12	6	7	0	0	39
15 - 25	0	10	13	0	0	0	0	23
25 - 35	0	7	7	1	1	0	0	16
35 - 45	1	8	11	1	1	0	0	22
45 - 55	1	9	9	0	0	0	0	19
55 - 65	0	9	5	0	0	0	0	14
65 - 75	0	10	6	0	0	0	0	16
75 - 85	1	5	9	0	0	0	0	15
85 - 95	1	7	10	0	0	0	0	18
95 - 105	1	6	5	0	0	0	0	12
105 - 115	1	14	2	0	0	0	0	17
115 - 125	0	8	8	0	0	0	0	16
125 - 135	0	4	16	0	0	0	0	20
135 - 145	1	13	23	2	0	0	0	39
145 - 155	1	7	24	7	0	0	0	39
155 - 165	1	14	38	28	15	0	0	96
165 - 175	1	11	45	58	31	4	0	150
175 - 185	1	21	60	67	30	4	0	183
185 - 195	0	15	44	42	23	0	0	124
195 - 205	1	12	34	28	25	6	0	106
205 - 215	0	9	46	23	26	4	0	108
215 - 225	0	17	32	28	19	14	3	113
225 - 235	2	15	35	32	49	41	24	198
235 - 245	0	12	30	20	35	26	12	135
245 - 255	0	7	31	28	13	8	3	90
255 - 265	0	9	22	16	6	1	0	54
265 - 275	1	14	18	8	11	1	0	53
275 - 285	1	9	13	2	1	1	0	27
285 - 295	1	8	9	5	3	0	0	26
295 - 305	0	17	8	5	3	0	0	33
305 - 315	1	12	15	5	3	1	0	37
315 - 325	1	11	16	6	1	1	0	36
325 - 335	0	13	29	15	7	3	0	67
335 - 345	3	19	30	17	13	1	0	83
345 - 355	0	15	27	11	15	3	0	71
Sub-Total	24	403	766	469	346	122	42	2172
							Calms	11
							Missing/Incomplete*	197

Average Wind Speed: 4.18 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2010: THIRD QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	1	17	21	0	0	0	0	39
5 - 15	3	7	8	1	0	0	0	19
15 - 25	2	12	12	1	0	0	0	27
25 - 35	0	16	6	1	0	0	0	23
35 - 45	1	13	10	0	0	0	0	24
45 - 55	0	13	7	4	0	0	0	24
55 - 65	3	8	6	5	0	0	0	22
65 - 75	0	14	9	4	0	0	0	27
75 - 85	0	9	11	1	0	1	0	22
85 - 95	1	13	13	1	0	0	0	28
95 - 105	1	12	9	0	0	0	0	22
105 - 115	2	8	10	1	1	1	0	23
115 - 125	0	10	11	2	0	0	0	23
125 - 135	1	8	19	2	0	1	0	31
135 - 145	0	15	28	6	1	0	0	50
145 - 155	1	24	41	25	1	0	0	92
155 - 165	1	19	54	61	18	1	0	154
165 - 175	1	10	55	81	71	10	1	229
175 - 185	2	13	65	113	70	9	0	272
185 - 195	0	12	68	78	57	8	1	224
195 - 205	1	14	50	42	24	1	1	133
205 - 215	2	18	47	31	18	1	0	117
215 - 225	0	11	32	27	13	4	0	87
225 - 235	3	12	29	19	23	5	0	91
235 - 245	1	10	26	24	8	7	0	76
245 - 255	1	11	31	10	5	0	0	58
255 - 265	1	6	15	6	0	0	0	28
265 - 275	3	5	12	3	1	1	0	25
275 - 285	4	3	8	1	0	0	0	16
285 - 295	2	6	7	1	0	0	0	16
295 - 305	5	6	10	0	0	0	0	21
305 - 315	2	10	17	0	0	0	0	29
315 - 325	0	6	13	1	0	0	0	20
325 - 335	0	10	19	1	0	0	0	30
335 - 345	1	13	24	1	0	0	0	39
345 - 355	1	11	23	1	0	0	0	36
Sub-Total	47	405	826	555	311	50	3	2197
							Calms	8
							Missing/Incomplete*	197

Average Wind Speed: 3.83 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2010: FOURTH QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	3	13	53	39	9	7	2	126
5 - 15	1	13	30	17	3	3	0	67
15 - 25	3	15	19	10	1	0	0	48
25 - 35	2	18	10	4	0	0	0	34
35 - 45	1	10	16	1	0	0	0	28
45 - 55	5	15	13	0	0	0	0	33
55 - 65	1	8	12	3	0	0	0	24
65 - 75	1	11	10	1	0	0	0	23
75 - 85	2	9	6	2	0	0	0	19
85 - 95	7	13	7	2	0	0	0	29
95 - 105	2	11	6	1	0	0	0	20
105 - 115	6	14	6	0	0	0	0	26
115 - 125	2	17	6	0	0	0	0	25
125 - 135	0	11	13	1	0	0	0	25
135 - 145	3	22	11	4	0	0	0	40
145 - 155	2	20	17	0	0	0	0	39
155 - 165	4	16	27	12	3	0	0	62
165 - 175	5	11	26	29	11	0	0	82
175 - 185	4	24	47	28	16	5	1	125
185 - 195	4	24	27	31	13	4	1	104
195 - 205	3	22	27	17	10	1	0	80
205 - 215	6	27	18	18	11	0	0	80
215 - 225	0	24	26	11	6	5	1	73
225 - 235	5	20	26	5	8	11	3	78
235 - 245	5	27	31	9	2	4	5	83
245 - 255	0	18	38	6	1	1	0	64
255 - 265	1	19	26	3	9	0	0	58
265 - 275	3	19	18	2	1	3	0	46
275 - 285	1	13	17	1	2	1	0	35
285 - 295	3	20	20	1	1	0	0	45
295 - 305	3	23	22	1	3	3	0	55
305 - 315	3	19	16	4	0	3	1	46
315 - 325	3	16	30	4	2	3	0	58
325 - 335	3	21	48	19	7	1	0	99
335 - 345	4	17	56	30	11	11	0	129
345 - 355	3	15	83	49	26	14	5	195
Sub-Total	104	615	864	365	156	80	19	2203
							Calms	3
							Missing/Incomplete*	197

Average Wind Speed: 3.26 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2011: ANNUAL
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	4	55	138	84	65	42	32	420
5 - 15	1	45	83	32	23	26	8	218
15 - 25	5	53	66	17	3	0	2	146
25 - 35	6	37	42	8	0	0	0	93
35 - 45	5	30	34	14	1	0	0	84
45 - 55	8	50	39	9	3	0	0	109
55 - 65	5	46	46	4	3	1	0	105
65 - 75	7	46	20	3	3	1	0	80
75 - 85	11	31	26	5	1	1	0	75
85 - 95	5	47	33	4	0	0	0	89
95 - 105	4	71	32	3	0	0	0	110
105 - 115	9	52	34	1	0	1	0	97
115 - 125	6	47	57	0	1	0	1	112
125 - 135	6	42	57	4	0	0	0	109
135 - 145	8	46	98	8	3	0	0	163
145 - 155	5	61	106	40	13	1	0	226
155 - 165	8	52	122	86	33	3	0	304
165 - 175	10	76	164	163	67	4	0	484
175 - 185	7	74	147	172	75	5	1	481
185 - 195	6	64	149	140	66	7	0	432
195 - 205	13	66	131	80	53	10	0	353
205 - 215	6	58	102	46	64	20	4	300
215 - 225	8	70	93	74	72	31	9	357
225 - 235	10	59	105	77	85	49	53	438
235 - 245	9	46	126	77	62	51	31	402
245 - 255	9	65	133	78	45	7	6	343
255 - 265	4	47	83	45	16	7	3	205
265 - 275	9	52	89	14	3	4	0	171
275 - 285	4	41	41	6	1	1	0	94
285 - 295	11	51	52	3	1	0	0	118
295 - 305	4	67	66	9	1	0	0	147
305 - 315	11	50	68	12	3	0	0	144
315 - 325	4	78	89	25	3	2	3	204
325 - 335	2	58	149	51	27	11	4	302
335 - 345	5	60	202	105	53	39	16	480
345 - 355	3	78	197	117	70	50	34	549
Sub-Total	238	1971	3219	1616	919	374	207	8544
							Calms	160
Average Wind Speed: 3.73 m/s							**Missing/Incomplete***	197

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2011: FIRST QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	1	23	45	42	35	28	19	193
5 - 15	0	8	29	10	16	13	4	80
15 - 25	2	20	22	5	1	0	2	52
25 - 35	4	15	13	4	0	0	0	36
35 - 45	3	9	6	3	0	0	0	21
45 - 55	1	18	12	2	2	0	0	35
55 - 65	3	16	12	0	0	0	0	31
65 - 75	0	13	5	0	0	0	0	18
75 - 85	4	8	7	0	0	0	0	19
85 - 95	1	18	5	1	0	0	0	25
95 - 105	3	26	8	0	0	0	0	37
105 - 115	3	25	7	0	0	0	0	35
115 - 125	1	16	10	0	0	0	0	27
125 - 135	2	12	8	0	0	0	0	22
135 - 145	3	15	24	0	0	0	0	42
145 - 155	2	23	18	5	0	0	0	48
155 - 165	0	9	18	10	0	0	0	37
165 - 175	3	28	24	11	2	0	0	68
175 - 185	4	26	14	17	7	2	0	70
185 - 195	2	19	22	13	6	3	0	65
195 - 205	5	16	18	10	6	1	0	56
205 - 215	1	16	17	6	10	3	1	54
215 - 225	4	16	13	13	11	8	0	65
225 - 235	3	15	20	12	19	12	6	87
235 - 245	2	9	37	14	15	12	2	91
245 - 255	3	25	31	10	13	3	0	85
255 - 265	0	12	15	1	9	0	0	37
265 - 275	4	13	27	1	0	0	0	45
275 - 285	1	16	14	1	0	0	0	32
285 - 295	1	16	17	0	0	0	0	34
295 - 305	2	20	32	2	0	0	0	56
305 - 315	5	13	22	3	2	0	0	45
315 - 325	2	33	27	7	1	0	0	70
325 - 335	2	18	39	14	8	3	1	85
335 - 345	2	15	57	41	20	12	1	148
345 - 355	2	29	57	57	31	17	9	202
Sub-Total	81	629	752	315	214	117	45	2153
							Calms	6
Average Wind Speed: 3.58 m/s							**Missing/Incomplete***	197

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2011: SECOND QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	0	11	26	12	7	5	2	63
5 - 15	0	11	20	8	2	7	3	51
15 - 25	1	8	15	7	0	0	0	31
25 - 35	1	3	6	3	0	0	0	13
35 - 45	0	8	7	7	0	0	0	22
45 - 55	0	10	12	1	1	0	0	24
55 - 65	0	6	11	1	0	0	0	18
65 - 75	1	5	3	1	0	0	0	10
75 - 85	1	5	5	0	0	0	0	11
85 - 95	0	10	7	2	0	0	0	19
95 - 105	1	7	8	2	0	0	0	18
105 - 115	2	2	9	0	0	0	0	13
115 - 125	1	5	8	0	0	0	0	14
125 - 135	1	6	12	2	0	0	0	21
135 - 145	2	6	15	3	2	0	0	28
145 - 155	0	9	24	5	7	1	0	46
155 - 165	2	4	41	23	7	2	0	79
165 - 175	1	9	38	49	27	2	0	126
175 - 185	0	15	39	45	16	1	0	116
185 - 195	2	7	40	41	24	1	0	115
195 - 205	2	11	43	29	22	5	0	112
205 - 215	0	13	39	15	28	12	2	109
215 - 225	2	13	28	30	41	19	7	140
225 - 235	0	14	35	34	47	34	46	210
235 - 245	2	8	22	19	34	29	24	138
245 - 255	0	10	28	37	17	4	5	101
255 - 265	0	8	20	16	6	6	2	58
265 - 275	1	15	18	6	0	2	0	42
275 - 285	0	3	5	1	0	0	0	9
285 - 295	2	9	6	2	0	0	0	19
295 - 305	0	8	11	4	1	0	0	24
305 - 315	1	10	19	3	0	0	0	33
315 - 325	0	10	28	8	0	0	0	46
325 - 335	0	13	33	14	10	6	1	77
335 - 345	0	13	35	21	8	6	3	86
345 - 355	0	12	39	14	11	9	12	97
Sub-Total	26	317	755	465	318	151	107	2139
							Calms	9
							Missing/Incomplete*	197

Average Wind Speed: 4.57 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2011: THIRD QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	2	4	16	4	2	0	0	28
5 - 15	1	10	11	2	0	0	0	24
15 - 25	1	8	11	1	0	0	0	21
25 - 35	1	2	3	0	0	0	0	6
35 - 45	0	5	3	2	0	0	0	10
45 - 55	2	7	7	2	0	0	0	18
55 - 65	2	7	9	1	3	1	0	23
65 - 75	1	15	2	1	3	1	0	23
75 - 85	3	8	8	5	1	1	0	26
85 - 95	2	5	10	1	0	0	0	18
95 - 105	0	11	11	1	0	0	0	23
105 - 115	0	8	5	1	0	1	0	15
115 - 125	0	8	27	0	1	0	1	37
125 - 135	0	8	28	2	0	0	0	38
135 - 145	2	9	42	5	1	0	0	59
145 - 155	1	10	50	29	6	0	0	96
155 - 165	0	17	50	51	26	1	0	145
165 - 175	1	14	85	92	34	1	0	227
175 - 185	0	13	75	90	44	2	1	225
185 - 195	1	18	68	79	33	2	0	201
195 - 205	1	24	57	35	20	3	0	140
205 - 215	0	6	37	22	20	1	0	86
215 - 225	0	15	35	27	10	1	0	88
225 - 235	2	9	28	25	13	1	0	78
235 - 245	0	11	28	37	6	3	0	85
245 - 255	1	6	37	25	11	0	1	81
255 - 265	1	4	24	20	1	1	0	51
265 - 275	1	5	19	4	1	1	0	31
275 - 285	1	7	8	3	0	1	0	20
285 - 295	2	4	11	0	1	0	0	18
295 - 305	1	11	9	0	0	0	0	21
305 - 315	0	9	11	3	1	0	0	24
315 - 325	2	15	8	3	0	0	0	28
325 - 335	0	8	22	2	1	0	0	33
335 - 345	1	9	25	6	1	1	2	45
345 - 355	0	15	25	8	8	4	3	63
Sub-Total	33	345	905	589	248	27	8	2155
							Calms	42
							Missing/Incomplete*	197

Average Wind Speed: 3.71 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2011: FOURTH QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	1	17	51	26	21	9	11	136
5 - 15	0	16	23	12	5	6	1	63
15 - 25	1	17	18	4	2	0	0	42
25 - 35	0	17	20	1	0	0	0	38
35 - 45	2	8	18	2	1	0	0	31
45 - 55	5	15	8	4	0	0	0	32
55 - 65	0	17	14	2	0	0	0	33
65 - 75	5	13	10	1	0	0	0	29
75 - 85	3	10	6	0	0	0	0	19
85 - 95	2	14	11	0	0	0	0	27
95 - 105	0	27	5	0	0	0	0	32
105 - 115	4	17	13	0	0	0	0	34
115 - 125	4	18	12	0	0	0	0	34
125 - 135	3	16	9	0	0	0	0	28
135 - 145	1	16	17	0	0	0	0	34
145 - 155	2	19	14	1	0	0	0	36
155 - 165	6	22	13	2	0	0	0	43
165 - 175	5	25	17	11	4	1	0	63
175 - 185	3	20	19	20	8	0	0	70
185 - 195	1	20	19	7	3	1	0	51
195 - 205	5	15	13	6	5	1	0	45
205 - 215	5	23	9	3	6	4	1	51
215 - 225	2	26	17	4	10	3	2	64
225 - 235	5	21	22	6	6	2	1	63
235 - 245	5	18	39	7	7	7	5	88
245 - 255	5	24	37	6	4	0	0	76
255 - 265	3	23	24	8	0	0	1	59
265 - 275	3	19	25	3	2	1	0	53
275 - 285	2	15	14	1	1	0	0	33
285 - 295	6	22	18	1	0	0	0	47
295 - 305	1	28	14	3	0	0	0	46
305 - 315	5	18	16	3	0	0	0	42
315 - 325	0	20	26	7	2	2	3	60
325 - 335	0	19	55	21	8	2	2	107
335 - 345	2	23	85	37	24	20	10	201
345 - 355	1	22	76	38	20	20	10	187
Sub-Total	98	680	807	247	139	79	47	2097
							Calms	103
							Missing/Incomplete*	197

Average Wind Speed: 3.08 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2012: ANNUAL
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	6	57	138	54	31	25	17	328
5 - 15	5	46	73	22	17	2	3	168
15 - 25	4	52	47	14	1	0	1	119
25 - 35	6	30	31	10	1	1	0	79
35 - 45	10	46	42	10	0	0	0	108
45 - 55	7	49	29	10	5	0	0	100
55 - 65	4	42	35	9	6	1	0	97
65 - 75	9	53	35	4	4	0	0	105
75 - 85	6	35	46	3	0	0	0	90
85 - 95	4	68	39	2	0	0	0	113
95 - 105	8	59	47	6	2	0	0	122
105 - 115	11	70	43	3	0	0	0	127
115 - 125	11	51	56	9	2	1	0	130
125 - 135	4	54	80	13	0	1	0	152
135 - 145	8	49	100	17	3	1	0	178
145 - 155	12	51	121	41	2	1	0	228
155 - 165	12	63	183	115	29	3	1	406
165 - 175	9	69	236	181	87	25	4	611
175 - 185	5	74	172	204	91	19	7	572
185 - 195	4	73	181	144	73	9	4	488
195 - 205	7	62	132	85	49	12	3	350
205 - 215	9	56	103	71	42	11	3	295
215 - 225	10	54	95	63	44	25	13	304
225 - 235	11	59	102	69	62	40	24	367
235 - 245	11	66	113	58	32	22	14	316
245 - 255	10	54	120	55	15	14	9	277
255 - 265	3	39	87	24	5	3	3	164
265 - 275	10	48	65	19	3	4	1	150
275 - 285	7	40	48	5	2	2	1	105
285 - 295	9	53	44	6	2	0	0	114
295 - 305	13	55	56	6	1	1	0	132
305 - 315	7	54	65	12	6	1	0	145
315 - 325	8	51	107	21	6	4	1	198
325 - 335	7	70	177	38	18	3	2	315
335 - 345	5	80	202	88	30	11	6	422
345 - 355	13	76	170	86	60	35	18	458
Sub-Total	285	2008	3420	1577	731	277	135	8433
							Calms	292
Average Wind Speed: 3.44 m/s							**Missing/Incomplete***	197

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2012: FIRST QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	1	9	51	28	23	14	15	141
5 - 15	0	9	21	9	12	1	3	55
15 - 25	2	10	21	10	1	0	1	45
25 - 35	1	4	10	4	0	0	0	19
35 - 45	2	14	11	2	0	0	0	29
45 - 55	1	17	11	2	0	0	0	31
55 - 65	1	16	11	1	0	0	0	29
65 - 75	4	19	9	1	0	0	0	33
75 - 85	2	10	16	0	0	0	0	28
85 - 95	1	24	12	0	0	0	0	37
95 - 105	2	9	9	2	0	0	0	22
105 - 115	3	18	9	0	0	0	0	30
115 - 125	6	15	9	1	0	0	0	31
125 - 135	1	16	8	0	0	0	0	25
135 - 145	4	10	7	1	0	0	0	22
145 - 155	2	8	14	0	0	0	0	24
155 - 165	4	14	21	13	1	0	1	54
165 - 175	2	18	36	23	9	4	1	93
175 - 185	3	22	21	28	15	2	0	91
185 - 195	1	26	35	14	8	0	0	84
195 - 205	1	16	24	11	11	5	1	69
205 - 215	3	20	20	12	16	6	0	77
215 - 225	4	15	22	6	2	14	10	73
225 - 235	5	16	24	12	7	19	16	99
235 - 245	3	19	26	8	4	7	9	76
245 - 255	2	13	19	7	2	5	1	49
255 - 265	1	16	26	4	1	1	0	49
265 - 275	2	11	13	7	1	0	0	34
275 - 285	2	18	20	1	0	1	1	43
285 - 295	4	16	11	0	0	0	0	31
295 - 305	3	17	15	2	0	1	0	38
305 - 315	1	12	21	5	3	1	0	43
315 - 325	1	13	39	14	4	1	1	73
325 - 335	2	16	53	19	9	1	2	102
335 - 345	2	20	64	37	18	9	2	152
345 - 355	2	16	56	34	32	17	11	168
Sub-Total	81	542	795	318	179	109	75	2099
							Calms	78
Average Wind Speed: 3.61 m/s							**Missing/Incomplete***	197

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2012: SECOND QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class 0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	1	15	22	11	6	7	1	63
5 - 15	2	12	11	3	2	0	0	30
15 - 25	2	10	11	3	0	0	0	26
25 - 35	2	7	8	3	0	0	0	20
35 - 45	4	9	11	0	0	0	0	24
45 - 55	0	6	4	1	2	0	0	13
55 - 65	0	2	12	2	2	0	0	18
65 - 75	1	5	7	1	0	0	0	14
75 - 85	2	2	10	2	0	0	0	16
85 - 95	0	7	5	0	0	0	0	12
95 - 105	1	6	11	0	0	0	0	18
105 - 115	1	8	8	1	0	0	0	18
115 - 125	1	7	16	1	0	0	0	25
125 - 135	0	7	20	3	0	0	0	30
135 - 145	1	7	27	4	0	0	0	39
145 - 155	1	10	33	14	1	1	0	60
155 - 165	2	14	53	23	14	2	0	108
165 - 175	2	12	67	62	33	16	2	194
175 - 185	0	11	44	65	39	9	5	173
185 - 195	1	8	47	42	35	8	4	145
195 - 205	1	14	34	25	27	7	2	110
205 - 215	1	8	29	32	20	4	3	97
215 - 225	0	3	27	32	30	8	0	100
225 - 235	2	7	28	24	40	20	3	124
235 - 245	0	9	20	25	20	12	5	91
245 - 255	1	7	37	22	5	6	6	84
255 - 265	0	3	19	9	1	1	3	36
265 - 275	1	6	18	7	1	3	1	37
275 - 285	0	4	10	2	1	0	0	17
285 - 295	1	7	15	4	2	0	0	29
295 - 305	2	7	14	2	0	0	0	25
305 - 315	1	6	12	4	2	0	0	25
315 - 325	1	7	26	3	2	3	0	42
325 - 335	1	10	36	7	2	1	0	57
335 - 345	0	15	39	12	4	1	4	75
345 - 355	1	12	27	19	14	8	3	84
Sub-Total	37	290	818	470	305	117	42	2079
							Calms	74
							Missing/Incomplete*	197

Average Wind Speed: 4.11 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2012: THIRD QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	0	10	18	1	0	0	0	29
5 - 15	1	8	11	3	0	0	0	23
15 - 25	0	12	2	1	0	0	0	15
25 - 35	0	10	5	3	1	1	0	20
35 - 45	0	9	10	8	0	0	0	27
45 - 55	0	8	9	7	3	0	0	27
55 - 65	2	5	7	6	4	1	0	25
65 - 75	2	5	14	2	4	0	0	27
75 - 85	1	7	12	1	0	0	0	21
85 - 95	1	10	12	2	0	0	0	25
95 - 105	0	12	21	4	2	0	0	39
105 - 115	0	18	20	2	0	0	0	40
115 - 125	1	12	20	7	2	1	0	43
125 - 135	0	6	34	10	0	1	0	51
135 - 145	1	12	49	11	3	1	0	77
145 - 155	0	11	49	26	1	0	0	87
155 - 165	0	20	81	69	11	1	0	182
165 - 175	1	21	99	78	44	5	1	249
175 - 185	0	22	87	87	33	8	2	239
185 - 195	0	18	81	72	22	1	0	194
195 - 205	1	12	50	36	6	0	0	105
205 - 215	1	9	34	19	1	0	0	64
215 - 225	3	10	27	16	0	0	1	57
225 - 235	1	6	25	23	4	0	0	59
235 - 245	1	7	35	22	4	1	0	70
245 - 255	1	8	29	21	3	2	1	65
255 - 265	0	5	17	9	2	1	0	34
265 - 275	1	12	10	4	1	1	0	29
275 - 285	1	7	7	1	0	1	0	17
285 - 295	2	4	6	1	0	0	0	13
295 - 305	3	10	4	0	1	0	0	18
305 - 315	0	13	7	0	0	0	0	20
315 - 325	0	13	11	0	0	0	0	24
325 - 335	2	6	18	1	0	0	0	27
335 - 345	0	14	27	4	0	0	0	45
345 - 355	1	17	23	4	0	0	1	46
Sub-Total	28	389	971	561	152	26	6	2133
							Calms	66
							Missing/Incomplete*	197

Average Wind Speed: 3.43 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2012: FOURTH QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	4	23	47	14	2	4	1	95
5 - 15	2	17	30	7	3	1	0	60
15 - 25	0	20	13	0	0	0	0	33
25 - 35	3	9	8	0	0	0	0	20
35 - 45	4	14	10	0	0	0	0	28
45 - 55	6	18	5	0	0	0	0	29
55 - 65	1	19	5	0	0	0	0	25
65 - 75	2	24	5	0	0	0	0	31
75 - 85	1	16	8	0	0	0	0	25
85 - 95	2	27	10	0	0	0	0	39
95 - 105	5	32	6	0	0	0	0	43
105 - 115	7	26	6	0	0	0	0	39
115 - 125	3	17	11	0	0	0	0	31
125 - 135	3	25	18	0	0	0	0	46
135 - 145	2	20	17	1	0	0	0	40
145 - 155	9	22	25	1	0	0	0	57
155 - 165	6	15	28	10	3	0	0	62
165 - 175	4	18	34	18	1	0	0	75
175 - 185	2	19	20	24	4	0	0	69
185 - 195	2	21	18	16	8	0	0	65
195 - 205	4	20	24	13	5	0	0	66
205 - 215	4	19	20	8	5	1	0	57
215 - 225	3	26	19	9	12	3	2	74
225 - 235	3	30	25	10	11	1	5	85
235 - 245	7	31	32	3	4	2	0	79
245 - 255	6	26	35	5	5	1	1	79
255 - 265	2	15	25	2	1	0	0	45
265 - 275	6	19	24	1	0	0	0	50
275 - 285	4	11	11	1	1	0	0	28
285 - 295	2	26	12	1	0	0	0	41
295 - 305	5	21	23	2	0	0	0	51
305 - 315	5	23	25	3	1	0	0	57
315 - 325	6	18	31	4	0	0	0	59
325 - 335	2	38	70	11	7	1	0	129
335 - 345	3	31	72	35	8	1	0	150
345 - 355	9	31	64	29	14	10	3	160
Sub-Total	139	787	836	228	95	25	12	2122
							Calms	74
							Missing/Incomplete*	197

Average Wind Speed: 2.61 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

SONORAN ENERGY PROJECT
BLYTHE, CA: 2009 THROUGH 2013
WIND FREQUENCY DISTRIBUTIONS

2013: ANNUAL
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	6	54	133	85	67	30	26	401
5 - 15	3	56	94	43	33	17	10	256
15 - 25	3	59	58	18	6	2	1	147
25 - 35	5	34	58	6	3	0	0	106
35 - 45	5	28	38	7	2	0	0	80
45 - 55	0	42	33	9	3	1	0	88
55 - 65	3	35	37	6	1	0	1	83
65 - 75	9	46	46	5	3	1	0	110
75 - 85	4	28	46	2	2	0	0	82
85 - 95	4	46	56	11	1	0	0	118
95 - 105	3	39	56	4	2	1	0	105
105 - 115	7	36	40	1	0	0	1	85
115 - 125	4	53	54	6	0	0	0	117
125 - 135	1	44	47	11	2	0	0	105
135 - 145	6	39	71	17	1	0	0	134
145 - 155	11	41	115	42	8	0	0	217
155 - 165	6	39	154	116	69	18	0	402
165 - 175	3	58	176	212	113	43	3	608
175 - 185	9	63	150	204	109	30	3	568
185 - 195	7	61	139	96	62	12	4	381
195 - 205	0	54	119	70	38	20	0	301
205 - 215	10	60	81	47	43	19	5	265
215 - 225	5	55	97	46	68	43	15	329
225 - 235	7	55	115	73	64	38	16	368
235 - 245	9	63	130	66	47	19	5	339
245 - 255	6	43	101	58	13	9	1	231
255 - 265	6	58	101	25	5	6	1	202
265 - 275	7	39	69	9	5	2	2	133
275 - 285	5	47	60	4	2	1	0	119
285 - 295	6	37	49	3	2	2	0	99
295 - 305	5	46	45	8	1	3	0	108
305 - 315	6	49	66	14	6	4	0	145
315 - 325	7	61	118	34	9	2	2	233
325 - 335	6	67	167	70	16	5	3	334
335 - 345	9	62	192	103	59	18	10	453
345 - 355	4	59	205	111	78	36	37	530
Sub-Total	197	1756	3316	1642	943	382	146	8382
							Calms	316
							Missing/Incomplete*	197

Average Wind Speed: 3.69 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2013: FIRST QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	4	19	50	29	29	11	10	152
5 - 15	0	16	35	16	9	6	2	84
15 - 25	1	21	24	11	1	0	0	58
25 - 35	1	5	24	2	1	0	0	33
35 - 45	1	11	15	1	0	0	0	28
45 - 55	0	18	13	2	0	0	0	33
55 - 65	2	10	14	1	0	0	0	27
65 - 75	4	21	16	0	0	0	0	41
75 - 85	2	9	14	0	0	0	0	25
85 - 95	2	9	15	0	0	0	0	26
95 - 105	0	11	16	0	0	0	0	27
105 - 115	4	13	9	0	0	0	0	26
115 - 125	2	22	11	0	0	0	0	35
125 - 135	0	12	8	0	0	0	0	20
135 - 145	1	11	12	0	0	0	0	24
145 - 155	1	16	24	3	1	0	0	45
155 - 165	3	13	22	10	0	0	0	48
165 - 175	1	13	19	11	0	0	0	44
175 - 185	5	17	16	23	1	0	0	62
185 - 195	4	20	28	9	2	1	0	64
195 - 205	0	18	18	7	5	0	0	48
205 - 215	3	21	9	7	5	1	0	46
215 - 225	1	20	20	7	18	11	2	79
225 - 235	1	17	28	15	13	6	5	85
235 - 245	4	26	32	16	10	6	3	97
245 - 255	3	20	24	8	2	3	0	60
255 - 265	2	18	23	8	3	0	0	54
265 - 275	3	17	15	3	2	0	0	40
275 - 285	2	25	18	1	0	1	0	47
285 - 295	4	13	15	1	0	0	0	33
295 - 305	1	19	15	2	1	0	0	38
305 - 315	3	14	21	5	1	0	0	44
315 - 325	3	15	40	10	0	0	0	68
325 - 335	3	23	40	30	2	1	2	101
335 - 345	3	9	70	41	26	3	7	159
345 - 355	3	24	59	48	36	13	5	188
Sub-Total	77	586	832	327	168	63	36	2089
							Calms	53
							Missing/Incomplete*	197

Average Wind Speed: 3.30 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2013: SECOND QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

	Hours by Wind Speed Class							
Directions	**0.5 - 1**	**1 - 2**	**2 - 4**	**4 - 6**	**6 - 8**	**8 - 10**	**>= 10**	**Total**
355 - 5	0	12	14	3	8	6	8	51
5 - 15	1	13	14	4	12	6	5	55
15 - 25	0	11	8	1	1	2	1	24
25 - 35	1	6	6	1	2	0	0	16
35 - 45	1	7	3	1	1	0	0	13
45 - 55	0	6	7	1	1	0	0	15
55 - 65	1	4	4	3	0	0	0	12
65 - 75	1	9	9	2	0	0	0	21
75 - 85	0	3	7	0	0	0	0	10
85 - 95	0	10	6	0	0	0	0	16
95 - 105	2	7	11	0	0	0	0	20
105 - 115	0	6	4	1	0	0	0	11
115 - 125	0	11	16	2	0	0	0	29
125 - 135	1	11	16	2	0	0	0	30
135 - 145	0	8	19	10	0	0	0	37
145 - 155	4	9	38	20	5	0	0	76
155 - 165	1	7	41	38	39	6	0	132
165 - 175	0	17	55	84	52	22	0	230
175 - 185	1	12	56	73	45	8	0	195
185 - 195	0	12	46	37	26	2	0	123
195 - 205	0	11	34	28	17	10	0	100
205 - 215	0	17	25	22	18	11	2	95
215 - 225	1	11	27	21	32	25	4	121
225 - 235	4	6	27	28	40	20	3	128
235 - 245	1	9	25	31	21	11	1	99
245 - 255	0	6	16	22	5	2	0	51
255 - 265	0	9	22	9	2	3	0	45
265 - 275	0	9	19	0	3	1	1	33
275 - 285	1	7	12	1	2	0	0	23
285 - 295	0	4	6	1	2	2	0	15
295 - 305	1	9	6	3	0	2	0	21
305 - 315	0	7	17	8	4	4	0	40
315 - 325	0	14	17	9	7	1	1	49
325 - 335	1	13	35	6	6	4	1	66
335 - 345	3	12	36	10	10	1	0	72
345 - 355	0	13	50	10	9	1	18	101
Sub-Total	26	338	754	492	370	150	45	2175
							Calms	5
							Missing/Incomplete*	197

Average Wind Speed: 4.39 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2013: THIRD QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	0	10	21	6	3	0	0	40
5 - 15	1	13	10	1	0	0	0	25
15 - 25	2	17	9	2	0	0	0	30
25 - 35	3	13	10	1	0	0	0	27
35 - 45	2	7	7	2	0	0	0	18
45 - 55	0	8	3	4	0	1	0	16
55 - 65	0	14	9	0	0	0	1	24
65 - 75	3	8	14	1	3	1	0	30
75 - 85	1	12	12	2	2	0	0	29
85 - 95	2	13	22	10	1	0	0	48
95 - 105	1	13	24	4	2	1	0	45
105 - 115	2	9	18	0	0	0	1	30
115 - 125	0	12	16	4	0	0	0	32
125 - 135	0	10	11	9	2	0	0	32
135 - 145	3	9	26	6	1	0	0	45
145 - 155	4	9	47	18	0	0	0	78
155 - 165	0	9	73	62	23	11	0	178
165 - 175	0	10	86	104	54	20	3	277
175 - 185	2	20	58	98	55	16	2	251
185 - 195	0	14	55	39	30	7	4	149
195 - 205	0	9	50	32	10	3	0	104
205 - 215	4	14	34	17	11	3	0	83
215 - 225	2	13	28	12	7	3	4	69
225 - 235	2	9	26	20	6	3	1	67
235 - 245	2	9	30	13	9	0	0	63
245 - 255	0	6	20	20	4	3	0	53
255 - 265	2	7	17	7	0	1	0	34
265 - 275	1	4	15	6	0	1	0	27
275 - 285	1	4	9	2	0	0	0	16
285 - 295	0	12	5	1	0	0	0	18
295 - 305	1	4	8	2	0	1	0	16
305 - 315	2	13	9	0	0	0	0	24
315 - 325	2	18	14	4	0	0	0	38
325 - 335	1	11	21	8	4	0	0	45
335 - 345	2	16	28	15	7	0	0	68
345 - 355	1	7	41	11	4	1	0	65
Sub-Total	49	386	886	543	238	76	16	2194
							Calms	13
							Missing/Incomplete*	197

Average Wind Speed: 3.80 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

2013: FOURTH QUARTER
WIND SPEEDS AT 10 FEET HEIGHT (m/s)

Directions	Hours by Wind Speed Class							
	0.5 - 1	1 - 2	2 - 4	4 - 6	6 - 8	8 - 10	>= 10	Total
355 - 5	2	13	48	47	27	13	8	158
5 - 15	1	14	35	22	12	5	3	92
15 - 25	0	10	17	4	4	0	0	35
25 - 35	0	10	18	2	0	0	0	30
35 - 45	1	3	13	3	1	0	0	21
45 - 55	0	10	10	2	2	0	0	24
55 - 65	0	7	10	2	1	0	0	20
65 - 75	1	8	7	2	0	0	0	18
75 - 85	1	4	13	0	0	0	0	18
85 - 95	0	14	13	1	0	0	0	28
95 - 105	0	8	5	0	0	0	0	13
105 - 115	1	8	9	0	0	0	0	18
115 - 125	2	8	11	0	0	0	0	21
125 - 135	0	11	12	0	0	0	0	23
135 - 145	2	11	14	1	0	0	0	28
145 - 155	2	7	6	1	2	0	0	18
155 - 165	2	10	18	6	7	1	0	44
165 - 175	2	18	16	13	7	1	0	57
175 - 185	1	14	20	10	8	6	1	60
185 - 195	3	15	10	11	4	2	0	45
195 - 205	0	16	17	3	6	7	0	49
205 - 215	3	8	13	1	9	4	3	41
215 - 225	1	11	22	6	11	4	5	60
225 - 235	0	23	34	10	5	9	7	88
235 - 245	2	19	43	6	7	2	1	80
245 - 255	3	11	41	8	2	1	1	67
255 - 265	2	24	39	1	0	2	1	69
265 - 275	3	9	20	0	0	0	1	33
275 - 285	1	11	21	0	0	0	0	33
285 - 295	2	8	23	0	0	0	0	33
295 - 305	2	14	16	1	0	0	0	33
305 - 315	1	15	19	1	1	0	0	37
315 - 325	2	14	47	11	2	1	1	78
325 - 335	1	20	71	26	4	0	0	122
335 - 345	1	25	58	37	16	14	3	154
345 - 355	0	15	55	42	29	21	14	176
Sub-Total	45	446	844	280	167	93	49	1924
							Calms	245
							Missing/Incomplete*	197

Average Wind Speed: 3.27 m/s

* Indicates that some or all of the data fields in the dataset are missing or incomplete for an hour.

Appendix 3.1B
Detailed Emission Calculations

APPENDIX 3.1B

Table 3.1B-1
Sonoran Energy Project
GE Performance Runs for 7HA.02 Gas Turbine

Case Description	Hot 100% Load DF w/Evap Cooling	Hot 100% Load no DF w/Evap Cooling	Hot Min Load no Evap Cooling	Avg 100% Load DF w/Evap Cooling	Avg 100% Load no DF w/Evap Cooling	Avg. Min Load no Evap Cooling	ISO 100% Load w/ DF, w/ Evap Cooling	ISO 100% Load w/ DF, no Evap Cooling	Cold 100% Load w/ DF	Cold 100% Load no DF	Cold Min Load
Case #	**9**	**10**	**11**	**6**	**7**	**8**	**1**	**2**	**3**	**4**	**5**
Ambient Conditions											
Dry Bulb, °F	110.0	110.0	110.0	74.0	74.0	74.0	59.0	59.0	39.0	39.0	39.0
Wet Bulb, °F											
RH, %	13.0	13.0	13.0	31.0	31.0	31.0	60.0	60.0	47.0	47.0	47.0
Altitude, ft	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0	350.0
Ambient Pressure, psia	14.511	14.511	14.511	14.511	14.511	14.511	14.511	14.511	14.511	14.511	14.511
Engine Inlet											
Comp Inlet Temp, °F	55.0	55.0	110.0	58.7	58.7	58.7	59.0	59.0	39.0	39.0	39.0
RH, %	75.2	75.2	13.0	85.0	85.0	31.0	60.0	92.9	47.0	47.0	47.0
Inlet chiller	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Evap Cooling	on	on	off	on	on	off	on	off	off	off	off
Partload %	**100**	**100**	**64**	**100**	**100**	**43**	**100**	**100**	**100**	**100**	**40**
Gross Power Output, kW	**526,546**	**497,325**	**289,030**	**525,291**	**496,258**	**248,868**	**531,397**	**523,256**	**543,923**	**515,193**	**245,648**
Plant Net Output, kW	**510,750**	**483,151**	**288,240**	**509,532**	**482,115**	**248,080**	**530,590**	**522,450**	**526,518**	**499,737**	**244,860**
Gross HR, Btu/kW-hr, HHV	**6,514**	**6,451**	**6,817**	**6,488**	**6,421**	**7,054**	**6,491**	**6,484**	**6,511**	**6,444**	**7,177**
Net HR, Btu/kW-hr, HHV	**6,715**	**6,640**	**6,836**	**6,688**	**6,609**	**7,076**	**6,501**	**6,494**	**6,726**	**6,643**	**7,200**
Fuel Flow											
MMBtu/hr, HHV	3,208	3,208	1,970	3,186	3,186	1,756	3,228	3,171	3,320	3,320	1,763
SCFM	51,854	51,854	31,846	51,502	51,502	28,374	52,173	51,260	53,659	53,659	28,493
lb/hr	140,295	140,295	86,164	139,346	139,346	76,771	141,161	138,690	145,185	145,180	77,094
NOx Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR
Duct Firing											
MMBtu/hr, LHV	199.4			199.44			199.44	199.44	199.44		
MMBtu/hr, HHV	221.6	0	0	221.6	0	0	221.6	221.6	221.6	0	0
lb/hr	9,691	0	0	9,691	0	0	9,691	9,691	9,691	0	0
SCFM	3,582	0	0	3,581.7	0.0	0.0	3,582	3,582	3,582	0	0
Total Heat Input, MMBtu/hr HHV	3,430	3,208.1	1,970.3	3,408	3,186	1,756	3,450	3,393	3,542	3,320	1,763
Exhaust Parameters											
Temperature, °F	163	176	165	158	168	153	157	157	155	163	150
lb/sec	1617	1614	1136	1580	1577	998	95813	94722	98405	98235	58937
lb/hr	5821700	5811500	4088800	5686400	5676200	3591900	5748800	5683300	5904300	5894100	3536200
%O2 (vol., dry)	12.14%	12.76%	13.93%	12.03%	12.67%	13.83%	12.03%	12.09%	12.09%	12.70%	13.70%
%CO2 (vol., dry)	5.03%	4.67%	4.01%	5.09%	4.72%	4.06%	5.09%	5.05%	5.06%	4.71%	4.14%
Estimated Maximum Emissions (at Stack)											
NOx ppmvd Ref 15% O2	2	2	2	2	2	2	2	2	2	2	2
NOx as NO2, lb/hr	25.2	23.4	14.4	25.0	23.3	12.8	25.3	24.9	26.0	24.2	12.9
CO ppmvd Ref 15% O2	2	2	2	2	2	2	2	2	2	2	2
CO, lb/hr	15.3	14.3	8.75	15.2	14.2	7.80	15.4	15.1	15.8	14.8	7.83
VOC, ppmvd Ref 15% O2	2	1	1	2	1	1	2	2	2	1	1
VOC, lb/hr		4.08	2.5	8.69	4.05	2.23	8.8	8.66	9.03	4.22	2.24
NH3 ppmvd Ref 15% O2	5	5	5	5	5	5	5	5	5	5	5

Table 3.1B-2
Sonoran Energy Project
Rapid Response Startup Emissions

Event	Duration, minutes	Emissions, lb/event				Emissions, lb/hr			
		NOx	CO	VOC	PM10/PM2.5	NOx	CO	VOC	PM10/PM2.5
Cold Start	45	181	132	10	6.6	188	136	12	9.1
Warm Start	40	146	130	10	5.9	155	135	13	9.2
Hot Start	21	97	123	9	3.1	114	133	15	9.6
Shutdown	14	4.9	136	28	2.1	25	148	35	9.8

Duration and lb/event from rev GE memo dated 2/24/15
lb/hr calculated assuming full load operation with duct firing for the rest of the hour.

Rapid Response Lite Startup Emissions

Event	Duration, minutes	Emissions, lb/event				Emissions, lb/hr			
		NOx	CO	VOC	PM10/PM2.5	NOx	CO	VOC	PM10/PM2.5
Cold Start	45	140	127	10	6.6	147	131	12	9.1
Warm Start	40	95	124	9	5.9	104	129	12	9.2
Hot Start	20	51	119	9	2.9	68	130	15	9.6
Shutdown	14	4.9	136	28	2.1	25	148	35	9.8

Duration and lb/event from rev GE memo dated 2/24/15
lb/hr calculated assuming full load operation with duct firing for the rest of the hour.

Table 3.1B-3
Sonoran Energy Project
Emissions and Operating Parameters for Auxiliary Boiler

Mfr/Model	Babcock & Wilcox FM 10-66 Package Boiler or equivalent		
Fuel	Natural Gas		
Load	100%	50%	25%
Steam Production, lb/hr	50,000	25,000	12,500
Steam Pressure, psi	300.00	300.00	300.00
Maximum Heat Input (MMBtu/hr)	66.3	32.3	16.2
F-factor (dscf/MMBtu)	8,710		
Reference O2	3.00%		
Actual O2	3.00%		
Exhaust Temperature (F)	600	480	441
Exhaust Rate (dscfm @ 3% O2)	10,958	5,335	2,683
Exhaust Rate (wacfm @ actual O2)	28,481	12,297	5,927

Pollutant	Emission Rate, ppmvd @ 3% O2	Emission Factors (lb/MMBtu)	Maximum Emissions (lb/hr)
NOx (normal operation)	7	0.0084	0.56
NOx (startup/shutdown)	25	0.0301	1.99
NOx (boiler tuning)	100	0.1202	7.97
SOx		0.0014	0.09
CO (normal operation)	50	0.0366	2.43
CO (startup/shutdown)	250	0.1830	12.13
VOC (normal operation)	7	0.0042	0.28
VOC (startup/shutdown)	25	0.0150	0.99
PM10	0.005 gr/dscf	0.007	0.46

Stack Diameter	35 inches	0.89 meters
Stack Height	50 feet	

Table 3.1B-4
Sonoran Energy Project
Emissions and Operating Parameters for Emergency Firepump Engine

Make/Model	Clarke JU6H-UFADR0 or equivalent
EPA Emissions Certification	Tier 3
Rating	238 bhp
Fuel	Diesel
Fuel Consumption	11.7 gal/hr
	1.61 MMBtu/hr(1)
Exhaust Temperature	848 deg F
Exhaust Diameter	6.065 inches
Exhaust Flow Rate	1513 acfm
Exhaust Velocity	125.7 ft/sec

	NOx	CO	VOC	SOx	PM10
Emission Factor (g/bhp-hr)	2.56	0.60	0.07	0.0047	0.08
Hourly Emissions (lb/hr)	1.34	0.31	0.04	0.0025	0.04

Notes:
(1) Based on default heat content for #2 diesel of 138,000 Btu/gal (from 40 CFR 98)

Table 3.1B-5
Sonoran Energy Project
Emissions and Operating Parameters for Cooling Tower

Manufacturer	SPX/Marley
Model	F448A48A3.010A
Number of towers	1
Number of cells per tower	10
Fan stack diameter (ft)	28
Exhaust temperature (F)	79.00
Exhaust flow rate per cell (acfm)	1,359,101
Water Circulation Rate, gal/min	129,480
Drift Rate	0.0005%
Water Drift (lbs/hr)	323.57
TDS Level, mg/L	5000
Emissions	
PM10 lb/hr	1.62
PM10 tpy	7.10
PM10 emissions per cell, lb/hr	0.162
PM10 emissions per cell, g/s	0.020

Table 3.1B-6
Sonoran Energy Project
Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

				NOx lb/hr		SOx lb/hr		CO lb/hr		VOC	PM10/PM2.5	NH3
Equipment	max. hour	hrs/day	hrs/yr	short-term (1)	annual avg (2)	short-term (1)	annual avg (2)	short-term (1)	annual avg (2)	lb/hr	lb/hr	lb/hr (3)
Gas Turbine 1, base load, no duct firing	0	0	5500	24.2	18.1	4.4	2.3	14.8	11.0	4.2	8.0	22.4
Gas Turbine 1, base load w/ duct firing	0	20	1500	26.0	19.4	4.9	2.5	15.8	11.8	9.0	10.0	23.9
Gas Turbine 1, cold starts	1	1	50	187.5	187.5	4.9	2.5	136.0	136.0	12.3	9.1	11.2
Gas Turbine 1, warm starts	0	0	150	154.7	154.7	4.9	2.5	135.3	135.3	13.0	9.2	11.2
Gas Turbine 1, hot starts	0	1	0	113.9	113.9	4.9	2.5	133.3	133.3	14.9	9.6	11.2
Gas Turbine 1, shutdowns	0	2	200	24.8	24.8	4.9	2.5	148.1	148.1	34.9	9.8	11.2
Auxiliary Boiler normal ops	1	22	6600	0.56	0.56	0.09	0.05	2.43	2.43	0.28	0.46	0.00
Auxiliary Boiler startup	0	2	400	1.99	1.99	0.09	0.05	12.13	12.13	0.69	0.46	0.00
Emergency Firepump Engine	0	24	200	1.34	1.34	0.00	0.00	0.31	0.31	0.04	0.04	0.00
Cooling Tower 1	1	24	8760	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.62	0.00

Notes:
1. Based on 2.0 ppm, 1-hour average
2. Based on 1.5 ppm, annual average
3. Based on 5.0 ppm, 3-hour average

Table 3.1B-6 (cont'd)
Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

	NOx			SOx			CO			VOC			PM10			NH3	
Equipment	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Total tpy
Gas Turbine 1, base load, no duct firing	0.0	0.0	49.90	0.0	0.0	6.3	0.0	0.0	30.4	0.0	0.0	11.6	0.0	0.0	22.0	0.0	61.6
Gas Turbine 1, base load w/ duct firing	0.0	520.0	14.52	0.0	98.1	1.8	0.0	316.0	8.8	0.0	180.6	6.8	10.0	200.0	7.5	0.0	17.9
Gas Turbine 1, cold starts	187.5	187.5	4.69	4.9	4.9	0.1	136.0	136.0	3.4	12.3	12.3	0.3	0.0	9.1	0.2	11.2	0.3
Gas Turbine 1, warm starts	0.0	0.0	11.60	0.0	0.0	0.2	0.0	0.0	10.1	0.0	0.0	1.0	0.0	0.0	0.7	0.0	0.8
Gas Turbine 1, hot starts	0.0	113.9	0.00	0.0	4.9	0.0	0.0	133.3	0.0	0.0	14.9	0.0	0.0	9.6	0.0	0.0	0.0
Gas Turbine 1, shutdowns	0.0	49.7	2.48	0.0	9.8	0.2	0.0	296.2	14.8	0.0	69.8	3.5	0.0	19.5	1.0	0.0	1.1
Auxiliary Boiler normal ops	0.6	12.3	1.84	0.09	2.01	0.15	2.4	53.4	8.00	0.28	6.1	0.92	0.46	10.20	1.5	0.00	0.00
Auxiliary Boiler startup	0.0	4.0	0.40	0.0	0.18	0.01	0.0	24.3	2.43	0.0	1.39	0.14	0.00	0.93	0.1	0.00	0.00
Emergency Firepump Engine	0.0	32.2	0.13	0.0	0.06	0.0002	0.0	7.6	0.03	0.0	0.9	0.00	0.00	1.01	4.20E-03	0.00	0.00
Cooling Tower	0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.62	38.90	7.1	0.00	0.00
Total, SEP	188.1	919.6	85.6	5.0	120.0	8.8	138.4	966.6	78.0	12.5	286.0	24.2	12.1	289.3	40.1	11.2	81.7
	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	tpy
Total, Current BEP II License		1,168.0	168.4		154.0	11.8		892.0	151.6		505.1	51.9		346.6	61.0		272.9

Table 3.1B-7
Sonoran Energy Project
Detailed Calculations for Maximum Hourly, Daily, and Annual Fuel Use

Equipment	Operating Schedule			Heat Input (1,2)			Power Generation	
	max. hour	hrs/day	hrs/yr	MMBtu/hr	MMBtu/day	MMBtu/yr	MW	GWh/yr
Gas Turbine 1, base load w/ duct firing	0	20	1500	3,557.9	71,158.3	5,336,876.1	543.9	815.9
Gas Turbine 1, base load, no duct firing	0	4	5500	3,335.3	13,341.2	18,344,090.8	515.2	2,833.6
Gas Turbine 1, cold starts	1	0	50	2,896.7	0.0	144,836.4	352.8	17.6
Gas Turbine 1, warm starts	0	0	150	2,918.4	0.0	437,752.5	338.5	50.8
Gas Turbine 1, hot starts	0	0	0	2,478.3	0.0	0.0	221.5	0.0
Gas Turbine 1, shutdowns	0	0	200	2,918.4	0.0	583,670.0	324.5	64.9
Auxiliary Boiler normal ops	1	24	6800	66.3	1,590.2	450,564.6	0	0.0
Auxiliary Boiler startup	0	0	200	66.3	0.0	13,251.9	0	0.0
Emergency Firepump Engine	0	24	200	1.6	38.8	322.9	0	0.0
Total, gas turbine					84,500	24,847,230	--	3,790.0
Total, aux boiler					1,600	463,820	--	0
SEP Total					86,128	25,311,365	--	3,790.0
Current BEP II license, gas turbines					114,765	37,900,412		
Current BEP II license, aux. boiler					1,440	150,007		
Current BEP II license, total					116,208	38,050,564		

Notes:
1. Reflects startup fuel consumption estimates for "Rapid Response" Startup Curves
2. Shutdown heat input assumes 12 min at max load w/o db and 48 min at same output as hot startup

Table 3.1B-8
Sonoran Energy Project
Gas Turbine Commissioning Schedule and Emissions

Altagas Sonoran 7HA.02 Rapid Response "Lite" Combined Cycle Power Plant Typical Commissioning Emissions, IPS 1006605, Rev 9, 2/9/15

TEST DESCRIPTION	GT LOAD	TOTAL FIRING	Estimated Emissions After Controls				Estimated Total Tons After Control				Estimated Max lb/day (from GE 2/9/15 memo)			
			NOx	CO	VOC	PM10	NOx		VOC	PM10	NOx		VOC	PM10
	%	hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	tons	CO tons	tons	tons	tons	CO tons	tons	tons
Power island pre-commissioning tests														
Auxiliary boiler firing, steam to gland seal, condenser vacuu	0	0.0												
HRSG chemical cleaning	0	0.0												
GT Initial Start-up														
GT first firing on primary fuel	0	5.0	295	228	17	8.0	**0.74**	**0.57**	**0.04**	**0.02**				
GT FSNL on primary fuel & generator filtration	0	7.5	295	228	17	8.0	**1.1**	**0.86**	**0.07**	**0.03**				
GT intertriping matrix checks	0	0.0	295	228	17	8.0	**0.0**	**0.00**	**0.00**	**0.00**				
GT generator short circuit, overspeed and open circuit tests	0	12.5	295	228	17	8.0	**1.8**	**1.4**	**0.11**	**0.05**				
GT Sync & Load														
GT first synchro	8	5.0	97	4919	464	8.0	**0.2**	**12.3**	**1.2**	**0.02**				
HRSG Steam blows														
HRSG MS steam blows	25	60.0	625	44	5.0	8.0	**18.7**	**1.3**	**0.15**	**0.24**				
HRSG CRH & HRH steam blows	25	43.75	625	44	5.0	8.0	**13.7**	**1.0**	**0.11**	**0.18**				
HRSG LP steam blows	25	15.0	625	44	5.0	8.0	**4.7**	**0.33**	**0.04**	**0.06**				
HRSG Operation on Steam Bypass														
HRSG startup, steam bypasses checks	50	60.0	187	28	2.5	8.0	**5.6**	**0.83**	**0.07**	**0.24**				
HRSG steam safety valves tests	50	60.0	187	28	2.5	8.0	**5.6**	**0.83**	**0.07**	**0.24**				
HRSG & BOP control loop tuning	50	40.0	187	28	2.5	8.0	**3.7**	**0.55**	**0.05**	**0.16**				
Load Catalyst														
GT Loading up to Base on PPM with Primary Fuel														
Part load tests	50	20.0	15	2.8	1.7	8.0	**0.15**	**0.03**	**0.02**	**0.08**				
Full load tests	100	7.5	25	4.1	2.6	8.0	**0.09**	**0.02**	**0.01**	**0.03**				
HRSG operation on bypass for steam purity	50	30.0	15	2.8	1.7	8.0	**0.22**	**0.04**	**0.03**	**0.12**				
ST Initial Start-up														
ST generator filtration	7	7.5	260	104	12	8.0	**1.0**	**0.39**	**0.05**	**0.03**				
ST intertriping checks	0	0.0	159	126	15	8.0	**0.0**	**0.0**	**0.0**	**0.00**				
ST generator short circuit, overspeed and open circuit tests	25	15.0	337	24	4.3	8.0	**2.5**	**0.18**	**0.03**	**0.06**				
ST Sync & Load														
ST first synchro	25	7.5	337	24	4.3	8.0	**1.3**	**0.1**	**0.02**	**0.03**				
ST tests on load with one GT	75	50.0	20	3.3	2.0	8.0	**0.49**	**0.08**	**0.05**	**0.20**				
GT Tuning up to Base with Primary Fuel														
Part load tests	50	52.5	15	2.8	1.7	8.0	**0.39**	**0.07**	**0.05**	**0.21**				
Full load tests	100	20.0	25	4.1	2.6	8.0	**0.25**	**0.04**	**0.03**	**0.08**				
CC Operation Tuning														
GT part load, full load rejection & house load tests	75	25.0	20	3.3	2.0	8.0	**0.24**	**0.04**	**0.03**	**0.10**				
GT, HRSG & ST trip tests and operation tuning	75	62.5	20	3.3	2.0	8.0	**0.61**	**0.10**	**0.06**	**0.25**				
ST full load	100	27.5	25	4.1	2.6	8.0	**0.34**	**0.06**	**0.04**	**0.11**				
Hot, warm, cold start-ups	50	60.0	15	2.8	1.7	8.0	**0.45**	**0.08**	**0.05**	**0.24**				
Restart	75	15.0	20	3.3	2.0	8.0	**0.15**	**0.02**	**0.02**	**0.06**				
Full Load	100	22.5	25	4.1	2.6	8.0	**0.28**	**0.05**	**0.03**	**0.09**				
GT's & ST part load, full load rejection & house load tests	100	22.5	25	4.1	2.6	8.0	**0.28**	**0.05**	**0.03**	**0.09**				
CC Performance tests (gaseous, noise emissions, output & HR)														
Capacity performance tests with primary fuel	100	45.0	25	4.1	2.6	8.0	**0.56**	**0.09**	**0.06**	**0.18**				
Precision performance tests with primary fuel	100	15.0	25	4.1	2.6	8.0	**0.19**	**0.03**	**0.02**	**0.06**				
Special tests														
Noise guarantee additional tests at part load	75	22.5	20	3.3	2.0	8.0	**0.22**	**0.04**	**0.02**	**0.09**				
Grid code tests, NPI tests, etc	75	0.0	20	3.3	2.0	8.0	**0.0**	**0.0**	**0.0**	**0.0**				
Other		0.0	159	126	15	8.0	**0.0**	**0.0**	**0.0**	**0.0**				
Reliability Run test														
9 days RR on primary fuel	100	384.0	25	4.1	2.6	8.0	**4.8**	**0.8**	**0.5**	**1.54**				
Commissioning Ends														
Total		1220.3	NA	NA	NA	NA	**70**	**22**	**3.0**	**4.9**				
Max Value			625	4919	464	8.0	**18.7**	**12.3**	**1.2**	**1.5**	**15,613**	**28,477**	**2,617**	**211**

Table 3.1B-9
Sonoran Energy Project
Greenhouse Gas Emissions Calculations

Unit	Total Number of Units	Heat Input (MMBtu/hr HHV)	Gross Output (kW)	Net Output (kW)	Operating Hours per year	Annual Fuel Use (MMBtu/yr HHV)	Estimated Annual Gross MWh	Estimated Annual Net MWh	Estimated Btu/kWh	Maximum Emissions, metric ton/yr				Facility-Wide Emissions, MT/yr CO2e	Facility-Wide Emissions, tons/yr CO2e	Facility-Wide CO2e MT/MWh		Gas Turbine CO2e lbs/MWh	
										CO2	CH4	N2O	SF6			Gross	Net	Gross	Net
Gas Turbine with duct firing	1	3,557.9	543,923	530,590	1500	5,336,876	815,884	795,885		283,175	5	0.5	--						
Gas Turbine Only	1	3,335.3	526,546	510,750	5500	18,344,091	2,896,003	2,809,123		973,337	18	1.8	--						
Gas Turbine startup/shutdown	1	varies	varies	varies	400	1,166,259	133,313	133,313		61,882	1	0.1	--						
Auxiliary Boiler	1	66.3	0	0	7000	463,816	n/a	n/a		24,610	0.5	0.05	--						
Fire Pump Engine	1	1.61	0	0	200	323	n/a	n/a		24	0.001	0.0002	--						
Circuit breakers	13	--	--	--	8760	0	n/a	n/a		--	--	--	0.0006						
Total						25,311,365	3,845,201	3,738,321	6,583	1,343,028	25	3	0.001						
CO2-Equivalent										1,343,028	633	754	13	1,344,428	1,481,963	0.350	0.360	771	793
Current Licensed Project										1,919,412	213	5		1,926,176					

Fuel	Emission Factors, kg/MMBtu			
	CO2 (1)	CH4 (2)	N2O (2)	SF6 (4)
Natural Gas	53.06	0.001	0.0001	n/a
Diesel Fuel	73.96	0.003	0.0006	n/a
Propane	62.87	0.003	0.0006	
Global Warming Potential (3)	1	25	298	22800

Notes: 1. 40 CFR 98, Table C-1 (revised 11/29/13).
2. 40 CFR 98, Table C-2 (revised 11/29/13).
3. 40 CFR 98, Table A-1 (revised 11/29/13).
4. Sulfur hexafluoride (SF6) will be used as an insulating medium in 2 circuit breakers. The SF6 contents of the circuit breakers is estimated as follows:
-- 1 245 kV breakers at 230 lb/breaker
-- 1 24 kV breaker at 25 lb/breaker
The IEC standard for SF6 leakage is less than 0.5%; the NEMA leakage standard for new circuit breakers is 0.1%. A maximum leakage rate of 0.5% per year is assumed.

Table 3.1B-10 Sonoran Energy Project Nitrogen Emissions

Annual NOx emissions, SEP	85.6	tpy
N/NO2 molecular weight ratio (14/46)	0.304	
N emissions from NO2	26.0	tpy
Annual NH3 emissions, SEP	81.7	tpy
N/NH3 molecular weight ratio (14/17)	0.824	
N emissions from NH3	67.3	tpy
Total Annual N from SEP	93.4	tpy
Annual Reductions in NOx from BEP	-105	tpy
N/NO2 molecular weight ratio (14/46)	0.304	
Reduction in N emissions from BEP	-32.0	tpy
NOx ERCs provided for SEP	-108.8	tpy
N/NO2 molecular weight ratio (14/46)	0.304	
N emissions from NO2	-33.1	tpy
Net N emissions change	28.3	tpy

Table 3.1B-11
Sonoran Energy Project
Emissions from Existing Blythe Energy Project

	Pollutant				
	NOx	SO2*	CO	VOC	PM10/PM2.5*
CT1 and CT2, with duct burner (each)					
pounds per hour	19.8	2.7	17.5	2.9	*6.2*
pounds per start	376	-	3600	-	--
pounds per day	2881	65	4002	119.5	*149.3*
CT1 and CT2, with duct burner (total)					
tons per year	97	*12*	97	24	*54.5*
Diesel fire water pump					
pounds per hour	9.39	0.62	2.02	0.75	6.70E-01
pounds per day	9.39	0.62	2.02	0.75	6.70E-01
tons per year	9.39E-02	6.20E-03	2.02E-02	7.50E-03	6.70E-03
Main cooling tower (each of 8 cells)					
pounds per hour	-	-	-	-	6.38E-02
pounds per day	-	-	-	-	1.53
tons per year	-	-	-	-	0.28
Chiller cooling tower (each of 12 cells)					
pounds per hour	-	-	-	-	3.00E-03
pounds per day	-	-	-	-	7.17E-02
tons per year	-	-	-	-	1.31E-02
Total, All Units					
pounds per hour	49.0	6.0	37.0	6.6	13.7
pounds per day	5,771.4	130.6	8,006.0	239.8	312.2
tons per year	97.1	12.0	97.0	24.0	56.9

Note:

* Gas turbine PM and SO2 emission rates reflect contemporaneous reductions proposed as part of this project.

Source:

BEP Title V permit (as amended May 7, 2015)

Table 3.1B-12
Sonoran Energy Project
Non-Criteria Pollutant Emissions Calculations

Gas Turbine

Pollutant	Uncontrolled Emission Factor, lb/MMBtu	Basis	Controlled Emission Factor, lb/MMBtu	Total Emissions, lb/hr (4)	Total Emissions, tpy (5)
Ammonia	6.71E-03	Permit Limit(3)	6.71E-03	23.9	81.7
Propylene	7.63E-04	0.5*CATEF(2)	3.82E-04	1.4	4.7
Hazardous Air Pollutants (HAPs) - Federal					
Acetaldehyde	4.00E-05	0.5*AP-42(1)	2.00E-05	7.12E-02	0.25
Acrolein	6.42E-06	0.5*AP-42(1)	3.21E-06	1.14E-02	0.04
Benzene	1.20E-05	0.5*AP-42(1)	5.99E-06	2.13E-02	0.07
1,3-Butadiene	4.30E-07	0.5*AP-42(1)	2.15E-07	7.65E-04	2.67E-03
Ethylbenzene	3.20E-05	0.5*AP-42(1)	1.60E-05	5.69E-02	0.20
Formaldehyde	9.00E-04	0.5*CATEF(2)	4.50E-04	1.60E+00	5.59
Hexane, n-	2.54E-04	0.5*CATEF(2)	1.27E-04	4.52E-01	1.58
Naphthalene	1.31E-06	0.5*AP-42(1)	6.53E-07	2.32E-03	0.01
Total PAHs (listed individually below)	6.43E-07	SUM	3.22E-07	1.14E-03	4.00E-03
Acenaphthene	1.86E-08	0.5*CATEF(2)	9.32E-09	3.32E-05	1.16E-04
Acenapthyene	1.44E-08	0.5*CATEF(2)	7.21E-09	2.57E-05	8.96E-05
Anthracene	3.32E-08	0.5*CATEF(2)	1.66E-08	5.91E-05	2.06E-04
Benzo(a)anthracene	2.22E-08	0.5*CATEF(2)	1.11E-08	3.95E-05	1.38E-04
Benzo(a)pyrene	1.36E-08	0.5*CATEF(2)	6.82E-09	2.43E-05	8.47E-05
Benzo(e)pyrene	5.34E-10	0.5*CATEF(2)	2.67E-10	9.50E-07	3.32E-06
Benzo(b)fluoranthrene	1.11E-08	0.5*CATEF(2)	5.54E-09	1.97E-05	6.88E-05
Benzo(k)fluoranthrene	1.08E-08	0.5*CATEF(2)	5.40E-09	1.92E-05	6.71E-05
Benzo(g,h,i)perylene	1.34E-08	0.5*CATEF(2)	6.72E-09	2.39E-05	8.35E-05
Chrysene	2.48E-08	0.5*CATEF(2)	1.24E-08	4.41E-05	1.54E-04
Dibenz(a,h)anthracene	2.30E-08	0.5*CATEF(2)	1.15E-08	4.09E-05	1.43E-04
Fluoranthene	4.24E-08	0.5*CATEF(2)	2.12E-08	7.54E-05	2.63E-04
Fluorene	5.70E-08	0.5*CATEF(2)	2.85E-08	1.01E-04	3.54E-04
Indeno(1,2,3-cd)pyrene	2.30E-08	0.5*CATEF(2)	1.15E-08	4.09E-05	1.43E-04
Phenanthrene	3.08E-07	0.5*CATEF(2)	1.54E-07	5.48E-04	1.91E-03
Pyrene	2.72E-08	0.5*CATEF(2)	1.36E-08	4.84E-05	1.69E-04
Propylene oxide	2.90E-05	0.5*AP-42(1)	1.45E-05	5.16E-02	0.18
Toluene	1.31E-04	0.5*AP-42(1)	6.53E-05	2.32E-01	0.81
Xylene	6.40E-05	0.5*AP-42(1)	3.20E-05	1.14E-01	0.40
Total HAPs					**9.14**

Notes:
(1) AP-42, Table 3.1-3, 4/00.
(2) From CARB CATEF database (converted from lbs/MMscf to lbs/MMBtu based on site natural gas HHV of 1,036 Btu/s
(3) Based on 5 ppm ammonia slip from SCR system.
(4) Based on maximum hourly heat input of 3,557.9 MMBtu/hr
(5) Based on proposed annual fuel use of 24,847,226 MMBtu/yr

Table 3.1B-12 (cont'd)
Auxiliary Boiler

Pollutant	Emission Factor, lb/MMscf	Basis	Emission Factor, lb/MMBtu (3)	Total Emissions, lb/hr (4)	Total Emissions, tpy (5)
Propylene	0.53	VCAPCD (1)	5.12E-04	0.03	0.12
Hazardous Air Pollutants (HAPs) - Federal					
Acetaldehyde	8.87E-03	CATEF (2)	8.56E-06	5.67E-04	1.99E-03
Acrolein	0.0027	VCAPCD (1)	2.61E-06	1.73E-04	6.04E-04
Benzene	4.31E-03	CATEF (2)	4.16E-06	2.76E-04	9.65E-04
Ethylbenzene	0.0069	VCAPCD (1)	6.66E-06	4.41E-04	1.54E-03
Formaldehyde	2.21E-01	CATEF (2)	2.13E-04	1.41E-02	4.95E-02
Hexane	0.0046	VCAPCD (1)	4.44E-06	2.94E-04	1.03E-03
Naphthalene	0.0003	VCAPCD (1)	2.90E-07	1.92E-05	6.72E-05
PAHs	0.0001	VCAPCD (1)	9.65E-08	6.40E-06	2.24E-05
Toluene	0.0265	VCAPCD (1)	2.56E-05	1.69E-03	5.93E-03
Xylene	0.0197	VCAPCD (1)	1.90E-05	1.26E-03	4.41E-03
Total HAPs					**6.60E-02**

Notes:
(1) Ventura County APCD, AB2588 Combustion Emission Factors, May 17, 2001.
(2) From CARB CATEF database.
(3) Converted from lbs/MMscf to lbs/MMBtu based on site natural gas HHV of 1,036 Btu/scf
(4) Based on maximum hourly heat input of 66.3 MMBtu/hr
(5) Based on proposed annual fuel use of 463,816 MMBtu/yr

Chemical	Units	Max. Conc. in Circ. Water (1)	Total Emissions, lb/hr	Total Emissions, tpy
Ammonia	ppm as NH3	NA	NA	NA
Arsenic	ppm as As	0.015	5.83E-07	2.55E-06
Cadmium	ppm as Cd	NA	NA	NA
Hexavalent Chromium	ppm as Cr	NA	NA	NA
Total Chromium	ppm as Cr	0	0.0	0.0
Copper	ppm as Cu	0.35	1.36E-05	5.95E-05
Lead	ppm as Pb	NA	NA	NA
Mercury	ppm as Hg	NA	NA	NA
Nickel	ppm as Ni	NA	NA	NA
Selenium	ppm as Se	0.045	1.75E-06	7.66E-06

Notes:
(1) From Section 2, Table 2.4. Assumes 5 cycles of concentration.
(2) Based on cooling tower water throughput of 7,768,800 gal/hr
68,055 MMgal/yr
and drift rate of 0.0005%

Diesel Fire Pump Engine

	Emission Rate, g/bhp-hr	Total Emissions, lb/hr	Total Emissions, tpy
Diesel Particulate Matter	0.08	0.04	4.20E-03

Table 3.1B-13
Sonoran Energy Project
Non-Criteria Pollutant Emissions Calculations for the BEP Gas Turbines

Pollutant	Uncontrolled Emission Factor, lb/MMBtu	Basis	Controlled Emission Factor, lb/MMBtu	Total Emissions, tpy (5)
Ammonia	1.34E-02	Permit Limit (3)	1.34E-02	213.9
Propylene	7.63E-04	0.5*CATEF(2)	3.82E-04	6.1
Hazardous Air Pollutants (HAPs) - Federal				
Acetaldehyde	4.00E-05	0.5*AP-42(1)	2.00E-05	0.32
Acrolein	6.42E-06	0.5*AP-42(1)	3.21E-06	0.05
Benzene	1.20E-05	0.5*AP-42(1)	5.99E-06	0.10
1,3-Butadiene	4.30E-07	0.5*AP-42(1)	2.15E-07	3.42E-03
Ethylbenzene	3.20E-05	0.5*AP-42(1)	1.60E-05	0.25
Formaldehyde	9.00E-04	0.5*CATEF(2)	4.50E-04	7.17
Hexane, n-	2.54E-04	0.5*CATEF(2)	1.27E-04	2.02
Naphthalene	1.31E-06	0.5*AP-42(1)	6.53E-07	0.01
Total PAHs (listed individually below)	6.43E-07	SUM	3.22E-07	5.12E-03
Acenaphthene	1.86E-08	0.5*CATEF(2)	9.32E-09	1.48E-04
Acenapthylene	1.44E-08	0.5*CATEF(2)	7.21E-09	1.15E-04
Anthracene	3.32E-08	0.5*CATEF(2)	1.66E-08	2.64E-04
Benzo(a)anthracene	2.22E-08	0.5*CATEF(2)	1.11E-08	1.77E-04
Benzo(a)pyrene	1.36E-08	0.5*CATEF(2)	6.82E-09	1.09E-04
Benzo(e)pyrene	5.34E-10	0.5*CATEF(2)	2.67E-10	4.25E-06
Benzo(b)fluoranthrene	1.11E-08	0.5*CATEF(2)	5.54E-09	8.82E-05
Benzo(k)fluoranthrene	1.08E-08	0.5*CATEF(2)	5.40E-09	8.60E-05
Benzo(g,h,i)perylene	1.34E-08	0.5*CATEF(2)	6.72E-09	1.07E-04
Chrysene	2.48E-08	0.5*CATEF(2)	1.24E-08	1.97E-04
Dibenz(a,h)anthracene	2.30E-08	0.5*CATEF(2)	1.15E-08	1.83E-04
Fluoranthene	4.24E-08	0.5*CATEF(2)	2.12E-08	3.38E-04
Fluorene	5.70E-08	0.5*CATEF(2)	2.85E-08	4.54E-04
Indeno(1,2,3-cd)pyrene	2.30E-08	0.5*CATEF(2)	1.15E-08	1.83E-04
Phenanthrene	3.08E-07	0.5*CATEF(2)	1.54E-07	2.45E-03
Pyrene	2.72E-08	0.5*CATEF(2)	1.36E-08	2.17E-04
Propylene oxide	2.90E-05	0.5*AP-42(1)	1.45E-05	0.23
Toluene	1.31E-04	0.5*AP-42(1)	6.53E-05	1.04
Xylene	6.40E-05	0.5*AP-42(1)	3.20E-05	0.51
Total HAPs				**11.71**

Notes:
(1) AP-42, Table 3.1-3, 4/00.
(2) From CARB CATEF database (converted from lbs/MMscf to lbs/MMBtu based on site natural gas HHV of 1,036 Btu/scf).
(3) Based on 10 ppm ammonia slip from SCR system.
(5) Based on maximum annual fuel use of 31,852,800 MMBtu/yr (permit limit)

Appendix 3.1C
Construction Impacts

APPENDIX 3.1C

Construction Impacts

3.1C.1 Construction Emissions

Construction of the proposed project is expected to last approximately 22 months. Construction activities will occur in the following main phases:

- Site preparation;
- Foundation work;
- Installation of major equipment; and
- Construction/installation of major structures.

The transmission route for the electricity generated by the project would use existing transmission infrastructure to the extent possible and would entail a short, approximately 1,320-foot transmission connection. Construction emissions related to the transmission line have been evaluated separately.

The emissions and resulting ambient air quality impacts were calculated for each phase and for both project and transmission line construction. The results of this analysis are discussed below.

Construction Activities and Emissions Calculations

Construction of the project will begin with site preparation activities, which include installation of drainage systems, underground utilities and conduits, grading and backfilling operations, and installation of pilings. After site preparation is finished, construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence. During grading and backfilling, engineered fill will be brought onsite to fill low areas where heavy equipment will be placed and excess soil removed during grading will be moved to adjacent property owned by the Project Owner. The excess soil will be stored in piles at this adjacent property until needed.

The primary emission sources during construction will include exhaust from heavy construction equipment and vehicles, and fugitive dust generated by grading and excavating activities.

Combustion emissions during construction will result from the following:

- Exhaust from diesel construction equipment used for site preparation, grading, excavation, trenching, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from portable welding machines;
- Exhaust from pickup trucks and diesel trucks used to transport workers and materials around the construction site;
- Exhaust from diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site including the heavy hauling of major components using truck and/or rail; and
- Exhaust from vehicles used by workers to commute to the construction site.

Fugitive dust emissions from the construction will result from the following:

- Dust entrained during site preparation and grading/excavation at the construction site;

- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Maximum short-term exhaust emissions impacts are calculated based on the equipment mix expected during Month 5 of the construction schedule, while maximum fugitive dust emissions are expected to occur during Month 13.[1] Annual emissions are based on the average equipment mix during the peak 12-month period out of the overall 22-month construction period. The detailed construction emissions calculations are shown in the tables attached to this analysis. As discussed in the modeling protocol submitted to the MDAQMD and CEC (see Appendix 3.1E), the CalEEMod model was used to calculate construction emissions for the proposed project. CalEEMod calculations were supplemented with manual calculations for windblown dust and some fugitive dust emissions, since those types of emissions are not handled well by the model. The following section provides additional details regarding the assumptions used in calculating emissions using CalEEMod, as well as the procedures used to calculate dust emissions external to the model.

Emissions of Fugitive Dust from Onsite Construction Activities. CalEEMod generates estimates for fugitive dust emissions only during the "grading" phase of the construction period. To ensure that fugitive dust emissions from onsite construction activities were not underestimated, the CalEEMod model phase type "Grading" was selected for the entire construction period. With this phase type selection, the CalEEMod model calculates dust emissions associated with various activities including grading, dozer operation, crawler tractor operation, and loader/loading activities.[2]

Emissions of Fugitive Dust from Soil Movement. Emissions from the import of fill material to SEP and the movement of excess soil from SEP to adjacent property owned by the Project Owner during Months 4-6 of the construction period were calculated manually. Dust emission from the soil movement activities result from several major activities:

- <u>Loading of fill material onto storage piles.</u> Emissions from adding material onto a receiving surface were calculated using EPA AP-42 methods. The amount of excess soil movement for these calculations was determined by estimating the amount of excess soil moved during each month. The material loaded onto the piles will be treated to control fugitive emissions.
- <u>Haul truck traffic to the storage area.</u> For the hauling of excess soil to the adjacent property, the haul trucks were assumed to travel on the access road between the two plants (BEP and SEP) and then via Riverside Avenue onto the dirt road that is west of Buck Blvd to the storage pile area (roughly halfway between the north and south boundary fences of the adjacent property). EPA AP-42 methods are used to calculate fugitive dust emissions for these unpaved haul truck travel.
- <u>Windblown dust.</u> Emissions of windblown dust from the soil storage pile at the adjacent property were estimated using the methods described in the SCAQMD CEQA air quality handbook.[3] The storage pile area was estimated by assuming a pile height of 15 feet and a rectangular surface area; the silt content approximated as 4.3% (consistent with the

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[1] See calculations in Attachment 3.1C-1.

[2] Section 4.3 of the CalEEMod User Guide, Appendix A.

[3] CEQA Air Quality Handbook, South Coast Air Quality Management District, Table A9-9-E

silt content of the soil). Dust suppression methods will be used to minimize windblown dust emissions from the soil storage pile until vegetation is established to hold the soil in place.

Detailed assumptions and calculations are documented in Attachment 3.1C-1.

Windblown Dust at the SEP Construction Site. Emissions of windblown dust are not accounted for in CalEEMod and must be calculated manually. The disturbed area for these calculations was determined by dividing the total active construction area (25 acres) by the months of construction. A PM_{10} emission factor of 0.011 ton/acre-month was used to estimate these emissions.[4]

Construction Access. As described in Section 2 of the Petition to Amend, primary construction access will be via a temporary construction access road off Hobson Way, at the southeast corner of the plant site. Additional construction access will be via the permanent plant access road to Hobson Way, at the southwest corner of the plant site. These primary construction access roads will be paved. Other portions of the SEP site will be graveled to provide internal access to project facilities and site buildings. The construction worker parking and laydown areas will be also be graveled to reduce the generation of fugitive dust. For the construction air quality impact analysis, onsite worker and delivery truck travel was assumed to occur on graveled surfaces (workers traveling to and from parking areas, delivery trucks traveling to and from laydown areas).

Onsite Vehicle Emissions. For delivery and haul vehicles, the onsite travel distance was taken as the distance from the plant entrance to the center of the laydown area. For worker vehicles, the onsite travel distance was taken as the distance from the plant entrance to the center of the parking area.

CalEEMod does not calculate exhaust emissions from delivery and worker vehicles traveling within the construction site, so these exhaust emissions were evaluated manually using the ratio of the onsite vehicle trip distance (one-way trip distances of 0.27 mile for worker travel and 0.46 mile for delivery and haul truck travel) to the offsite vehicle trip distances (one-way trip distances of 41 miles for workers and 60 miles for delivery and haul trucks).

For onsite vehicle fugitive dust emissions, EPA AP-42 methods were used to calculate dust emissions. As discussed above, onsite vehicle travel (workers, delivery and haul trucks) was assumed to occur on graveled surfaces.

Paved/Unpaved Surface Travel Emissions Calculation Assumptions. The CalEEMod model default silt content and silt loading values were used for the unpaved/paved surface travel emission calculations. As described in the CalEEMod model user guide (Section 4.4.3), EPA AP-42 methods are used to calculate fugitive dust emissions for paved and unpaved road travel. The CalEEMod model defaults for silt content/silt loading are based on statewide averages; these values are a silt content of 4.3% and a silt loading of 0.1 g/m2.

Exhaust Emission Source Assumptions. The number, type, and engine rating of the equipment used in the construction impact analysis were based on equipment schedules provided by the owner's engineer. The CalEEMod model default engine load factors were used for the construction emission calculations (a function of the type of construction equipment in question). Due to the large number of construction vehicles required for the project (which

[4] Source: Table ES-2, "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996.

impacts the availability of Tier 4 engines), it was assumed that EPA Tier 4i engines would be used for the larger equipment (engines equal to greater than 75 hp) and EPA Tier 4 engines would be used for smaller equipment (engines <75 hp).

Available Mitigation Measures

Listed below are typical mitigation measures that will be used to control exhaust emissions from the diesel equipment and potential emissions of fugitive dust during construction activities.

- Dust suppressants will be applied to unpaved surface travel and disturbed areas in the project construction site as frequently as necessary to prevent fugitive dust plumes. The frequency of application can be reduced or eliminated during periods of precipitation.
- The vehicle speed limit will be 10 miles per hour within the construction site.
- The construction site entrances will be posted with visible speed limit signs.
- Construction equipment vehicle tires will be inspected and cleaned as necessary to be cleaned free of dirt prior to entering paved roadways.
- Gravel ramps of at least 20 feet in length will be provided at the tire cleaning station.
- Unpaved exits from the construction site will be graveled or treated to prevent track-out to public roadways.
- Construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the Compliance Project Manager.
- Construction areas adjacent to any paved roadway will be provided with sandbags or other measures as specified in the Storm Water Pollution Prevention Plan (SWPPP) to prevent run-off to roadways.
- Paved roads within the construction site will be cleaned at least once per day (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.
- At least the first 500 feet of any public roadway exiting from the construction site will be cleaned at least once daily when dirt or runoff from the construction site is visible on public roadways.
- Soil storage piles and disturbed areas that remain inactive for longer than 10 days will be covered or treated with appropriate dust suppressant compounds.
- Vehicles used to transport solid bulk material on public roadways and having the potential to cause visible emissions will be provided with a cover, or the materials will be sufficiently wetted and loaded onto the trucks in a manner to provide at least one foot of freeboard.
- Wind erosion control techniques (such as windbreaks, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

An on-site Air Quality Construction Mitigation Manager will be responsible for directing and documenting compliance with construction-related mitigation conditions.

Estimates of Emissions with Mitigation Measures: Onsite Construction

Tables 3.1C-1 and 3.1C-2 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with the assumptions described above and the recommended mitigation measures for onsite construction activities. Detailed emission calculations are included as Attachment 3.1C-1.

TABLE 3.1C-1
Maximum Daily Emissions During Construction, Pounds per Day

	NOx	SO2	VOC	CO	PM10	PM2.5
Onsite						
Construction and Onsite Vehicle Exhaust	59.2	0.18	2.8	89.5	0.28	0.28
Fugitive Dust	--	--	--	--	19.0	3.5
Total Onsite Emissions	59.2	0.2	2.8	89.5	19.3	3.8
Offsite						
Worker Travel, Delivery and Haul Trucks[a]						
-- Exhaust	106.1	0.25	9.4	162.4	3.8	3.6
-- Fugitive Dust	--	--	--	--	25.8	7.0
Transmission Line Construction						
-- Exhaust	159.3	0.59	9.67	312.3	0.3	0.3
-- Fugitive Dust	--	--	--	--	7.3	3.4
Total Offsite Emissions	265.4	1.10	19.1	474.6	36.4	17.0 13.4
Total Emissions	324.6	1.3	21.9	564.1	58.0	18.2

a. Offsite activities.

TABLE 3.1C-2
Peak Annual Emissions During Construction, Tons per Year

	NOx	SO2	VOC	CO	PM10	PM2.5	GHG[b]
Onsite							
Construction and Onsite Vehicle Exhaust	6.3	0.02	0.38	12.5	0.04	0.04	2,245
Fugitive Dust	--	--	--	--	2.4	0.43	--
Total Onsite Emissions	6.3	0.02	0.4	12.5	2.4	0.5	2,245
Offsite							
Worker Travel, Delivery and Haul Trucks[a]							
-- Exhaust	5.4	0.036	0.6	13.3	0.14	0.13	2,861
-- Fugitive Dust	--	--	--	--	2.1	0.57	--
Transmission Line Construction							
-- Exhaust	4.00	0.015	0.25	8.0	0.03	0.03	1,397
-- Fugitive Dust	--	--	--	--	0.3	0.1	--
Total Offsite Emissions	9.4	0.1	0.9	21.3	2.5	0.8	4,258
Total Emissions	15.7	0.1	1.3	33.8	4.9	1.3	6,504

a. Offsite activities.

b. Metric tons of CO_2e.

3.1C.2 Greenhouse Gas Emissions During Construction

Greenhouse gas emissions (GHG) during construction were also evaluated. Total GHG emissions over the 22-month construction period are summarized in Table 3.1C-3 below. Detailed emissions calculations are provided in Attachment 3.1C-1.

TABLE 3.1C-3

GHG Emissions During the Construction Period, MT

	CO_2	CH_4	N_2O	CO_2e
Onsite				
Construction and Onsite Vehicle Exhaust	3,228	0.85	0.00	3,249
Offsite				
Worker Travel, Delivery and Haul Trucks	3,507	0.11	0.00	3,510
Transmission Line Construction	1,387	0.39	0.00	1,397
Total Emissions	8,123	1.35	0.00	8,157

3.1C.3 Air Quality Impact Analysis

A dispersion modeling analysis was conducted based on the emissions discussed above using the approach discussed in the modeling protocol submitted to the MDAQMD and CEC (see Appendix 3.1D).

As shown below in Table 3.1C-4, the results of the analysis indicate that construction activities are not expected to cause or contribute to exceedances of state or federal standards for criteria pollutants, with the exception of the state PM_{10}standards . For this pollutant and averaging periods, existing background concentrations already exceed state standards. The best available emission control techniques will be used to minimize emissions during construction. The project construction impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards.

A health risk assessment of construction impacts was performed in accordance with OEHHA guidance, which requires adjusting the 30-year lifetime dosage to an exposure period equal to that of the construction Period. At the point of maximum impact (along the property fenceline), the cancer risk approximately 0.03 in one million. This is well below the significance threshold of 10 in one million. Because the offsite DPM impacts fall off sharply with distance from the project fenceline, the residential risk at the nearest residential receptor, approximately 0.75 mile away, is also expected to be below this significance threshold.

The adjacent Blythe Energy Project will be in operation during the construction of SEP, so potential cumulative impacts have also been evaluated. Because the construction impacts are so localized, they are not expected to overlap with any areas that are significantly impacted by BEP.

Table 3.1C-4
Modeled Maximum Impacts During the Construction Period[a]

Pollutant	Averaging Time	Maximum Impact, SEP (μg/m^3)	Maximum Impact, BEP[d] (μg/m^3)	Background (μg/m^3)	Total Impact (μg/m^3)	State Standard (μg/m^3)	Federal Standard (μg/m^3)
NO_2	1-hour[b]	130.7	4.8	77.1	196.2	339	--
	Annual	3.6	0.1	13.2	16.8	57	100
SO_2	1-hour	1.9	0.8	22.9	24.8	655	--
	3-hour	1.6	0.7	22.6	24.2	--105	196--
	24-hour	0.35	0.25	2.6	3.0		
CO	1-hour	1,009.2	5.1	4,000	5,009	23,000	40,000
	8-hour	504.6	2.1	1,698	2,203	10,000	10,000
PM_{10}	24-hour	17.1	0.8	127	144.2	50	150
	Annual	1.3	0.1	22.1	23.5	20	--
$PM_{2.5}$[c]	24-hour	2.8	0.8	13.8	16.6	--	35
	Annual	0.2	0.1	6.5	6.8	12	12

a. Impacts shown are conservative because they include construction of the substation that is no longer part of the proposed project.
b. Only compliance with the state 1-hour NO_2 and SO_2 standards is evaluated. The federal 1-hour average standards for these pollutants are 3-year statistically based standards, while the construction period will last for less than 2 years.
c. 24-hr $PM_{2.5}$ background concentration reflects 3-year average of the 98th percentile values based on form of standard.
d. BEP impact at location of maximum SEP construction impact. Combined concentration does not necessarily equal the sum of the individual concentrations because the individual maxima may occur during different hours at the same receptor.

Attachment 3.1C-1

Detailed Construction Emissions Calculations from CalEEMod

Maximum Daily Emissions During Construction (lbs/day)						
	NOx	**CO**	**VOC**	**SOx**	**PM10**	**PM2.5**
Onsite						
Off-Road Equipment and Onsite Vehicle Combustion [1]	59.19	89.47	2.77	0.18	0.28	0.28
Fugitive Dust, Project Site-Construction [2]					13.61	1.36
Wind Erosion, Project Site Construction [2]					0.83	0.33
Soil Movement, Project Site Construction - Fugitive Dust [2]					4.61	1.84
Total Onsite Emission (Project Site Construction)	59.2	89.5	2.8	0.2	19.3	3.8
Offsite						
Transmission Line Construction						
Off-Road Equipment and Vehicle Combustion [3]	151.0	298.2	8.9	0.5	0.9	0.9
Fugitive Dust [4]					3.3	1.6
Wind Erosion [4]					0.8	0.3
Worker Travel						
Project Site Workforce, Combustion [5]	11.01	94.38	3.73	0.21	0.11	0.10
Project Site Workforce - Fugitive Dust					17.52	4.67
T-Line Workforce, Combustion [6]	1.05	8.97	0.35	0.02	0.01	0.01
T-Line Workforce - Fugitive Dust					1.67	0.44
Delivery Trucks						
Project Site Deliveries, Combustion [5]	23.86	17.06	1.38	0.08	0.73	0.67
Project Site Deliveries - Fugitive Dust					2.52	0.72
T-Line Deliveries, Combustion [6]	7.16	5.12	0.41	0.02	0.22	0.20
T-Line Deliveries - Fugitive Dust					0.75	0.22
Haul Trucks						
Project Site Haul Trucks, Combustion [5]	71.28	50.93	4.34	0.25	2.09	1.92
Project Site Haul Trucks - Fugitive Dust					5.79	1.60
Total Offsite Emissions						
Total Offsite Emissions, Project Site Construction	106.1	162.4	9.4	0.5	28.8	9.7
Total Offsite Emissions, T-Line Construction [7]	159.2	312.3	9.7	0.6	7.6	3.7
Total Offsite Emissions	265.4	474.6	19.1	1.1	36.4	13.4
Maximum Daily Emissions	324.6	564.1	21.9	1.3	55.7	17.2

Notes:

1. Includes on-site construction activity. Maximum emissions occur in month 11.
2. Includes on-site construction activity. Maximum onsite fugitive dust emissions occur in month 13; wind erosion and soil movement dust emissions are taken from the same period.
3. Maximum transmission line construction emissions occur in month 11.
4. Maximum transmission line construction and vehicle fugitive emissions in month 11, wind erosion dust emissions are taken from the
5. Maximum project site construction emissions for worker travel in month 13, delivery trucks in month 10, and haul trucks in month 7.
6. Maximum T-line construction emissions for worker travel and delivery trucks in month 9.
7. 7-month T-line construction occurs during months 7 to 13

Peak Annual Emissions During Construction						
(tons/yr, rolling 12-month maximum)						
	NOx	**CO**	**VOC**	**SOx**	**PM10**	**PM2.5**
Onsite						
Off-Road Equipment and Onsite Vehicle Combustion [1]	6.32	12.48	0.38	0.02	0.04	0.04
Fugitive Dust, Project Site Construction [2]					1.38	0.03
Wind Erosion, Project Site Construction [2]					0.15	0.06
Soil Movement, Project Site Construction - Fugitive Dust [2]					0.84	0.34
Total Onsite Emission (Project Site Construction)	6.3	12.5	0.4	0.02	2.4	0.5
Offsite						
Transmission Line Construction						
T-Line Off-Road Equipment and Vehicle Combustion [4]	3.74	7.39	0.22	0.01	0.02	0.02
T-Line Construction Fugitive Dust [4]					0.08	0.04
T-Line Wind Erosion [4]					0.08	0.03
Worker Travel						
Project Site Workforce, Combustion [3]	1.14	10.20	0.39	0.02	0.01	0.01
Project Site Workforce - Fugitive Dust					1.69	0.45
T-Line Workforce, Combustion [5]	0.05	0.48	0.02	0.001	0.001	0.0005
T-Line Workforce - Fugitive Dust					0.08	0.02
Delivery Trucks						
Project Site Deliveries, Combustion (combustion) [3]	1.60	1.12	0.09	0.005	0.05	0.04
Project Site Deliveries - Fugitive Dust					0.16	0.05
T-Line Deliveries, Combustion [4]	0.21	0.15	0.01	0.00	0.01	0.01
T-Line Deliveries - Fugitive Dust					0.02	0.01
Haul Trucks						
Project Site Haul Trucks, Combustion [3]	2.67	1.99	0.17	0.01	0.08	0.07
Project Site Haul Trucks - Fugitive Dust					0.22	0.06
Total Offsite Emissions						
Total Offsite Emissions, Project Site Construction	5.4	13.3	0.6	0.04	2.2	0.7
Total Offsite Emissions, T-Line Construction [4]	4.0	8.0	0.3	0.0	0.3	0.1
Total Offsite Emissions	9.4	21.3	0.9	0.1	2.5	0.8
Maximum Annual Emissions	15.7	33.8	1.3	0.1	4.9	1.3

1. Includes on-site construction activity. Maximum 12-month emissions occur from months 4 to 15
2. Includes on-site construction activity. Maximum 12-month emissions occur from months 7 to 18, wind erosion and soil movement dust emissions are taken from the same period.
3. Maximum 12-month emissions for worker travel from months 7 to 18, delivery trucks from months 2 to 13, and haul trucks from months 1 to 12
4. 7-month total transmission line construction emission from months 7 to 13 of the 22-month construction period

Short Term Impacts (24 hours and less)					
Daily working hours (hrs/day)	10				
	NOx	CO	SOx	PM10	PM2.5
Project Site Construction Emissions					
Off Road Equipment and Onsite Vehicle Combustion (lbs/day)	59.19	89.47	0.18	0.28	0.28
Off Road Equipment and Onsite Vehicle Combustion (lbs/hr)	5.92	8.95	0.02	0.03	0.03
Off Road Equipment and Onsite Vehicle Combustion (g/sec)	0.75	1.13	0.002	0.00	0.00
Off Road Equipment and Onsite Vehicle Fugitive Dust (lb/day)				13.61	1.36
Off Road Equipment and Onsite Vehicle Fugitive Dust (lb/hr)				1.36	0.14
Off Road Equipment and Onsite Vehicle Fugitive Dust (g/sec)				0.17	0.02
Wind Erosion (lbs/day)				0.83	0.33
Wind Erosion (lbs/hr) [1]				0.035	0.014
Wind Erosion (g/sec)				0.004	0.002
Soil Movement Fugitive Dust (lbs/day)				4.61	1.84
Soil Movement Fugitive Dust (lbs/hr)				0.46	0.18
Soil Movement Fugitive Dust (g/sec)				0.06	0.02

Note:

1. Wind erosion occurs 24 hrs/day.

Construction of the Proposed SEP - Modeled emissions, Long - Term Impacts

Long Term Impacts (annual)					
Days/yr	365				
Hrs/day	24				
	NOx	CO	SOx	PM10	PM2.5
Project Site Construction Emissions					
Off Road Equipment and Onsite Vehicle (Combustion) (tons/yr)	6.32	12.48	0.02	0.04	0.04
Off Road Equipment and Onsite Vehicle (Combustion) (lbs/hr)	1.44	2.85	0.01	0.01	0.01
Off Road Equipment and Onsite Vehicle (Combustion) (g/sec)	0.1818	0.3591	0.0007	0.0012	1.17E-03
Off Road Equipment and Onsite Vehicle Fugitive Dust (tons/yr)				1.38	0.03
Off Road Equipment and Onsite Vehicle Fugitive Dust (lbs/hr)				0.31	0.01
Off Road Equipment and Onsite Vehicle Fugitive Dust (g/sec)				0.0396	9.76E-04
Wind Erosion (Fugitive Dust) (tons/yr)				0.15	0.06
Wind Erosion (Fugitive Dust) (lbs/hr)				0.03	0.01
Wind Erosion (Fugitive Dust) (g/sec)				4.31E-03	1.73E-03
Soil Movement Fugitive Dust (lbs/day)				0.84	0.34
Soil Movement Fugitive Dust (lbs/hr)				0.19	0.08
Soil Movement Fugitive Dust (g/sec)				2.42E-02	9.67E-03

Construction of the Proposed SEP - Greenhouse Gas Emission Calculations

Peak Annual GHG Emissions, Project Site Construction (MT/yr, rolling 12-month maximum)				
	CO2	CH4	N2O	CO2e
Off-Road Equipment and Onsite Vehicle	2,231	0.57	0.00	2,245
Worker Travel	1,513	0.09	0.00	1,515
Delivery Truck	477	0.002	0.00	477
Haul Truck	869	0.004	0.00	869
Total =	5,090	0.66	0.00	5,107

GHG Emissions, Project Site Construction (MT, Total for 22-month Construction Period)				
	CO2	CH4	N2O	CO2e
Off-Road Equipment and Onsite Vehicle	3,228	0.85	0.00	3,249
Worker Travel	1,857	0.11	0.00	1,860
Delivery Truck	525	0.00	0.00	526
Haul Truck	1,125	0.01	0.00	1,125
Total	6,735	0.97	0.00	6,759

GHG Emissions, Transmission Line Construction (MT, Total for 7-month Period)				
	CO2	CH4	N2O	CO2e
Off-Road Equipment and Onsite Vehicle	1,250	0.38	0.00	1,260
Worker Travel	72	0.00	0.00	72
Delivery Truck	65	0.0003	0.00	65
Total	1,387	0.39	0.00	1,397

Construction of the Proposed SEP Project Site - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
												ROG											
Onsite Off-Road Equipment	(tons/month)	1.80E-02	2.44E-02	1.98E-02	3.76E-02	3.62E-02	3.68E-02	2.64E-02	3.07E-02	2.77E-02	3.19E-02	2.73E-02	3.24E-02	3.32E-02	3.18E-02	2.71E-02	2.38E-02	2.50E-02	1.70E-02	1.32E-02	1.03E-02	9.67E-03	9.85E-03
Onsite Vehicle	(tons/month)	6.48E-05	8.06E-05	1.49E-04	1.38E-04	2.98E-04	4.06E-04	5.84E-04	3.37E-04	3.66E-04	4.18E-04	3.46E-04	3.84E-04	3.35E-04	2.76E-04	2.91E-04	2.48E-04	2.65E-04	2.46E-04	1.81E-04	7.45E-05	1.74E-05	7.69E-06
Onsite Off-Road + Onsite Vehicle	(tons/month)	1.81E-02	2.45E-02	1.99E-02	3.77E-02	3.65E-02	3.72E-02	2.70E-02	3.10E-02	2.81E-02	3.23E-02	2.76E-02	3.28E-02	3.35E-02	3.21E-02	2.74E-02	2.40E-02	2.53E-02	1.72E-02	1.34E-02	1.04E-02	9.69E-03	9.86E-03
Offsite Haul Truck	(tons/month)	4.76E-03	4.58E-03	9.88E-03	5.49E-03	1.83E-02	2.64E-02	4.76E-02	1.61E-02	1.54E-02	9.03E-03	4.18E-03	4.35E-03	4.35E-03	4.18E-03	4.52E-03	4.18E-03	8.36E-03	7.69E-03	8.36E-03	3.98E-03	0.00E+00	0.00E+00
Offsite Delivery Truck	(tons/month)	0.00E+00	1.60E-03	1.76E-03	1.68E-03	6.42E-03	1.01E-02	1.01E-02	9.04E-03	1.10E-02	1.58E-02	1.10E-02	9.45E-03	3.01E-03	1.44E-03	1.57E-03	1.44E-03	1.51E-03	1.51E-03	1.44E-03	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	4.34E-03	5.10E-03	9.24E-03	1.27E-02	1.66E-02	1.94E-02	2.17E-02	2.21E-02	2.51E-02	3.50E-02	3.53E-02	4.27E-02	4.27E-02	3.58E-02	3.75E-02	3.15E-02	2.91E-02	2.69E-02	1.62E-02	6.76E-03	2.67E-03	1.18E-03
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												0.35	0.36	0.37	0.38	0.37	0.35	0.33	0.32	0.30	0.28	0.26
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												0.35	0.37	0.38	0.38	0.37	0.36	0.34	0.32	0.30	0.29	0.26
Offsite Haul Truck	Rolling 12-month total (tons/year)												0.17	0.17	0.17	0.16	0.16	0.15	0.13	0.09	0.08	0.06	0.05
Offsite Delivery Truck	Rolling 12-month total (tons/year)												0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.07	0.06	0.05	0.03
Offsite Worker Travel	Rolling 12-month total (tons/year)												0.25	0.29	0.32	0.35	0.37	0.38	0.39	0.38	0.36	0.34	0.31
												NOx											
Onsite Off-Road Equipment	(tons/month)	0.30	0.40	0.33	0.64	0.62	0.61	0.44	0.50	0.45	0.52	0.44	0.53	0.54	0.54	0.44	0.39	0.41	0.28	0.21	0.17	0.17	0.16
Onsite Vehicle	(tons/month)	6.83E-04	8.94E-04	1.66E-03	8.79E-04	3.51E-03	5.09E-03	7.82E-03	3.58E-03	3.81E-03	3.87E-03	2.65E-03	2.62E-03	1.75E-03	1.39E-03	1.48E-03	1.31E-03	1.77E-03	1.65E-03	1.51E-03	5.89E-04	5.54E-05	2.44E-05
Onsite Off-Road + Onsite Vehicle	(tons/month)	0.30	0.40	0.33	0.64	0.62	0.61	0.45	0.51	0.46	0.53	0.45	0.53	0.54	0.55	0.44	0.39	0.41	0.28	0.21	0.17	0.17	0.16
Offsite Haul Truck	(tons/month)	0.0788	0.0758	0.1637	0.0545	0.3031	0.4365	0.7881	0.2528	0.2423	0.1422	0.0658	0.0685	0.0685	0.0658	0.0711	0.0658	0.1317	0.1212	0.1317	0.0585	0	0
Offsite Delivery Truck	(tons/month)	0.000	0.029	0.032	0.030	0.115	0.181	0.181	0.158	0.191	0.275	0.191	0.165	0.053	0.025	0.028	0.025	0.026	0.026	0.025	0.000	0.000	0.000
Offsite Worker Travel	(tons/month)	0.012	0.014	0.026	0.035	0.046	0.054	0.060	0.066	0.074	0.104	0.105	0.127	0.127	0.106	0.111	0.094	0.086	0.080	0.048	0.022	0.009	0.004
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												5.78	6.03	6.17	6.28	6.03	5.82	5.49	5.27	4.93	4.65	4.28
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												5.82	6.07	6.21	6.32	6.07	5.86	5.53	5.29	4.95	4.67	4.30
Offsite Haul Truck	Rolling 12-month total (tons/year)												2.67	2.66	2.65	2.56	2.57	2.40	2.08	1.43	1.23	0.99	0.85
Offsite Delivery Truck	Rolling 12-month total (tons/year)												1.55	1.60	1.60	1.59	1.59	1.50	1.34	1.19	1.03	0.84	0.56
Offsite Worker Travel	Rolling 12-month total (tons/year)												0.72	0.84	0.93	1.01	1.07	1.11	1.14	1.13	1.08	1.02	0.92
												CO											
Onsite Off-Road Equipment	(tons/month)	0.584	0.793	0.642	1.246	1.198	1.194	0.859	0.997	0.901	1.036	0.886	1.053	1.079	1.072	0.881	0.773	0.810	0.552	0.428	0.335	0.335	0.320
Onsite Vehicle	(tons/month)	1.14E-03	1.40E-03	2.58E-03	2.81E-03	4.98E-03	6.51E-03	8.82E-03	6.19E-03	6.83E-03	8.40E-03	7.54E-03	8.70E-03	8.08E-03	6.72E-03	7.05E-03	5.98E-03	5.97E-03	5.52E-03	3.72E-03	1.62E-03	4.90E-04	2.16E-04
Onsite Off-Road + Onsite Vehicle	(tons/month)	0.585	0.794	0.645	1.249	1.203	1.200	0.868	1.003	0.908	1.045	0.894	1.061	1.087	1.078	0.888	0.779	0.816	0.557	0.431	0.336	0.336	0.320
Offsite Haul Truck	(tons/month)	0.056	0.054	0.117	0.075	0.217	0.312	0.563	0.196	0.188	0.111	0.051	0.053	0.053	0.051	0.055	0.051	0.102	0.094	0.102	0.049	0.000	0.000
Offsite Delivery Truck	(tons/month)	0.000	0.020	0.022	0.021	0.079	0.124	0.124	0.113	0.136	0.196	0.136	0.118	0.038	0.018	0.020	0.018	0.019	0.019	0.018	0.000	0.000	0.000
Offsite Worker Travel	(tons/month)	0.109	0.128	0.233	0.319	0.417	0.487	0.546	0.587	0.666	0.929	0.936	1.135	1.134	0.951	0.995	0.838	0.773	0.714	0.429	0.191	0.075	0.033
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												11.39	11.89	12.16	12.40	11.93	11.54	10.90	10.47	9.81	9.24	8.52
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												11.46	11.96	12.24	12.48	12.02	11.63	10.99	10.55	9.88	9.31	8.58
Offsite Haul Truck	Rolling 12-month total (tons/year)												1.99	1.99	1.99	1.93	1.90	1.79	1.57	1.11	0.96	0.77	0.66
Offsite Delivery Truck	Rolling 12-month total (tons/year)												1.09	1.12	1.12	1.12	1.12	1.06	0.95	0.85	0.73	0.60	0.40
Offsite Worker Travel	Rolling 12-month total (tons/year)												6.49	7.52	8.34	9.10	9.62	9.98	10.20	10.09	9.69	9.10	8.20
												SO2											
Onsite Off-Road Equipment	(tons/month)	1.12E-03	1.51E-03	1.21E-03	2.37E-03	2.27E-03	2.31E-03	1.71E-03	1.97E-03	1.78E-03	2.05E-03	1.76E-03	2.08E-03	2.13E-03	2.09E-03	1.76E-03	1.55E-03	1.63E-03	1.07E-03	8.40E-04	6.60E-04	6.40E-04	6.00E-04
Onsite Vehicle	(tons/month)	3.37E-06	4.25E-06	7.86E-06	5.91E-06	1.57E-05	2.16E-05	3.14E-05	1.98E-05	2.13E-05	2.41E-05	1.97E-05	2.17E-05	1.88E-05	1.55E-05	1.63E-05	1.40E-05	1.51E-05	1.40E-05	1.05E-05	4.86E-06	1.17E-06	5.21E-07
Onsite Off-Road + Onsite Vehicle	(tons/month)	1.12E-03	1.51E-03	1.22E-03	2.38E-03	2.29E-03	2.33E-03	1.74E-03	1.99E-03	1.80E-03	2.07E-03	1.78E-03	2.10E-03	2.15E-03	2.11E-03	1.78E-03	1.56E-03	1.65E-03	1.08E-03	8.50E-04	6.65E-04	6.41E-04	6.01E-04
Offsite Haul Truck	(tons/month)	2.70E-04	2.60E-04	5.60E-04	1.80E-04	1.04E-03	1.50E-03	2.70E-03	1.00E-03	9.50E-04	5.60E-04	2.60E-04	2.70E-04	2.70E-04	2.60E-04	2.80E-04	2.60E-04	5.20E-04	4.80E-04	5.20E-04	2.60E-04	0.00E+00	0.00E+00
Offsite Delivery Truck	(tons/month)	0.00E+00	9.00E-05	1.00E-04	9.00E-05	3.50E-04	5.50E-04	5.50E-04	5.50E-04	6.60E-04	9.50E-04	6.60E-04	5.70E-04	1.80E-04	9.00E-05	1.00E-04	9.00E-05	9.00E-05	9.00E-05	9.00E-05	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	2.00E-04	2.40E-04	4.30E-04	5.90E-04	7.70E-04	9.00E-04	1.00E-03	1.22E-03	1.38E-03	1.93E-03	1.94E-03	2.35E-03	2.35E-03	1.97E-03	2.06E-03	1.74E-03	1.60E-03	1.48E-03	8.90E-04	4.40E-04	1.80E-04	8.00E-05
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Offsite Haul Truck	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Offsite Delivery Truck	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Offsite Worker Travel	Rolling 12-month total (tons/year)												0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02

Construction of the Proposed SEP Project Site - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
													PM10										
Onsite Off-Road Equipment	(tons/month)	0.002	0.003	0.003	0.004	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Onsite Vehicle	(tons/month)	1.83E-05	2.45E-05	4.54E-05	2.04E-05	9.70E-05	1.42E-04	2.22E-04	9.89E-05	1.05E-04	1.03E-04	6.63E-05	6.22E-05	3.59E-05	2.76E-05	2.96E-05	2.68E-05	4.17E-05	3.88E-05	3.90E-05	1.62E-05	5.86E-07	2.61E-07
Onsite Off-Road + Onsite Vehicle	(tons/month)	2.43E-03	3.03E-03	2.63E-03	4.36E-03	4.63E-03	4.37E-03	2.80E-03	3.13E-03	2.84E-03	3.25E-03	2.78E-03	3.28E-03	3.34E-03	3.23E-03	2.72E-03	2.39E-03	2.51E-03	1.72E-03	1.36E-03	1.05E-03	9.91E-04	9.80E-04
Offsite Haul Truck	(tons/month)	2.30E-03	2.21E-03	4.77E-03	1.48E-03	8.83E-03	1.27E-02	2.30E-02	7.54E-03	7.22E-03	4.24E-03	1.96E-03	2.04E-03	2.04E-03	1.96E-03	2.12E-03	1.96E-03	3.93E-03	3.61E-03	3.93E-03	1.93E-03	0.00E+00	0.00E+00
Offsite Delivery Truck	(tons/month)	0.00E+00	8.70E-04	9.50E-04	9.10E-04	3.48E-03	5.47E-03	5.47E-03	4.82E-03	5.84E-03	8.40E-03	5.84E-03	5.04E-03	1.61E-03	7.70E-04	8.40E-04	7.70E-04	8.00E-04	8.00E-04	7.70E-04	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	1.10E-04	1.30E-04	2.30E-04	3.20E-04	4.10E-04	4.80E-04	5.40E-04	6.30E-04	7.10E-04	9.90E-04	1.00E-03	1.21E-03	1.21E-03	1.02E-03	1.06E-03	9.00E-04	8.30E-04	7.60E-04	4.60E-04	2.20E-04	9.00E-05	4.00E-05
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
Offsite Haul Truck	Rolling 12-month total (tons/year)												0.08	0.08	0.08	0.08	0.08	0.07	0.06	0.04	0.04	0.03	0.03
Offsite Delivery Truck	Rolling 12-month total (tons/year)												0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.03	0.03	0.02
Offsite Worker Travel	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Onsite Fugitive (Off-Road)	(tons/month)	8.53E-03	8.14E-03	8.92E-03	1.14E-02	8.14E-03	8.53E-03	2.84E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Onsite Fugitive (Onsite Vehicle)	(tons/month)	1.48E-02	1.70E-02	3.15E-02	4.10E-02	5.69E-02	6.91E-02	8.65E-02	8.47E-02	9.46E-02	1.25E-01	1.23E-01	1.49E-01	1.48E-01	1.24E-01	1.30E-01	1.10E-01	1.04E-01	9.59E-02	5.98E-02	2.97E-02	1.08E-02	4.77E-03
Onsite Off-Road + Onsite Vehicle	(tons/month)	0.02	0.03	0.04	0.05	0.07	0.08	0.09	0.09	0.10	0.13	0.12	0.15	0.15	0.12	0.13	0.11	0.10	0.10	0.06	0.03	0.01	0.00
Offsite Fugitive - Haul Truck	(tons/month)	0.01	0.01	0.01	0.00	0.02	0.03	0.06	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Offsite Fugitive - Delivery Truck	(tons/month)	0.00	0.00	0.00	0.00	0.01	0.02	0.02	0.02	0.02	0.03	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Worker Travel	(tons/month)	0.02	0.02	0.03	0.05	0.06	0.07	0.08	0.10	0.11	0.16	0.16	0.19	0.19	0.16	0.17	0.14	0.13	0.12	0.07	0.04	0.01	0.01
Onsite Fugitive (Off-Road)	Rolling 12-month total (tons/year)												0.06	0.05	0.04	0.03	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Off-Road + Onsite Veh	Rolling 12-month total (tons/year)												0.95	1.08	1.18	1.27	1.33	1.37	1.38	1.35	1.30	1.21	1.09
Offsite Fugitive - Haul Truck	Rolling 12-month total (tons/year)												0.22	0.22	0.22	0.22	0.22	0.21	0.18	0.13	0.11	0.09	0.08
Offsite Fugitive - Delivery Truck	Rolling 12-month total (tons/year)												0.15	0.16	0.16	0.16	0.16	0.15	0.14	0.12	0.11	0.09	0.06
Offsite Fugitive - Worker Travel	Rolling 12-month total (tons/year)												1.04	1.21	1.35	1.49	1.58	1.65	1.69	1.68	1.62	1.52	1.38
													PM2.5										
Onsite Off-Road Equipment	(tons/month)	0.002	0.003	0.003	0.004	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Onsite Vehicle	(tons/month)	1.68E-05	2.25E-05	4.18E-05	1.88E-05	8.93E-05	1.31E-04	2.04E-04	9.09E-05	9.64E-05	9.51E-05	6.11E-05	5.73E-05	3.31E-05	2.54E-05	2.72E-05	2.47E-05	3.83E-05	3.57E-05	3.59E-05	1.49E-05	5.21E-07	2.61E-07
Onsite Off-Road + Onsite Vehicle	(tons/month)	2.43E-03	3.03E-03	2.62E-03	4.36E-03	4.62E-03	4.36E-03	2.78E-03	3.12E-03	2.84E-03	3.25E-03	2.77E-03	3.28E-03	3.33E-03	3.23E-03	2.72E-03	2.38E-03	2.51E-03	1.72E-03	1.36E-03	1.04E-03	9.91E-04	9.80E-04
Offsite Haul Truck	(tons/month)	2.11E-03	2.03E-03	4.39E-03	1.36E-03	8.12E-03	1.17E-02	2.11E-02	6.93E-03	6.64E-03	3.90E-03	1.81E-03	1.88E-03	1.88E-03	1.81E-03	1.95E-03	1.81E-03	3.61E-03	3.32E-03	3.61E-03	1.77E-03	0.00E+00	0.00E+00
Offsite Delivery Truck	(tons/month)	0.00E+00	8.00E-04	8.80E-04	8.40E-04	3.20E-03	5.03E-03	5.03E-03	4.43E-03	5.38E-03	7.73E-03	5.38E-03	4.64E-03	1.48E-03	7.10E-04	7.70E-04	7.10E-04	7.40E-04	7.40E-04	7.10E-04	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	1.00E-04	1.20E-04	2.10E-04	2.90E-04	3.80E-04	4.40E-04	4.90E-04	5.80E-04	6.50E-04	9.10E-04	9.20E-04	1.12E-03	1.12E-03	9.40E-04	9.80E-04	8.20E-04	7.60E-04	7.00E-04	4.20E-04	2.00E-04	8.00E-05	4.00E-05
Onsite Off-Road Equipment	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
Offsite Haul Truck	Rolling 12-month total (tons/year)												0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.04	0.03	0.03	0.02
Offsite Delivery Truck	Rolling 12-month total (tons/year)												0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.02	0.02
Offsite Worker Travel	Rolling 12-month total (tons/year)												0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Onsite Fugitive (Off-Road)	(tons/month)	9.20E-04	8.80E-04	9.60E-04	1.23E-03	8.80E-04	9.20E-04	3.10E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Onsite Fugitive (Onsite Vehicle)	(tons/month)	1.48E-03	1.77E-03	3.23E-03	4.17E-03	5.99E-03	7.34E-03	9.12E-03	8.90E-03	1.00E-02	1.33E-02	1.29E-02	1.53E-02	1.50E-02	1.25E-02	1.31E-02	1.11E-02	1.05E-02	9.66E-03	6.06E-03	2.97E-03	1.08E-03	4.77E-04
Onsite Off-Road + Onsite Vehicle	(tons/month)	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Offsite Fugitive - Haul Truck	(tons/month)	1.74E-03	1.67E-03	3.60E-03	1.11E-03	6.67E-03	9.61E-03	1.74E-02	6.41E-03	6.14E-03	3.60E-03	1.67E-03	1.74E-03	1.74E-03	1.67E-03	1.80E-03	1.67E-03	3.34E-03	3.07E-03	3.34E-03	1.67E-03	0.00E+00	0.00E+00
Offsite Fugitive - Delivery Truck	(tons/month)	0.00E+00	7.50E-04	8.20E-04	7.80E-04	2.98E-03	4.69E-03	4.69E-03	4.69E-03	5.69E-03	8.18E-03	5.69E-03	4.91E-03	1.56E-03	7.50E-04	8.20E-04	7.50E-04	7.80E-04	7.80E-04	7.50E-04	0.00E+00	0.00E+00	0.00E+00
Offsite Fugitive - Worker Travel	(tons/month)	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.04	0.04	0.04	0.03	0.03	0.02	0.01	0.00	0.00
Onsite Fugitive (Off-Road)	Rolling 12-month total (tons/year)												0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Off-Road + Onsite Veh	Rolling 12-month total (tons/year)												0.10	0.11	0.12	0.13	0.14	0.14	0.14	0.14	0.13	0.12	0.11
Offsite Fugitive - Haul Truck	Rolling 12-month total (tons/year)												0.06	0.06	0.06	0.06	0.06	0.06	0.05	0.04	0.03	0.03	0.02
Offsite Fugitive - Delivery Truck	Rolling 12-month total (tons/year)												0.04	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.03	0.02	0.02
Offsite Fugitive - Worker Travel	Rolling 12-month total (tons/year)												0.28	0.32	0.36	0.40	0.42	0.44	0.45	0.45	0.43	0.41	0.37
													CO2										
Onsite Off-Road Equipment	(MT/month)	104.27	141.02	112.95	219.05	210.15	212.82	155.16	178.48	161.37	185.58	159.27	189.01	193.35	188.89	159.12	139.94	146.60	97.68	76.72	59.70	57.28	54.87
Onsite Vehicle	(MT/month)	2.87E-01	3.58E-01	6.68E-01	4.73E-01	1.35E+00	1.87E+00	2.77E+00	1.63E+00	1.76E+00	1.94E+00	1.54E+00	1.68E+00	1.41E+00	1.16E+00	1.22E+00	1.05E+00	1.17E+00	1.08E+00	8.34E-01	3.75E-01	7.88E-02	3.47E-02
Onsite Off-Road + Onsite Vehicle	(MT/month)	104.55	141.38	113.62	219.52	211.49	214.69	157.93	180.11	163.14	187.52	160.81	190.69	194.76	190.06	160.34	140.99	147.77	98.77	77.56	60.08	57.36	54.90
Offsite Haul Truck	(MT/month)	24.73	23.78	51.36	16.12	95.12	136.97	247.31	89.72	85.98	50.46	23.36	24.30	24.30	23.36	25.23	23.36	46.73	42.99	46.73	22.96	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	7.93	8.69	8.31	31.72	49.85	49.85	49.02	59.42	85.41	59.42	51.25	16.34	7.80	8.54	7.80	8.17	8.17	7.80	0.00	0.00	0.00
Offsite Worker Travel	(MT/month)	14.98	17.60	31.93	43.80	57.21	66.85	74.92	87.44	99.11	138.28	139.36	168.94	168.79	141.57	148.11	124.67	115.11	106.25	63.92	30.61	12.10	5.32
Onsite Off-Road Equipment	Rolling 12-month total (MT/year)												2,029	2,118	2,166	2,212	2,133	2,070	1,954	1,876	1,757	1,653	1,522
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (MT/year)												2,045	2,136	2,184	2,231	2,153	2,089	1,973	1,893	1,772	1,667	1,534
Offsite Haul Truck	Rolling 12-month total (MT/year)												869	869	868	842	849	801	707	507	440	354	303
Offsite Delivery Truck	Rolling 12-month total (MT/year)												461	477	477	477	476	453	411	369	320	261	175
Offsite Worker Travel	Rolling 12-month total (MT/year)												940	1,094	1,218	1,334	1,415	1,473	1,513	1,502	1,445	1,358	1,225

Construction of the Proposed SEP Project Site - Monthly and Annual Emission Calculations

Project Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
													CH4										
Onsite Off-Road Equipment	(MT/month)	0.031	0.042	0.034	0.058	0.056	0.056	0.038	0.046	0.042	0.048	0.041	0.049	0.051	0.047	0.040	0.035	0.036	0.029	0.023	0.018	0.017	0.017
Onsite Vehicle	(tons/month)	6.72E-06	8.00E-06	1.46E-05	1.79E-05	2.70E-05	3.30E-05	4.03E-05	3.72E-05	4.17E-05	5.57E-05	5.42E-05	6.49E-05	6.36E-05	5.33E-05	5.57E-05	4.70E-05	4.43E-05	4.09E-05	2.55E-05	1.17E-05	4.30E-06	1.89E-06
Onsite Off-Road + Onsite Vehicle	(MT/month)	0.03	0.04	0.03	0.06	0.06	0.06	0.04	0.05	0.04	0.05	0.04	0.05	0.05	0.05	0.04	0.03	0.04	0.03	0.02	0.02	0.02	0.02
Offsite Haul Truck	(MT/month)	1.20E-04	1.20E-04	2.60E-04	9.00E-05	4.80E-04	6.90E-04	1.24E-03	4.30E-04	4.10E-04	2.40E-04	1.10E-04	1.20E-04	1.20E-04	1.10E-04	1.20E-04	1.10E-04	2.20E-04	2.00E-04	2.20E-04	1.10E-04	0.00E+00	0.00E+00
Offsite Delivery Truck	(MT/month)	0.00E+00	4.00E-05	4.00E-05	4.00E-05	1.60E-04	2.50E-04	2.50E-04	2.30E-04	2.70E-04	3.90E-04	2.70E-04	2.40E-04	8.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	4.00E-05	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	(MT/month)	8.90E-04	1.04E-03	1.89E-03	2.59E-03	3.39E-03	3.96E-03	4.44E-03	4.94E-03	5.60E-03	7.81E-03	7.87E-03	9.54E-03	9.53E-03	8.00E-03	8.36E-03	7.04E-03	6.50E-03	6.00E-03	3.61E-03	1.66E-03	6.60E-04	2.90E-04
Onsite Off-Road Equipment	Rolling 12-month total (MT/year)												0.54	0.56	0.56	0.57	0.55	0.53	0.50	0.48	0.46	0.43	0.40
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (MT/year)												1	1	1	1	1	1	1	0	0	0	0
Offsite Haul Truck	Rolling 12-month total (MT/year)												4.31E-03	4.31E-03	4.30E-03	4.16E-03	4.18E-03	3.92E-03	3.43E-03	2.41E-03	2.09E-03	1.68E-03	1.44E-03
Offsite Delivery Truck	Rolling 12-month total (MT/year)												2.18E-03	2.26E-03	2.26E-03	2.26E-03	2.26E-03	2.14E-03	1.93E-03	1.72E-03	1.49E-03	1.22E-03	8.30E-04
Offsite Worker Travel	Rolling 12-month total (MT/year)												5.40E-02	6.26E-02	6.96E-02	7.60E-02	8.05E-02	8.36E-02	8.56E-02	8.48E-02	8.15E-02	7.66E-02	6.91E-02
													N2O										
Onsite Off-Road Equipment	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Vehicle	(tons/month)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Onsite Off-Road + Onsite Vehicle	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Haul Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Worker Travel	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road Equipment	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (MT/year)												0	0	0	0	0	0	0	0	0	0	0
Offsite Haul Truck	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Worker Travel	Rolling 12-month total (MT/year)												0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
													CO2e										
Onsite Off-Road Equipment	(MT/month)	105.04	142.07	113.79	220.49	211.54	214.22	156.12	179.62	162.41	186.77	160.29	190.23	194.61	190.06	160.11	140.80	147.51	98.42	77.30	60.15	57.71	55.29
Onsite Vehicle	(tons/month)	2.87E-01	3.58E-01	6.69E-01	4.73E-01	1.35E+00	1.87E+00	2.77E+00	1.63E+00	1.76E+00	1.94E+00	1.54E+00	1.68E+00	1.41E+00	1.16E+00	1.23E+00	1.05E+00	1.17E+00	1.09E+00	8.35E-01	3.76E-01	7.89E-02	3.47E-02
Onsite Off-Road + Onsite Vehicle	(MT/month)	105.33	142.43	114.46	220.97	212.88	216.09	158.89	181.26	164.17	188.72	161.83	191.91	196.03	191.22	161.33	141.86	148.68	99.50	78.13	60.53	57.79	55.33
Offsite Haul Truck	(MT/month)	24.73	23.78	51.37	16.12	95.13	136.99	247.34	89.73	85.99	50.47	23.37	24.30	24.30	23.37	25.24	23.37	46.73	42.99	46.73	22.96	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	7.93	8.69	8.31	31.72	49.85	49.85	49.03	59.42	85.42	59.42	51.25	16.34	7.80	8.54	7.80	8.17	8.17	7.80	0.00	0.00	0.00
Offsite Worker Travel	(MT/month)	15.01	17.63	31.98	43.86	57.30	66.95	75.03	87.56	99.25	138.47	139.56	169.18	169.03	141.77	148.32	124.84	115.27	106.40	64.01	30.65	12.12	5.33
Onsite Off-Road Equipment	Rolling 12-month total (MT/year)												2,043	2,132	2,180	2,226	2,147	2,083	1,967	1,888	1,769	1,664	1,532
Onsite Off-Road + Onsite Vehicle	Rolling 12-month total (MT/year)												2,059	2,150	2,198	2,245	2,166	2,102	1,985	1,905	1,784	1,678	1,544
Offsite Haul Truck	Rolling 12-month total (MT/year)												869	869	868	842	850	801	707	507	440	354	303
Offsite Delivery Truck	Rolling 12-month total (MT/year)												461	477	477	477	476	453	411	369	320	261	175
Offsite Worker Travel	Rolling 12-month total (MT/year)												942	1,096	1,220	1,336	1,417	1,475	1,515	1,504	1,447	1,360	1,226

Construction of the Proposed SEP Transmission Line - Monthly and Annual Emission Calculations

Project Month		**7**	**8**	**9**	**10**	**11**	**12**	**13**
					ROG			
T-Line Site Off-Road Equipment	(tons/month)	0.00E+00	9.53E-03	6.56E-03	4.84E-02	8.89E-02	5.93E-02	8.17E-03
T-Line Site Vehicle	(tons/month)	1.11E-06	1.82E-05	5.58E-05	5.93E-05	5.37E-05	1.35E-05	1.01E-05
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	1.11E-06	9.55E-03	6.62E-03	4.85E-02	8.90E-02	5.93E-02	8.18E-03
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.00E+00	0.00E+00	4.11E-03	4.09E-03	3.83E-03	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	1.70E-04	2.80E-03	3.69E-03	4.25E-03	3.69E-03	2.05E-03	1.54E-03
T-Line Site Off-Road Equipment	7-month total (tons/year)							0.22
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							0.22
Offsite Haul Truck								0.00
Offsite Delivery Truck	7-month total (tons/year)							0.01
Offsite Worker Travel	7-month total (tons/year)							0.02
					NOx			
T-Line Site Off-Road Equipment	(tons/month)	0.00	0.15	0.11	0.82	1.51	1.01	0.13
T-Line Site Vehicle	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	0.00	0.15	0.11	0.82	1.51	1.01	0.13
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.000	0.000	0.072	0.072	0.067	0.000	0.000
Offsite Worker Travel	(tons/month)	0.000	0.008	0.011	0.013	0.011	0.006	0.005
T-Line Site Off-Road Equipment	7-month total (tons/year)							3.73
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							3.74
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							0.21
Offsite Worker Travel	7-month total (tons/year)							0.05
					CO			
T-Line Site Off-Road Equipment	(tons/month)	0.000	0.310	0.223	1.609	2.981	1.996	0.266
T-Line Site Vehicle	(tons/month)	0.000	0.000	0.001	0.001	0.001	0.000	0.000
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	0.000	0.310	0.224	1.611	2.982	1.997	0.266
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.000	0.000	0.051	0.051	0.048	0.000	0.000
Offsite Worker Travel	(tons/month)	0.004	0.074	0.098	0.113	0.098	0.054	0.041
T-Line Site Off-Road Equipment	7-month total (tons/year)							7.38
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							7.39
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							0.15
Offsite Worker Travel	7-month total (tons/year)							0.48

Construction of the Proposed SEP Transmission Line - Monthly and Annual Emission Calculations

Project Month		7	8	9	10	11	12	13
					SO2			
T-Line Site Off-Road Equipment	(tons/month)	0.00E+00	5.80E-04	4.00E-04	2.93E-03	5.42E-03	3.64E-03	5.00E-04
T-Line Site Vehicle	(tons/month)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	6.51E-08	5.81E-04	4.03E-04	2.93E-03	5.42E-03	3.64E-03	5.01E-04
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.00E+00	0.00E+00	2.50E-04	2.50E-04	2.30E-04	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	1.00E-05	1.50E-04	2.00E-04	2.30E-04	2.00E-04	1.10E-04	8.00E-05
T-Line Site Off-Road Equipment	7-month total (tons/year)							0.01
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							0.01
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							0.00
Offsite Worker Travel	7-month total (tons/year)							0.00
					PM10			
T-Line Site Off-Road Equipment	(tons/month)	0.00E+00	9.50E-04	6.50E-04	4.80E-03	8.89E-03	5.97E-03	8.20E-04
T-Line Site Vehicle	(tons/month)	0.00E+00	5.21E-07	1.74E-05	1.75E-05	1.64E-05	3.95E-07	2.63E-07
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	0.00E+00	9.51E-04	6.67E-04	4.82E-03	8.91E-03	5.97E-03	8.20E-04
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.00E+00	0.00E+00	2.19E-03	2.18E-03	2.05E-03	0.00E+00	0.00E+00
Offsite Worker Travel	(tons/month)	0.00E+00	8.00E-05	1.00E-04	1.20E-04	1.00E-04	6.00E-05	4.00E-05
T-Line Site Off-Road Equipment	7-month total (tons/year)							0.02
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							0.02
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							0.01
Offsite Worker Travel	7-month total (tons/year)							0.00
T-Line Site Fugitive (Off-Road)	(tons/month)	0.00E+00	2.84E-03	0.00E+00	0.00E+00	2.94E-02	3.38E-02	2.84E-03
T-Line Site Fugitive (T-Line Site Vehicle)	(tons/month)	7.95E-05	1.59E-03	3.39E-03	3.70E-03	3.38E-03	1.16E-03	8.75E-04
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	7.95E-05	4.43E-03	3.39E-03	3.70E-03	3.28E-02	3.50E-02	3.71E-03
Offsite Fugitive - Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	(tons/month)	0.00E+00	0.00E+00	7.44E-03	7.41E-03	6.94E-03	0.00E+00	0.00E+00
Offsite Fugitive - Worker Travel	(tons/month)	6.20E-04	1.24E-02	1.64E-02	1.88E-02	1.64E-02	9.08E-03	6.83E-03
T-Line Site Fugitive (Off-Road)	7-month total (tons/year)							0.07
T-Line Site Fugitive - Off-Road + T-Line Site Veh	7-month total (tons/year)							0.08
Offsite Fugitive - Haul Truck	7-month total (tons/year)							0.00
Offsite Fugitive - Delivery Truck	7-month total (tons/year)							0.02
Offsite Fugitive - Worker Travel	7-month total (tons/year)							0.08

Construction of the Proposed SEP Transmission Line - Monthly and Annual Emission Calculations

Project Month		**7**	**8**	**9**	**10**	**11**	**12**	**13**
					PM2.5			
T-Line Site Off-Road Equipment	(tons/month)	0.0E+00	9.5E-04	6.5E-04	4.8E-03	8.9E-03	6.0E-03	8.2E-04
T-Line Site Vehicle	(tons/month)	0.0E+00	4.6E-07	1.6E-05	1.6E-05	1.5E-05	3.3E-07	2.6E-07
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	0.0E+00	9.5E-04	6.7E-04	4.8E-03	8.9E-03	6.0E-03	8.2E-04
Offsite Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(tons/month)	0.0E+00	0.0E+00	2.0E-03	2.0E-03	1.9E-03	0.0E+00	0.0E+00
Offsite Worker Travel	(tons/month)	0.0E+00	7.0E-05	1.0E-04	1.1E-04	1.0E-04	5.0E-05	4.0E-05
T-Line Site Off-Road Equipment	7-month total (tons/year)							0.02
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							0.02
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							0.01
Offsite Worker Travel	7-month total (tons/year)							0.00
T-Line Site Fugitive (Off-Road)	(tons/month)	0.0E+00	3.1E-04	0.0E+00	0.0E+00	1.6E-02	1.9E-02	3.1E-04
T-Line Site Fugitive (T-Line Site Vehicle)	(tons/month)	8.0E-06	1.6E-04	3.4E-04	3.7E-04	3.4E-04	1.2E-04	8.7E-05
T-Line Site Off-Road + T-Line Site Vehicle	(tons/month)	8.0E-06	4.7E-04	3.4E-04	3.7E-04	1.6E-02	1.9E-02	4.0E-04
Offsite Fugitive - Haul Truck	(tons/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	(tons/month)	0.0E+00	0.0E+00	2.1E-03	2.1E-03	2.0E-03	0.0E+00	0.0E+00
Offsite Fugitive - Worker Travel	(tons/month)	0.00	0.00	0.00	0.01	0.00	0.00	0.00
T-Line Site Fugitive (Off-Road)	7-month total (tons/year)							0.04
T-Line Site Fugitive - Off-Road + T-Line Site Veh	7-month total (tons/year)							0.04
Offsite Fugitive - Haul Truck	7-month total (tons/year)							0.00
Offsite Fugitive - Delivery Truck	7-month total (tons/year)							0.01
Offsite Fugitive - Worker Travel	7-month total (tons/year)							0.02
					CO2			
T-Line Site Off-Road Equipment	(MT/month)	0.00	53.89	36.80	271.62	503.11	337.74	46.22
T-Line Site Vehicle	(MT/month)	0.004	0.072	0.267	0.281	0.256	0.053	0.040
T-Line Site Off-Road + T-Line Site Vehicle	(MT/month)	0.00	53.97	37.06	271.90	503.37	337.79	46.26
Offsite Haul Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	0.00	22.28	22.21	20.80	0.00	0.00
Offsite Worker Travel	(MT/month)	0.58	11.07	14.59	16.78	14.59	8.10	6.09
T-Line Site Off-Road Equipment	7-month total (tons/year)							1,249.38
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (tons/year)							1,250.35
Offsite Haul Truck	7-month total (tons/year)							0.00
Offsite Delivery Truck	7-month total (tons/year)							65.29
Offsite Worker Travel	7-month total (tons/year)							71.79

Construction of the Proposed SEP Transmission Line - Monthly and Annual Emission Calculations

Project Month		**7**	**8**	**9**	**10**	**11**	**12**	**13**
					CH4			
T-Line Site Off-Road Equipment	(MT/month)	0.000	0.017	0.011	0.083	0.154	0.104	0.014
T-Line Site Vehicle	(MT/month)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
T-Line Site Off-Road + T-Line Site Vehicle	(MT/month)	0.00	0.02	0.01	0.08	0.15	0.10	0.01
Offsite Haul Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00E+00	0.00E+00	1.00E-04	1.00E-04	1.00E-04	0.00E+00	0.00E+00
Offsite Worker Travel	(MT/month)	3.00E-05	6.30E-04	8.20E-04	9.50E-04	8.20E-04	4.60E-04	3.40E-04
T-Line Site Off-Road Equipment	7-month total (MT/year)							0.38
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (MT/year)							0.38
Offsite Haul Truck	7-month total (MT/year)							0.00
Offsite Delivery Truck	7-month total (MT/year)							0.00
Offsite Worker Travel	7-month total (MT/year)							0.00
					N2O			
T-Line Site Off-Road Equipment	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Vehicle	(MT/month)	0.000	0.000	0.000	0.000	0.000	0.000	0.000
T-Line Site Off-Road + T-Line Site Vehicle	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Haul Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Worker Travel	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road Equipment	7-month total (MT/year)							0.00
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (MT/year)							0.00
Offsite Haul Truck	7-month total (MT/year)							0.00
Offsite Delivery Truck	7-month total (MT/year)							0.00
Offsite Worker Travel	7-month total (MT/year)							0.00
					CO2e			
T-Line Site Off-Road Equipment	(MT/month)	0.00	54.31	37.08	273.70	506.96	340.33	46.58
T-Line Site Vehicle	(MT/month)	0.004	0.072	0.267	0.281	0.256	0.053	0.040
T-Line Site Off-Road + T-Line Site Vehicle	(MT/month)	0.00	54.38	37.35	273.98	507.22	340.38	46.62
Offsite Haul Truck	(MT/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	(MT/month)	0.00	0.00	22.28	22.21	20.80	0.00	0.00
Offsite Worker Travel	(MT/month)	0.58	11.08	14.61	16.80	14.61	8.11	6.10
T-Line Site Off-Road Equipment	7-month total (MT/year)							1,258.95
T-Line Site Off-Road + T-Line Site Vehicle	7-month total (MT/year)							1,259.93
Offsite Haul Truck	7-month total (MT/year)							0.00
Offsite Delivery Truck	7-month total (MT/year)							65.29
Offsite Worker Travel	7-month total (MT/year)							71.89

Construction of the Proposed SEP Project Site - Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	ROG (lbs/day)																					
Onsite Off-Road Equipment	1.64	2.32	1.72	3.42	3.45	3.34	2.40	2.79	2.77	2.77	2.73	2.82	3.02	3.03	2.36	2.27	2.27	1.55	1.25	0.90	0.97	0.90
Onsite Vehicle	0.01	0.01	0.01	0.01	0.03	0.04	0.05	0.03	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.02	0.02	0.01	0.00	0.00
Onsite Off-Road + Onsite Vehicle	1.64	2.33	1.74	3.43	3.48	3.38	2.45	2.82	2.81	2.81	2.77	2.86	3.06	3.06	2.39	2.30	2.30	1.57	1.27	0.90	0.97	0.90
Offsite Haul Truck	0.41	0.42	0.82	0.46	1.67	2.30	4.15	1.40	1.48	0.75	0.40	0.36	0.38	0.38	0.38	0.38	0.73	0.67	0.76	0.33	0.00	0.00
Offsite Delivery Truck	0.00	0.15	0.15	0.15	0.59	0.89	0.89	0.80	1.07	1.33	1.07	0.80	0.27	0.13	0.13	0.13	0.13	0.13	0.13	0.00	0.00	0.00
Offsite Worker Travel	0.45	0.56	0.92	1.32	1.81	2.02	2.26	2.34	2.91	3.54	4.10	4.32	4.51	3.96	3.79	3.49	3.08	2.84	1.79	0.69	0.31	0.13
	NOx (lbs/day)																					
Onsite Off-Road Equipment	26.84	38.23	28.92	58.01	58.86	55.29	39.84	45.72	45.45	45.45	44.44	45.89	49.15	51.80	38.47	37.02	37.02	25.37	20.21	14.43	17.02	14.43
Onsite Vehicle	0.06	0.08	0.14	0.07	0.31	0.43	0.67	0.30	0.36	0.32	0.25	0.21	0.15	0.12	0.12	0.12	0.15	0.14	0.13	0.05	0.01	0.00
Onsite Off-Road + Onsite Vehicle	26.90	38.31	29.05	58.08	59.17	55.72	40.51	46.03	45.81	45.77	44.69	46.10	49.30	51.92	38.58	37.14	37.17	25.51	20.34	14.48	17.03	14.44
Offsite Haul Truck	6.75	6.80	13.41	4.69	27.20	37.38	67.50	21.66	22.83	11.65	6.20	5.61	5.87	5.91	5.83	5.91	11.28	10.38	11.82	4.79	0.00	0.00
Offsite Delivery Truck	0.00	2.58	2.58	2.58	10.31	15.46	15.46	13.48	17.97	22.47	17.97	13.48	4.49	2.25	2.25	2.25	2.25	2.25	2.25	0.00	0.00	0.00
Offsite Worker Travel	1.00	1.23	2.04	2.92	4.00	4.46	5.00	5.45	6.79	8.24	9.55	10.07	10.51	9.24	8.82	8.14	7.17	6.62	4.17	1.71	0.78	0.31
	CO (lbs/day)																					
Onsite Off-Road Equipment	53.09	75.51	55.85	113.27	114.14	108.54	78.11	90.66	90.12	90.12	88.61	91.52	98.11	102.06	76.56	73.65	73.65	50.16	40.73	29.09	33.54	29.09
Onsite Vehicle	0.11	0.14	0.24	0.28	0.50	0.62	0.82	0.61	0.74	0.81	0.85	0.86	0.85	0.74	0.71	0.66	0.62	0.57	0.39	0.16	0.06	0.02
Onsite Off-Road + Onsite Vehicle	53.20	75.65	56.09	113.55	114.64	109.16	78.92	91.27	90.86	90.93	89.47	92.39	98.96	102.80	77.27	74.31	74.27	50.73	41.12	29.25	33.60	29.11
Offsite Haul Truck	4.64	4.68	9.22	5.84	18.70	25.71	46.42	16.10	16.97	8.66	4.61	4.17	4.36	4.39	4.33	4.39	8.39	7.72	8.79	3.87	0.00	0.00
Offsite Delivery Truck	0.00	1.76	1.76	1.76	7.05	10.57	10.57	9.56	12.74	15.93	12.74	9.56	3.19	1.59	1.59	1.59	1.59	1.59	1.59	0.00	0.00	0.00
Offsite Worker Travel	11.68	14.38	23.81	34.14	46.72	52.12	58.41	63.07	78.64	95.40	110.57	116.56	121.75	106.98	102.19	94.20	83.03	76.64	48.30	19.65	8.93	3.57
	SO2 (lbs/day)																					
Onsite Off-Road Equipment	0.10	0.14	0.11	0.22	0.22	0.21	0.16	0.18	0.18	0.18	0.18	0.18	0.19	0.20	0.15	0.15	0.15	0.10	0.08	0.06	0.06	0.05
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.10	0.14	0.11	0.22	0.22	0.21	0.16	0.18	0.18	0.18	0.18	0.18	0.20	0.20	0.15	0.15	0.15	0.10	0.08	0.06	0.06	0.05
Offsite Haul Truck	2.46E-02	2.47E-02	4.88E-02	1.61E-02	9.90E-02	1.36E-01	2.46E-01	9.05E-02	9.54E-02	4.87E-02	2.59E-02	2.34E-02	2.45E-02	2.47E-02	2.43E-02	2.47E-02	4.71E-02	4.34E-02	4.94E-02	2.25E-02	0.00E+00	0.00E+00
Offsite Delivery Truck	0.00E+00	8.28E-03	8.28E-03	8.28E-03	3.31E-02	4.97E-02	4.97E-02	4.96E-02	6.62E-02	8.27E-02	6.62E-02	4.96E-02	1.65E-02	8.27E-03	8.27E-03	8.27E-03	8.27E-03	8.27E-03	8.27E-03	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	1.96E-02	2.41E-02	3.99E-02	5.72E-02	7.83E-02	8.73E-02	9.79E-02	1.19E-01	1.48E-01	1.80E-01	2.08E-01	2.20E-01	2.29E-01	2.02E-01	1.93E-01	1.78E-01	1.57E-01	1.44E-01	9.10E-02	4.13E-02	1.88E-02	7.52E-03
	PM10 (lbs/day)																					
Onsite Off-Road Equipment	0.22	0.29	0.22	0.39	0.43	0.38	0.23	0.28	0.27	0.27	0.27	0.28	0.30	0.30	0.23	0.22	0.22	0.15	0.13	0.09	0.10	0.09
Onsite Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.22	0.29	0.23	0.40	0.44	0.40	0.25	0.28	0.28	0.28	0.28	0.29	0.30	0.31	0.24	0.23	0.23	0.16	0.13	0.09	0.10	0.09
Offsite Haul Truck	0.21	0.21	0.41	0.13	0.84	1.16	2.09	0.69	0.72	0.37	0.20	0.18	0.19	0.19	0.18	0.19	0.36	0.33	0.37	0.17	0.00	0.00
Offsite Delivery Truck	0.00E+00	8.28E-02	8.28E-02	8.28E-02	3.31E-01	4.97E-01	4.97E-01	4.38E-01	5.84E-01	7.30E-01	5.84E-01	4.38E-01	1.46E-01	7.30E-02	7.30E-02	7.30E-02	7.30E-02	7.30E-02	7.30E-02	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	9.83E-03	1.21E-02	2.00E-02	2.87E-02	3.93E-02	4.38E-02	4.91E-02	5.71E-02	7.12E-02	8.64E-02	1.00E-01	1.06E-01	1.10E-01	9.69E-02	9.25E-02	8.53E-02	7.52E-02	6.94E-02	4.37E-02	1.93E-02	8.76E-03	3.51E-03
Onsite Fugitive (Off-Road)	0.78	0.78	0.78	1.03	0.78	0.78	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive (Vehicle)	1.35	1.69	2.81	3.79	5.71	6.67	8.29	8.09	10.01	11.58	12.91	13.33	13.61	11.92	11.40	10.54	9.52	8.78	5.77	2.59	1.08	0.43
Onsite Fugitive - Off-Road + Onsite Veh	2.12	2.46	3.59	4.83	6.48	7.45	8.55	8.09	10.01	11.58	12.91	13.33	13.61	11.92	11.40	10.54	9.52	8.78	5.77	2.59	1.08	0.43
Offsite Fugitive - Haul Truck	0.58	0.58	1.15	0.37	2.33	3.21	5.79	2.14	2.25	1.15	0.61	0.55	0.58	0.58	0.57	0.58	1.11	1.02	1.17	0.53	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.25	0.25	0.25	1.01	1.51	1.51	1.51	2.01	2.52	2.01	1.51	0.50	0.25	0.25	0.25	0.25	0.25	0.25	0.00	0.00	0.00
Offsite Fugitive - Worker Travel	1.49	1.84	3.04	4.37	5.97	6.66	7.47	9.08	11.32	13.73	15.91	16.77	17.52	15.39	14.70	13.56	11.95	11.03	6.95	3.16	1.44	0.57
	PM2.5 (lbs/day)																					
Onsite Off-Road Equipment	0.22	0.29	0.22	0.39	0.43	0.38	0.23	0.28	0.27	0.27	0.27	0.28	0.30	0.30	0.23	0.22	0.22	0.15	0.13	0.09	0.10	0.09
Onsite Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.22	0.29	0.23	0.40	0.44	0.40	0.25	0.28	0.28	0.28	0.28	0.28	0.30	0.31	0.24	0.23	0.23	0.16	0.13	0.09	0.10	0.09
Offsite Haul Truck	0.19	0.19	0.38	0.12	0.77	1.06	1.92	0.63	0.66	0.34	0.18	0.16	0.17	0.17	0.17	0.17	0.33	0.30	0.34	0.15	0.00	0.00
Offsite Delivery Truck	0.00E+00	7.62E-02	7.62E-02	7.62E-02	3.05E-01	4.57E-01	4.57E-01	4.03E-01	5.37E-01	6.72E-01	5.37E-01	4.03E-01	1.34E-01	6.72E-02	6.72E-02	6.72E-02	6.72E-02	6.72E-02	6.72E-02	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	8.99E-03	1.11E-02	1.83E-02	2.63E-02	3.60E-02	4.01E-02	4.49E-02	5.25E-02	6.55E-02	7.94E-02	9.21E-02	9.71E-02	1.01E-01	8.91E-02	8.51E-02	7.84E-02	6.91E-02	6.38E-02	4.02E-02	1.78E-02	8.10E-03	3.24E-03
Onsite Fugitive (Off-Road)	0.08	0.08	0.08	0.11	0.08	0.08	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive (Vehicle)	0.13	0.17	0.28	0.38	0.57	0.67	0.83	0.81	1.00	1.16	1.29	1.33	1.36	1.19	1.14	1.05	0.95	0.88	0.58	0.26	0.11	0.04
Onsite Fugitive - Off-Road + Onsite Veh	0.22	0.25	0.36	0.49	0.65	0.75	0.86	0.81	1.00	1.16	1.29	1.33	1.36	1.19	1.14	1.05	0.95	0.88	0.58	0.26	0.11	0.04
Offsite Fugitive - Haul Truck	0.16	0.16	0.32	0.10	0.64	0.89	1.60	0.59	0.62	0.32	0.17	0.15	0.16	0.16	0.16	0.16	0.31	0.28	0.32	0.15	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.07	0.07	0.07	0.29	0.43	0.43	0.43	0.58	0.72	0.58	0.43	0.14	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Offsite Fugitive - Worker Travel	0.40	0.49	0.81	1.16	1.59	1.78	1.99	2.42	3.02	3.66	4.24	4.47	4.67	4.11	3.92	3.62	3.19	2.94	1.85	0.84	0.38	0.15

Construction of the Proposed SEP Project Site - Summer (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	CO2 (lbs/day)																					
Onsite Off-Road Equipment	10,449	14,805	10,827	21,951	22,062	21,327	15,549	17,885	17,789	17,789	17,556	18,117	19,376	19,831	15,252	14,691	14,691	9,789	8,054	5,723	6,314	5,498
Onsite Vehicle	29.49	38.43	65.51	49.41	144.05	190.34	280.79	167.78	199.17	192.39	177.19	168.55	149.27	128.81	123.91	116.43	122.69	113.63	90.73	37.35	9.31	3.72
Onsite Off-Road + Onsite Vehicle	10,478	14,843	10,892	22,000	22,206	21,517	15,829	18,053	17,988	17,981	17,733	18,285	19,525	19,959	15,376	14,808	14,814	9,903	8,145	5,760	6,323	5,502
Offsite Haul Truck	2,479	2,497	4,925	1,617	9,989	13,731	24,792	8,994	9,481	4,839	2,576	2,330	2,436	2,454	2,419	2,454	4,684	4,309	4,907	2,201	0	0
Offsite Delivery Truck	0	833	833	833	3,332	4,997	4,997	4,915	6,553	8,191	6,553	4,915	1,638	819	819	819	819	819	819	0	0	0
Offsite Worker Travel	1,609	1,980	3,280	4,703	6,436	7,178	8,045	9,388	11,705	14,200	16,458	17,349	18,121	15,923	15,210	14,022	12,358	11,408	7,189	3,143	1,429	571
	CH4 (lbs/day)																					
Onsite Off-Road Equipment	3.11	4.42	3.21	5.80	5.84	5.60	3.84	4.60	4.57	4.57	4.51	4.68	5.06	4.89	3.80	3.63	3.63	2.93	2.42	1.73	1.92	1.71
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	3.11	4.42	3.22	5.80	5.84	5.61	3.84	4.60	4.58	4.58	4.51	4.68	5.07	4.90	3.81	3.63	3.63	2.94	2.42	1.74	1.92	1.71
Offsite Haul Truck	1.24E-02	1.25E-02	2.46E-02	8.73E-03	4.98E-02	6.85E-02	1.24E-01	4.27E-02	4.50E-02	2.30E-02	1.22E-02	1.11E-02	1.16E-02	1.17E-02	1.15E-02	1.17E-02	2.22E-02	2.05E-02	2.33E-02	1.05E-02	0.00E+00	0.00E+00
Offsite Delivery Truck	0.00E+00	4.11E-03	4.11E-03	4.11E-03	1.65E-02	2.47E-02	2.47E-02	2.26E-02	3.01E-02	3.76E-02	3.01E-02	2.26E-02	7.53E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	0.09	0.11	0.18	0.26	0.36	0.40	0.44	0.49	0.62	0.75	0.87	0.91	0.96	0.84	0.80	0.74	0.65	0.60	0.38	0.16	0.07	0.03
	N2O (lbs/day)																					
Onsite Off-Road Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Haul Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Delivery Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Worker Travel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CO2e (lbs/day)																					
Onsite Off-Road Equipment	10,526	14,915	10,907	22,096	22,208	21,467	15,645	18,000	17,903	17,903	17,669	18,234	19,502	19,953	15,347	14,782	14,782	9,862	8,115	5,766	6,362	5,541
Onsite Vehicle	29.50	38.45	65.54	49.46	144.12	190.42	280.89	167.87	199.28	192.53	177.34	168.71	149.43	128.95	124.04	116.55	122.80	113.73	90.80	37.38	9.32	3.73
Onsite Off-Road + Onsite Vehicle	10,556	14,954	10,973	22,145	22,352	21,657	15,925	18,168	18,102	18,095	17,846	18,402	19,652	20,082	15,471	14,898	14,905	9,976	8,206	5,803	6,371	5,545
Offsite Haul Truck	2,479	2,498	4,926	1,617	9,991	13,733	24,795	8,995	9,482	4,840	2,577	2,330	2,436	2,454	2,420	2,454	4,685	4,310	4,908	2,201	0	0
Offsite Delivery Truck	0	833	833	833	3,332	4,998	4,998	4,915	6,553	8,192	6,553	4,915	1,638	819	819	819	819	819	819	0	0	0
Offsite Worker Travel	1,611	1,983	3,284	4,710	6,445	7,188	8,056	9,400	11,720	14,219	16,480	17,372	18,145	15,944	15,230	14,040	12,375	11,423	7,199	3,147	1,431	572

Construction of the Proposed SEP Transmission Line - Summer (Peak) Daily Emissions

Project Month	7	8	9	10	11	12	13
				ROG (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.87	0.66	4.21	8.89	5.16	0.74
T-Line Site Vehicle	0.00	0.00	0.01	0.01	0.01	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.87	0.66	4.22	8.90	5.16	0.74
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	0.40	0.35	0.37	0.00	0.00
Offsite Worker Travel	0.02	0.30	0.43	0.43	0.43	0.21	0.16
				NOx (lbs/day)			
T-Line Site Off-Road Equipment	0.00	13.98	11.36	71.09	150.99	87.58	11.98
T-Line Site Vehicle	0.00	0.00	0.06	0.05	0.05	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	13.98	11.42	71.14	151.04	87.58	11.98
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	6.74	5.84	6.29	0.00	0.00
Offsite Worker Travel	0.04	0.69	1.00	1.00	1.00	0.48	0.38
				CO (lbs/day)			
T-Line Site Off-Road Equipment	0.00	28.17	22.30	139.95	298.08	173.60	24.14
T-Line Site Vehicle	0.00	0.05	0.11	0.11	0.11	0.04	0.03
T-Line Site Off-Road + T-Line Site Vehicle	0.00	28.22	22.41	140.06	298.19	173.64	24.17
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	4.78	4.14	4.46	0.00	0.00
Offsite Worker Travel	0.45	7.98	11.58	11.58	11.58	5.59	4.39
				SO2 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.05	0.04	0.25	0.54	0.32	0.05
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.05	0.04	0.25	0.54	0.32	0.05
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	2.48E-02	2.15E-02	2.32E-02	0.00E+00	0.00E+00
Offsite Worker Travel	7.50E-04	1.50E-02	2.18E-02	2.18E-02	2.18E-02	1.05E-02	8.27E-03
				PM10 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.09	0.07	0.42	0.89	0.52	0.07
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.09	0.07	0.42	0.89	0.52	0.07
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	2.19E-01	1.90E-01	2.04E-01	0.00E+00	0.00E+00
Offsite Worker Travel	3.80E-04	7.23E-03	1.05E-02	1.05E-02	1.05E-02	5.06E-03	3.98E-03
T-Line Site Fugitive (Off-Road)	0.00	0.26	0.00	0.00	2.94	2.94	0.26
T-Line Site Fugitive (T-Line Site Vehicle)	0.01	0.14	0.34	0.32	0.34	0.10	0.08
T-Line Site Fugitive - Off-Road + T-Line Site Veh	0.01	0.40	0.34	0.32	3.27	3.04	0.34
Offsite Fugitive - Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.00	0.75	0.65	0.70	0.00	0.00
Offsite Fugitive - Worker Travel	0.06	1.15	1.67	1.67	1.67	0.80	0.63
				PM2.5 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.09	0.07	0.42	0.89	0.52	0.07
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.09	0.07	0.42	0.89	0.52	0.07
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	2.02E-01	1.75E-01	1.88E-01	0.00E+00	0.00E+00
Offsite Worker Travel	3.50E-04	6.65E-03	9.64E-03	9.64E-03	9.64E-03	4.65E-03	3.66E-03
T-Line Site Fugitive (Off-Road)	0.00	0.03	0.00	0.00	1.61	1.61	0.03
T-Line Site Fugitive (T-Line Site Vehicle)	0.00	0.01	0.03	0.03	0.03	0.01	0.01
T-Line Site Fugitive - Off-Road + T-Line Site Veh	0.00	0.04	0.03	0.03	1.65	1.62	0.04
Offsite Fugitive - Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.00	0.22	0.19	0.20	0.00	0.00
Offsite Fugitive - Worker Travel	0.02	0.31	0.44	0.44	0.44	0.21	0.17

Construction of the Proposed SEP Transmission Line - Summer (Peak) Daily Emissions

Project Month	7	8	9	10	11	12	13
				CO2 (lbs/day)			
T-Line Site Off-Road Equipment	0	5,401	4,056	26,035	55,458	32,373	4,632
T-Line Site Vehicle	0.40	7.74	30.19	27.67	28.93	5.48	4.30
T-Line Site Off-Road + T-Line Site Vehicle	0	5,408	4,086	26,063	55,487	32,379	4,636
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0	0	2,457	2,130	2,293	0	0
Offsite Worker Travel	62	1,188	1,723	1,723	1,723	832	654
				CH4 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	1.65	1.24	7.98	16.99	9.92	1.42
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	1.66	1.24	7.98	16.99	9.92	1.42
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	1.13E-02	9.78E-03	1.05E-02	0.00E+00	0.00E+00
Offsite Worker Travel	0.00	0.06	0.09	0.09	0.09	0.04	0.03
				N2O (lbs/day)			
T-Line Site Off-Road Equipment	0		0	0	0	0	0
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0	0	0	0	0	0	0
Offsite Haul Truck	0		0	0	0	0	0
Offsite Delivery Truck	0		0	0	0	0	0
Offsite Worker Travel	0		0	0	0	0	0
				CO2e (lbs/day)			
T-Line Site Off-Road Equipment	0	5,442	4,087	26,235	55,883	32,621	4,668
T-Line Site Vehicle	0.40	7.75	30.20	27.69	28.95	5.48	4.31
T-Line Site Off-Road + T-Line Site Vehicle	0	5,450	4,118	26,262	55,912	32,627	4,672
Offsite Haul Truck	0	0	0	0	0	0	0
Offsite Delivery Truck	0	0	2,458	2,130	2,294	0	0
Offsite Worker Travel	62	1,190	1,725	1,725	1,725	833	654

Construction of the Proposed SEP Project Site - Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	ROG (lbs/day)																					
Onsite Off-Road Equipment	1.64	2.32	1.72	3.42	3.45	3.34	2.40	2.79	2.77	2.77	2.73	2.82	3.02	3.03	2.36	2.27	2.27	1.55	1.25	0.90	0.97	0.90
Onsite Vehicle	0.01	0.01	0.01	0.01	0.03	0.04	0.05	0.03	0.04	0.04	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00
Onsite Off-Road + Onsite Vehicle	1.64	2.33	1.74	3.43	3.48	3.38	2.45	2.82	2.81	2.81	2.76	2.85	3.05	3.05	2.38	2.29	2.29	1.57	1.27	0.90	0.97	0.90
Offsite Haul Truck	0.43	0.44	0.86	0.50	1.75	2.40	4.34	1.46	1.54	0.79	0.42	0.38	0.40	0.40	0.39	0.40	0.76	0.70	0.80	0.35	0.00	0.00
Offsite Delivery Truck	0.00	0.15	0.15	0.15	0.61	0.92	0.92	0.83	1.10	1.38	1.10	0.83	0.28	0.14	0.14	0.14	0.14	0.14	0.14	0.00	0.00	0.00
Offsite Worker Travel	0.38	0.47	0.77	1.11	1.52	1.69	1.90	1.93	2.41	2.92	3.39	3.57	3.73	3.28	3.13	2.89	2.54	2.35	1.48	0.56	0.26	0.10
	NOx (lbs/day)																					
Onsite Off-Road Equipment	26.84	38.23	28.92	58.01	58.86	55.29	39.84	45.72	45.45	45.45	44.44	45.89	49.15	51.80	38.47	37.02	37.02	25.37	20.21	14.43	17.02	14.43
Onsite Vehicle	0.06	0.08	0.14	0.08	0.33	0.46	0.71	0.32	0.38	0.33	0.26	0.22	0.16	0.13	0.13	0.12	0.16	0.15	0.14	0.05	0.01	0.00
Onsite Off-Road + Onsite Vehicle	26.90	38.31	29.06	58.09	59.19	55.75	40.55	46.05	45.83	45.79	44.71	46.11	49.31	51.93	38.59	37.14	37.18	25.51	20.35	14.48	17.03	14.44
Offsite Haul Truck	7.13	7.18	14.16	4.93	28.72	39.48	71.28	22.87	24.11	12.31	6.55	5.93	6.19	6.24	6.15	6.24	11.91	10.96	12.48	5.06	0.00	0.00
Offsite Delivery Truck	0.00	2.74	2.74	2.74	10.94	16.42	16.42	14.31	19.08	23.86	19.08	14.31	4.77	2.39	2.39	2.39	2.39	2.39	2.39	0.00	0.00	0.00
Offsite Worker Travel	1.05	1.29	2.14	3.07	4.20	4.68	5.25	5.70	7.11	8.63	10.00	10.54	11.01	9.67	9.24	8.52	7.51	6.93	4.37	1.79	0.81	0.33
	CO (lbs/day)																					
Onsite Off-Road Equipment	53.09	75.51	55.85	113.27	114.14	108.54	78.11	90.66	90.12	90.12	88.61	91.52	98.11	102.06	76.56	73.65	73.65	50.16	40.73	29.09	33.54	29.09
Onsite Vehicle	0.10	0.13	0.21	0.24	0.45	0.57	0.77	0.53	0.65	0.69	0.70	0.70	0.68	0.59	0.57	0.53	0.50	0.47	0.33	0.13	0.04	0.02
Onsite Off-Road + Onsite Vehicle	53.19	75.64	56.06	113.50	114.59	109.11	78.88	91.20	90.76	90.80	89.32	92.23	98.78	102.65	77.13	74.18	74.16	50.63	41.06	29.22	33.59	29.11
Offsite Haul Truck	5.09	5.13	10.12	6.73	20.52	28.21	50.93	17.80	18.77	9.58	5.10	4.61	4.82	4.86	4.79	4.86	9.27	8.53	9.71	4.29	0.00	0.00
Offsite Delivery Truck	0.00	1.87	1.87	1.87	7.48	11.21	11.21	10.23	13.65	17.06	13.65	10.23	3.41	1.71	1.71	1.71	1.71	1.71	1.71	0.00	0.00	0.00
Offsite Worker Travel	9.09	11.19	18.54	26.58	36.37	40.57	45.46	48.89	60.96	73.96	85.72	90.36	94.38	82.93	79.22	73.03	64.37	59.41	37.44	15.17	6.89	2.76
	SO2 (lbs/day)																					
Onsite Off-Road Equipment	0.10	0.14	0.11	0.22	0.22	0.21	0.16	0.18	0.18	0.18	0.18	0.18	0.19	0.20	0.15	0.15	0.15	0.10	0.08	0.06	0.06	0.05
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.10	0.14	0.11	0.22	0.22	0.21	0.16	0.18	0.18	0.18	0.18	0.18	0.20	0.20	0.15	0.15	0.15	0.10	0.08	0.06	0.06	0.05
Offsite Haul Truck	0.02	0.02	0.05	0.02	0.10	0.14	0.25	0.09	0.10	0.05	0.03	0.02	0.02	0.02	0.02	0.02	0.05	0.04	0.05	0.02	0.00	0.00
Offsite Delivery Truck	0.00	0.01	0.01	0.01	0.03	0.05	0.05	0.05	0.07	0.08	0.07	0.05	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Offsite Worker Travel	0.02	0.02	0.04	0.05	0.07	0.08	0.09	0.11	0.13	0.16	0.19	0.20	0.21	0.18	0.17	0.16	0.14	0.13	0.08	0.04	0.02	0.01
	PM10 (lbs/day)																					
Onsite Off-Road Equipment	0.22	0.29	0.22	0.39	0.43	0.38	0.23	0.28	0.27	0.27	0.27	0.28	0.30	0.30	0.23	0.22	0.22	0.15	0.13	0.09	0.10	0.09
Onsite Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.22	0.29	0.23	0.40	0.44	0.40	0.25	0.28	0.28	0.28	0.28	0.29	0.30	0.31	0.24	0.23	0.23	0.16	0.13	0.09	0.10	0.09
Offsite Haul Truck	0.21	0.21	0.41	0.14	0.84	1.16	2.09	0.69	0.72	0.37	0.20	0.18	0.19	0.19	0.18	0.19	0.36	0.33	0.37	0.17	0.00	0.00
Offsite Delivery Truck	0.00	0.08	0.08	0.08	0.33	0.50	0.50	0.44	0.58	0.73	0.58	0.44	0.15	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Offsite Worker Travel	0.01	0.01	0.02	0.03	0.04	0.04	0.05	0.06	0.07	0.09	0.10	0.11	0.11	0.10	0.09	0.09	0.08	0.07	0.04	0.02	0.01	0.00
Onsite Fugitive (Off-Road)	0.78	0.78	0.78	1.03	0.78	0.78	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive (Vehicle)	1.35	1.69	2.81	3.79	5.71	6.67	8.29	8.09	10.01	11.58	12.91	13.33	13.61	11.92	11.40	10.54	9.52	8.78	5.77	2.59	1.08	0.43
Onsite Fugitive - Off-Road + Onsite Veh	2.12	2.46	3.59	4.83	6.48	7.45	8.55	8.09	10.01	11.58	12.91	13.33	13.61	11.92	11.40	10.54	9.52	8.78	5.77	2.59	1.08	0.43
Offsite Fugitive - Haul Truck	0.58	0.58	1.15	0.37	2.33	3.21	5.79	2.14	2.25	1.15	0.61	0.55	0.58	0.58	0.57	0.58	1.11	1.02	1.17	0.53	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.25	0.25	0.25	1.01	1.51	1.51	1.51	2.01	2.52	2.01	1.51	0.50	0.25	0.25	0.25	0.25	0.25	0.25	0.00	0.00	0.00
Offsite Fugitive - Worker Travel	1.49	1.84	3.04	4.37	5.97	6.66	7.47	9.08	11.32	13.73	15.91	16.77	17.52	15.39	14.70	13.56	11.95	11.03	6.95	3.16	1.44	0.57

Construction of the Proposed SEP Project Site - Winter (Peak) Daily Emissions

Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
	PM2.5 (lbs/day)																					
Onsite Off-Road Equipment	0.22	0.29	0.22	0.39	0.43	0.38	0.23	0.28	0.27	0.27	0.27	0.28	0.30	0.30	0.23	0.22	0.22	0.15	0.13	0.09	0.10	0.09
Onsite Vehicle	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0.22	0.29	0.23	0.40	0.44	0.40	0.25	0.28	0.28	0.28	0.28	0.28	0.30	0.31	0.24	0.23	0.23	0.16	0.13	0.09	0.10	0.09
Offsite Haul Truck	0.19	0.19	0.38	0.12	0.77	1.06	1.92	0.63	0.66	0.34	0.18	0.16	0.17	0.17	0.17	0.17	0.33	0.30	0.34	0.15	0.00	0.00
Offsite Delivery Truck	0.00	0.08	0.08	0.08	0.30	0.46	0.46	0.40	0.54	0.67	0.54	0.40	0.13	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Offsite Worker Travel	0.01	0.01	0.02	0.03	0.04	0.04	0.04	0.05	0.07	0.08	0.09	0.10	0.10	0.09	0.09	0.08	0.07	0.06	0.04	0.02	0.01	0.00
Onsite Fugitive (Off-Road)	0.08	0.08	0.08	0.11	0.08	0.08	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive (Vehicle)	0.13	0.17	0.28	0.38	0.57	0.67	0.83	0.81	1.00	1.16	1.29	1.33	1.36	1.19	1.14	1.05	0.95	0.88	0.58	0.26	0.11	0.04
Onsite Fugitive - Off-Road + Onsite Veh	0.22	0.25	0.36	0.49	0.65	0.75	0.86	0.81	1.00	1.16	1.29	1.33	1.36	1.19	1.14	1.05	0.95	0.88	0.58	0.26	0.11	0.04
Offsite Fugitive - Haul Truck	0.16	0.16	0.32	0.10	0.64	0.89	1.60	0.59	0.62	0.32	0.17	0.15	0.16	0.16	0.16	0.16	0.31	0.28	0.32	0.15	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.07	0.07	0.07	0.29	0.43	0.43	0.43	0.58	0.72	0.58	0.43	0.14	0.07	0.07	0.07	0.07	0.07	0.07	0.00	0.00	0.00
Offsite Fugitive - Worker Travel	0.40	0.49	0.81	1.16	1.59	1.78	1.99	2.42	3.02	3.66	4.24	4.47	4.67	4.11	3.92	3.62	3.19	2.94	1.85	0.84	0.38	0.15
	CO2 (lbs/day)																					
Onsite Off-Road Equipment	10,449	14,805	10,827	21,951	22,062	21,327	15,549	17,885	17,789	17,789	17,556	18,117	19,376	19,831	15,252	14,691	14,691	9,789	8,054	5,723	6,314	5,498
Onsite Vehicle	28.39	37.08	63.27	46.22	139.64	185.40	275.19	161.39	191.21	182.78	166.09	156.87	137.10	118.12	113.69	107.01	114.37	105.95	85.88	35.23	8.35	3.34
Onsite Off-Road + Onsite Vehicle	10477	14842	10,890	21,997	22,201	21,512	15,824	18,047	17,980	17,971	17,722	18,274	19,513	19,949	15,365	14,798	14,805	9,895	8,140	5,758	6,322	5,501
Offsite Haul Truck	2477	2495	4921	1613	9981	13719	24771	8986	9473	4835	2574	2328	2434	2452	2417	2452	4680	4306	4903	2199	0	0
Offsite Delivery Truck	0	832	832	832	3328	4992	4992	4909	6546	8182	6546	4909	1636	818	818	818	818	818	818	0	0	0
Offsite Worker Travel	1,443	1,776	2,942	4,219	5,773	6,439	7,217	8,422	10,501	12,739	14,765	15,564	16,257	14,285	13,646	12,579	11,087	10,234	6,450	2,820	1,282	513
	CH4 (lbs/day)																					
Onsite Off-Road Equipment	3.11	4.42	3.21	5.80	5.84	5.60	3.84	4.60	4.57	4.57	4.51	4.68	5.06	4.89	3.80	3.63	3.63	2.93	2.42	1.73	1.92	1.71
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	3.11	4.42	3.22	5.80	5.84	5.61	3.84	4.60	4.58	4.58	4.51	4.68	5.07	4.90	3.81	3.63	3.63	2.94	2.42	1.74	1.92	1.71
Offsite Haul Truck	1.25E-02	1.25E-02	2.47E-02	8.90E-03	5.02E-02	6.90E-02	1.25E-01	4.30E-02	4.54E-02	2.32E-02	1.23E-02	1.12E-02	1.17E-02	1.17E-02	1.16E-02	1.17E-02	2.24E-02	2.06E-02	2.35E-02	1.05E-02	0.00E+00	0.00E+00
Offsite Delivery Truck	0.00E+00	4.14E-03	4.14E-03	4.14E-03	1.66E-02	2.48E-02	2.48E-02	2.27E-02	3.03E-02	3.79E-02	3.03E-02	2.27E-02	7.58E-03	3.79E-03	3.79E-03	3.79E-03	3.79E-03	3.79E-03	3.79E-03	0.00E+00	0.00E+00	0.00E+00
Offsite Worker Travel	0.09	0.11	0.18	0.26	0.36	0.40	0.44	0.49	0.62	0.75	0.87	0.91	0.96	0.84	0.80	0.74	0.65	0.60	0.38	0.16	0.07	0.03
	N2O (lbs/day)																					
Onsite Off-Road Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Haul Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Delivery Truck	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Offsite Worker Travel	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	CO2e (lbs/day)																					
Onsite Off-Road Equipment	10,526	14,915	10,907	22,096	22,208	21,467	15,645	18,000	17,903	17,903	17,669	18,234	19,502	19,953	15,347	14,782	14,782	9,862	8,115	5,766	6,362	5,541
Onsite Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Off-Road + Onsite Vehicle	10,526	14,915	10,907	22,096	22,208	21,467	15,645	18,000	17,903	17,903	17,669	18,234	19,502	19,953	15,347	14,782	14,782	9,862	8,115	5,766	6,362	5,541
Offsite Haul Truck	2,477	2,496	4,922	1,613	9,982	13,721	24,774	8,987	9,474	4,835	2,574	2,328	2,434	2,452	2,418	2,452	4,681	4,306	4,904	2,200	0	0
Offsite Delivery Truck	0	832	832	832	3,328	4,992	4,992	4,910	6,546	8,183	6,546	4,910	1,637	818	818	818	818	818	818	0	0	0
Offsite Worker Travel	1,446	1,779	2,947	4,225	5,782	6,449	7,228	8,434	10,516	12,758	14,787	15,587	16,281	14,306	13,666	12,598	11,103	10,249	6,459	2,824	1,284	513

Construction of the Proposed SEP Transmission Line - Winter (Peak) Daily Emissions

Project Month	7	8	9	10	11	12	13
				ROG (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.87	0.66	4.21	8.89	5.16	0.74
T-Line Site Vehicle	0.00	0.00	0.01	0.01	0.01	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.87	0.66	4.22	8.90	5.16	0.74
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	0.41	0.36	0.39	0.00	0.00
Offsite Worker Travel	0.01	0.24	0.35	0.35	0.35	0.17	0.13
				NOx (lbs/day)			
T-Line Site Off-Road Equipment	0.00	13.98	11.36	71.09	150.99	87.58	11.98
T-Line Site Vehicle	0.00	0.00	0.06	0.05	0.06	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	13.98	11.42	71.14	151.04	87.58	11.98
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	7.16	6.20	6.68	0.00	0.00
Offsite Worker Travel	0.04	0.72	1.05	1.05	1.05	0.51	0.40
				CO (lbs/day)			
T-Line Site Off-Road Equipment	0.00	28.17	22.30	139.95	298.08	173.60	24.14
T-Line Site Vehicle	0.00	0.04	0.10	0.09	0.10	0.03	0.02
T-Line Site Off-Road + T-Line Site Vehicle	0.00	28.21	22.40	140.04	298.17	173.63	24.16
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	5.12	4.43	4.78	0.00	0.00
Offsite Worker Travel	0.35	6.19	8.97	8.97	8.97	4.33	3.40
				SO2 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.05	0.04	0.25	0.54	0.32	0.05
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.05	0.04	0.25	0.54	0.32	0.05
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	2.48E-02	2.15E-02	2.31E-02	0.00E+00	0.00E+00
Offsite Worker Travel	6.70E-04	1.35E-02	1.95E-02	1.95E-02	1.95E-02	9.43E-03	7.41E-03
				PM10 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.09	0.07	0.42	0.89	0.52	0.07
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.09	0.07	0.42	0.89	0.52	0.07
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00	0.00	0.22	0.19	0.20	0.00	0.00
Offsite Worker Travel	3.80E-04	7.23E-03	1.05E-02	1.05E-02	1.05E-02	5.06E-03	3.98E-03
T-Line Site Fugitive (Off-Road)	0.00	0.26	0.00	0.00	2.94	2.94	0.26
T-Line Site Fugitive (T-Line Site Vehicle)	0.01	0.14	0.34	0.32	0.34	0.10	0.08
T-Line Site Fugitive - Off-Road + T-Line Site Veh	0.01	0.40	0.34	0.32	3.27	3.04	0.34
Offsite Fugitive - Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.00	0.75	0.65	0.70	0.00	0.00
Offsite Fugitive - Worker Travel	0.06	1.15	1.67	1.67	1.67	0.80	0.63
				PM2.5 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	0.09	0.07	0.42	0.89	0.52	0.07
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	0.09	0.07	0.42	0.89	0.52	0.07
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	2.02E-01	1.75E-01	1.88E-01	0.00E+00	0.00E+00
Offsite Worker Travel	3.50E-04	6.65E-03	9.64E-03	9.64E-03	9.64E-03	4.65E-03	3.66E-03
T-Line Site Fugitive (Off-Road)	0.00	0.03	0.00	0.00	1.61	1.61	0.03
T-Line Site Fugitive (T-Line Site Vehicle)	0.00	0.01	0.03	0.03	0.03	0.01	0.01
T-Line Site Fugitive - Off-Road + T-Line Site Veh	0.00	0.04	0.03	0.03	1.65	1.62	0.04
Offsite Fugitive - Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Fugitive - Delivery Truck	0.00	0.00	0.22	0.19	0.20	0.00	0.00
Offsite Fugitive - Worker Travel	0.02	0.31	0.44	0.44	0.44	0.21	0.17

Construction of the Proposed SEP Transmission Line - Winter (Peak) Daily Emissions

Project Month	7	8	9	10	11	12	13
				CO2 (lbs/day)			
T-Line Site Off-Road Equipment	0	5,401	4,056	26,035	55,458	32,373	4,632
T-Line Site Vehicle	0.36	6.94	29.00	26.49	27.74	4.91	3.86
T-Line Site Off-Road + T-Line Site Vehicle	0	5408	4085	26,062	55,486	32,378	4,636
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0	0	2455	2127	2291	0	0
Offsite Worker Travel	56	1,066	1,546	1,546	1,546	746	586
				CH4 (lbs/day)			
T-Line Site Off-Road Equipment	0.00	1.65	1.24	7.98	16.99	9.92	1.42
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0.00	1.66	1.24	7.98	16.99	9.92	1.42
Offsite Haul Truck	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Offsite Delivery Truck	0.00E+00	0.00E+00	1.14E-02	9.85E-03	1.06E-02	0.00E+00	0.00E+00
Offsite Worker Travel	0.00	0.06	0.09	0.09	0.09	0.04	0.03
				N2O (lbs/day)			
T-Line Site Off-Road Equipment	0	0	0	0	0	0	0
T-Line Site Vehicle	0.00	0.00	0.00	0.00	0.00	0.00	0.00
T-Line Site Off-Road + T-Line Site Vehicle	0	0	0	0	0	0	0
Offsite Haul Truck	0	0	0	0	0	0	0
Offsite Delivery Truck	0	0	0	0	0	0	0
Offsite Worker Travel	0	0	0	0	0	0	0
				CO2e (lbs/day)			
T-Line Site Off-Road Equipment	0	5,442	4,087	26,235	55,883	32,621	4,668
T-Line Site Vehicle	0.36	6.95	29.02	26.51	27.76	4.92	3.87
T-Line Site Off-Road + T-Line Site Vehicle	0	5,449	4,116	26,261	55,911	32,626	4,672
Offsite Haul Truck	0	0	0	0	0	0	0
Offsite Delivery Truck	0	0	2,455	2,128	2,291	0	0
Offsite Worker Travel	56	1,068	1,548	1,548	1,548	747	587

Fugitive Dust Calculations

Worker, Delivery (vendor) Trucks and Haul Trucks Onsite Travels

Onsite travel for worker, truck delivery, and haul trucks are assumed to be on graveled surfaces.

- Onsite delivery and haul truck travel distances are estimated from the site security point to the laydown area, 0.46 mile (one-way)
- Onsite work travel distance is estimated from the site security point to the parking area 0.27 mile (one-way)

Total Controlled Fugitive Emissions for Worker, Delivery Trucks and Haul Truck travel for Project Construction

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of Workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22
Onsite Fugitive PM10 (ton/month)	0.01	0.02	0.03	0.04	0.06	0.07	0.09	0.08	0.09	0.13	0.12	0.15	0.15	0.12	0.13	0.11	0.10	0.10	0.06	0.03	0.01	0.00
Onsite Fugitive PM2.5 (ton/month)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Onsite Fugitive PM10, Rolling 12-month total (tons/year)												0.89	1.03	1.13	1.23	1.30	1.35	1.38	1.35	1.29	1.21	1.09
Onsite Fugitive PM2.5, Rolling 12-month total (tons/year)												0.09	0.11	0.12	0.13	0.13	0.14	0.14	0.14	0.13	0.12	0.11
Onsite Fugitive PM10 (lb/day)	1.35	1.69	2.81	3.79	5.71	6.67	8.29	8.09	10.01	11.58	12.91	13.33	13.61	11.92	11.40	10.54	9.52	8.78	5.77	2.59	1.08	0.43
Onsite Fugitive PM2.5 (lb/day)	0.13	0.17	0.28	0.38	0.57	0.67	0.83	0.81	1.00	1.16	1.29	1.33	1.36	1.19	1.14	1.05	0.95	0.88	0.58	0.26	0.11	0.04

Fugitive Dust Calculations

Vehicle Weights Estimations

Estimated average vehicle weights for

Workers	2.4 ton	(CalEEMod default value; CARB Area Source Manual, 9/97)
Delivery (vendor) trucks	27.5 ton	(Average for loaded and unloaded heavy duty diesel trucks)
Haul trucks	27.5 ton	(Average for loaded and unloaded heavy duty diesel trucks)

Unpaved Road Travel Emissions Factors - Source: AP-42, Section 13.2.2, 11/06.

E = (k)[(s/12)^0.9(W/3)^0.45]*

k = particle size constant =	1.5	for PM10
k = particle size constant =	0.15	for PM2.5
s = silt fraction =	4.3	(AP-42, Table 13.2.2-1, 11/06, plant road)

Emission factors	Workers	Delivery Trucks	Haul Trucks
PM10 (lb/VMT)	0.54	1.61	1.61
PM2.5 (lb/VMT)	0.05	0.16	0.16

Unpaved Road Travel Emissions Control - Source: Control of Open Fugitive Dust Sources, Scraping, and Grading U.S EPA, 9/88

C = 100 - (0.8)(p)(d)(t)/(i)

p = potential average hourly daytime

evaporation rate =	0.845	mm/hr (EPA document, Figure 3-2, summer)
evaporation rate =	0.637	mm/hr (EPA document, Figure 3-2, annual)
t = time between applications of dust suppressants =	2	hr/application (estimated)
i = application intensity =	1.4	L/m2 (typical level in EPA document, page 3-23)

d = average hourly daytime traffic rate	Construction	T-Line
Workers Travel (vehicle/hr) =	15.0	2.5
Delivery Trucks (vehicle/hr) =	1.8	1.0
Haul Trucks (vehicle/hr) =	2.5	0.0

Notes

Construction hourly traffic estimated from average daily worker 150 trips/day, daily delivery truck 18 trips/day, haul truck 25 trips/day and 10 hr/day work day, Table 5.12-7

T-Line Construction hourly traffic estimated from average daily worker 50 trips/day, daily delivery truck 20 trips/day, received 6/9/2015

	Construction		T-Line	
Average Control Efficiency (C)	Summer	Annual	Summer	Annual
Worker Travel	85%	89%	98%	98%
Delivery Trucks	98%	99%	99%	99%
Haul Trucks	98%	98%	100%	100%

For conservative estimates, assumed "summer" control efficiency for all construction months

Fugitive Dust Calculations

Fugitive Dust Calculations for Project Site Construction

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Workers Travel																						
Workers Trips (one way trips/day)	52	64	106	152	208	232	260	316	394	478	554	584	610	536	512	472	416	384	242	110	50	20
Workers Onsite VMT (one way)	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
Control Efficiency (%)	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Controlled Fugitive Emissions																						
Onsite Fugitive - Worker PM10 (ton/month)	0.01	0.01	0.03	0.04	0.05	0.06	0.06	0.08	0.09	0.12	0.12	0.15	0.15	0.12	0.13	0.11	0.10	0.09	0.06	0.03	0.01	0.00
Onsite Fugitive - Worker PM2.5 (ton/month)	0.001	0.001	0.003	0.004	0.005	0.006	0.006	0.008	0.009	0.012	0.012	0.015	0.015	0.012	0.013	0.011	0.010	0.009	0.006	0.003	0.001	0.000
Onsite Fugitive - Worker PM10 (lb/day)	1.13	1.39	2.30	3.30	4.51	5.03	5.64	6.85	8.55	10.37	12.02	12.67	13.23	11.63	11.10	10.24	9.02	8.33	5.25	2.39	1.08	0.43
Onsite Fugitive - Worker PM2.5 (lb/day)	0.11	0.14	0.23	0.33	0.45	0.50	0.56	0.69	0.85	1.04	1.20	1.27	1.32	1.16	1.11	1.02	0.90	0.83	0.52	0.24	0.11	0.04
Delivery Trucks																						
Monthly Delivery Trucks (one way)	0	125	135	125	500	720	780	720	920	1350	1000	780	260	125	135	125	125	115	125	0	0	0
Delivery Truck Trips Length (miles, one way)	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Control Efficiency (%)	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Controlled Fugitive Emissions																						
Onsite Fugitive - Delivery Trucks PM10 (ton/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Delivery Trucks PM2.5 (ton/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Delivery Trucks PM10 (lb/day)	0.00	0.08	0.08	0.08	0.32	0.43	0.47	0.43	0.61	0.78	0.66	0.45	0.16	0.08	0.08	0.08	0.08	0.07	0.08	0.00	0.00	0.00
Onsite Fugitive - Delivery Trucks PM2.5 (lb/day)	0.00	0.01	0.01	0.01	0.03	0.04	0.05	0.04	0.06	0.08	0.07	0.05	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Haul Trucks																						
Monthly Hauling Trucks (one way)	260	250	540	500	1000	1440	2600	960	920	540	250	260	260	250	270	250	500	460	500	250	0	0
Haul Trucks Onsite VMT (one way)	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Control Efficiency (%)	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%
Controlled Fugitive Emissions																						
Onsite Fugitive - Haul Trucks PM10 (ton/month)	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Haul Trucks PM2.5 (ton/month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Onsite Fugitive - Haul Trucks PM10 (lb/day)	0.22	0.22	0.43	0.42	0.88	1.21	2.18	0.81	0.85	0.43	0.23	0.21	0.22	0.22	0.22	0.22	0.42	0.39	0.44	0.20	0.00	0.00
Onsite Fugitive - Haul Trucks PM2.5 (lb/day)	0.02	0.02	0.04	0.04	0.09	0.12	0.22	0.08	0.08	0.04	0.02	0.02	0.02	0.02	0.02	0.02	0.04	0.04	0.04	0.02	0.00	0.00

Fugitive Dust Calculations

Fugitive Dust Calculations for Transmission Line Construction

	2016							2017											2018		
	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Project Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Workers Travel																						
Workers Trips (one way trips/day)							2	40	58	58	58	28	22									
Workers Onsite VMT (mile, one way)							0.27	0.27	0.27	0.27	0.27	0.27	0.27									
Control Efficiency (%)							98%	98%	98%	98%	98%	98%	98%									
Controlled Fugitive Emissions																						
Onsite Fugitive - Worker PM10 (ton/month)							7.95E-05	1.59E-03	2.10E-03	2.41E-03	2.10E-03	1.16E-03	8.75E-04									
Onsite Fugitive - Worker PM2.5 (ton/month)							7.95E-06	1.59E-04	2.10E-04	2.41E-04	2.10E-04	1.16E-04	8.75E-05									
Onsite Fugitive - Worker PM10 (lb/day)							0.01	0.14	0.21	0.21	0.21	0.10	0.08									
Onsite Fugitive - Worker PM2.5 (lb/day)							0.00	0.01	0.02	0.02	0.02	0.01	0.01									
Delivery Trucks																						
Monthly Delivery Trucks (one way trips/month)							0	0	351	349	349	0	0									
Delivery Truck Onsite VMT (mile, one way)							0.46	0.46	0.46	0.46	0.46	0.46	0.46									
Control Efficiency (%)							99%	99%	99%	99%	99%	99%	99%									
Controlled Fugitive Emissions																						
Onsite Fugitive - Delivery Trucks PM10 (ton/month)							0	0	1.30E-03	1.29E-03	1.29E-03	0	0									
Onsite Fugitive - Delivery Trucks PM2.5 (ton/month)							0	0	1.30E-04	1.29E-04	1.29E-04	0	0									
Onsite Fugitive - Delivery Trucks PM10 (lb/day)							0	0	0.13	0.11	0.13	0	0									
Onsite Fugitive - Delivery Trucks PM2.5 (lb/day)							0	0	0.01	0.01	0.01	0	0									

Fugitive Dust Calculations for Soil Movement during Construction

Dust emission from the storage piles result from several distinct source activities, those that are related to moving fill material form SEP for storage includes

1. Loading of fill material onto storage piles (batch or continuous drop operations)
2. Wind erosion of pile surfaces and ground areas around piles.
3. Haul trucks traffic in storage area

Fill Material Storage Operations at SEP

For month 4: 10,000 cubic yards of material will be imported from offsite

For months 5 and 6: 50,000 cubic yards of material will be moved to adjacent property and stored as piles

SUMMARY (TOTAL FUGITIVE DUST EMISSIONS)	**2016**							**2017**												**2018**		
Soil Movement	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of Workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22
Total Controlled Fugitive Emissions from Loading of the fill material, Wind Erosion of Pile Surface and Haul Truck Travel to the Storage Piles																						
PM10 (ton/month)	0	0	0	7.93E-05	0.06	0.07	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.07
PM2.5 (ton/month)	0	0	0	1.20E-05	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
PM10, Rolling 12-month total (tons/year)												0.55	0.62	0.69	0.76	0.83	0.85	0.84	0.84	0.84	0.84	0.84
PM2.5, Rolling 12-month total (tons/year)												0.20	0.22	0.25	0.28	0.31	0.33	0.34	0.34	0.34	0.34	0.34
PM10 (lb/day)	0	0	0	0.07	5.15	6.12	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
PM2.5 (lb/day)	0	0	0	0.01	0.87	1.31	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84

Fugitive Dust Calculations for Soil Movement during Construction

1 Loading of fill material onto storage piles/receiving surface Emission Factors - Source: AP-42 Section 13.2.4.3, 11/06

E = k(0.0032)[(U/5)^1.3/(M/2)^1.4] (lb/ton)

k = particle size constant = 0.35 for PM10
k = particle size constant = 0.053 for PM2.5
U = mean wind speed (miles/hour) 5.82 (CalEEMod default for MDAQMD, 2.6 m/s)
M = material moisture content (%) 11 (AP-42 Table 13.2.4-1 for misc. fill material, also CalEEMod default value)

Emission factors material loading
PM10 (lb/ton) 1.25E-04
PM2.5 (lb/ton) 1.90E-05

Import fill material 10,000 cubic yards
Soil movement from SEP 50,000 cubic yards
Material density 1.26 ton/cubic yards (CalEEMod default value, Section 4.3 Appendix A)

Emission Controls Source: AP-42 Section 13.2.4.4, 11/06
For the storage operations, emissions controls typically include:
- Use of chemical wetting agents to control storage pile emissions
- Enclosure or covering of inactive piles to reduce wind erosion
- Continuous chemical treating of material loaded onto piles
- Treatment of roadways to reduce emissions from vehicle traffic in the storage pile area

Control efficiency 90% (AP-42 Section 13.2.4.4, 11/06)

1. Import of the fill material (10,000 cu yards) will occur in Month 4
Excess soil (50,000 cu yards) will be moved to the IEP during months 5 and 6

	2016							2017												2018		
	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of Workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22
Truck Loading																						
Fill material throughput [1], ton	0	0	0	12,642	31,604	31,604	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Efficiency (%)	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Controlled Fugitive Emissions																						
Truck Loading - PM10 (ton/month)	0	0	0	7.93E-05	1.98E-04	1.98E-04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Loading - PM2.5 (ton/month)	0	0	0	1.20E-05	3.00E-05	3.00E-05	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Loading - PM10 (lb/day)	0	0	0	0.07	0.19	0.18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Truck Loading - PM2.5 (lb/day)	0	0	0	0.01	0.03	0.03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Fugitive Dust Calculations for Soil Movement during Construction

2 Wind erosion of pile surfaces Emission Factors - Source: CEQA Air Quality Handbook, SCAQMD, 04/93

E = (1.7 [G/1.5][[365-H]/235]*[I/15])*J*

G = Silt content in percent 4.3 (same as silt fraction for onsite vehicle dust generation)

H = Number of days with >= 0.01 inch of precipitation per year 18 (Average year for desert, Table A9-9-E-2, CEQA Air Quality Handbook, SCAQMD, 4/93)

I = Percentage of time that unobstructed wind speed exceeds 12 miles/hour (5.34 m/s) at mean pile height 36 (estimated from wind speed data from 2009 through 2013, at 10 feet height in Blythe CA, total time for wind speed class 4 to >=10 m/s)

J = Fraction of TSP which is (estimated to be 0.5) 0.5 (Table A9-9-E, CEQA Air Quality Handbook, SCAQMD, 4/93)

Emission factors for wind erosion of storage piles

PM10 (lb/acre-day)	8.57
PM10 (lb/sq ft-day)	1.97E-04
PM2.5 (lb/sq ft-day)	7.87E-05

Total volume of the exported material	50,000	cubic yards
Total volume of the exported material	1,350,000	cubic feet (conversion factor, 1 cubic yard = 27 cubic feet)
Assume the storage piles height	15	feet
Estimated pile surface (assumed rectangular piles)	90,000	square feet

For enclose, cover, water twice daily or apply non-toxic soil binders, according to manufacturer's specifications, to exposed stock piles with 5% or greater silt content

Control Efficiency (%): 74% (Table A11-9-A, CEQA Air Quality Handbook, SCAQMD, 04/93)

Loading of excess soil to storage piles primarily occurs during months 5 and 6, for conservative estimates, assumed the storage pile remains for the rest of the project period

Assumed the storage pile operation emission controls applied

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of days per month	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31
Average monthly storage pile surface (sq ft)	0	0	0	0	22,500	45,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000	90,000
Control Efficiency (%)	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%	74%
Fugitive Emission PM10 (ton/month)	0	0	0	0	0.0178	0.0345	0.0714	0.0714	0.0645	0.0714	0.0691	0.0714	0.0691	0.0714	0.0714	0.0691	0.0714	0.0691	0.0714	0.0714	0.0645	0.0714
Fugitive Emission PM2.5 (ton/month)	0	0	0	0	0.0071	0.0138	0.0286	0.0286	0.0258	0.0286	0.0276	0.0286	0.0276	0.0286	0.0286	0.0276	0.0286	0.0276	0.0286	0.0286	0.0258	0.0286
Fugitive Emission PM10 (lb/day)	0	0	0	0	1.15	2.30	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61	4.61
Fugitive Emission PM2.5 (lb/day)	0	0	0	0	0.46	0.92	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84	1.84

Fugitive Dust Calculations for Soil Movement during Construction

3 Haul trucks traffic in storage area

Fugitive dust emission associated with haul trucks travel between the SEP project site to the storage piles in the neighboring site will be calculated as follow:

Unpaved Road Travel Emissions Factors - Source: AP-42, Section 13.2.2, 11/06.

E = (k)[(s/12)^0.9(W/3)^0.45]*

k = particle size constant = 1.5 for PM10

k = particle size constant = 0.15 for PM2.5

s = silt fraction = 8.50 (AP-42, Table 13.2.2-1, 11/06, construction sites)

Estimated average vehicle weights for haul trucks

Haul truck 33.35 tons (avg. of loaded and unloaded weights, 980H loader, Caterpillar Performance Handbook, 2006)

Emission factors	Haul Trucks
PM10 (lb/VMT)	3.25
PM2.5 (lb/VMT)	0.33

Unpaved Road Travel Emissions Control - Source: Control of Open Fugitive Dust Sources, Scraping, and Grading U.S EPA, 9/88

C = 100 - (0.8)(p)(d)(t)/(i)

p = potential average hourly daytime

evaporation rate = 0.845 mm/hr (EPA document, Figure 3-2, summer)

evaporation rate = 0.637 mm/hr (EPA document, Figure 3-2, annual)

d = average hourly daytime traffic rate

Haul Truck = 4.8 vehicles/hr (estimated from monthly haul truck trip 1000 trips/month, 22 work days/month and 10 hrs/day)

t = time between watering applications = 2 hr/application (estimated)

i = application intensity = 1.4 L/m2 (typical level in EPA document, page 3-23)

	Summer	Annual
Average Control Efficiency (C)	95.3%	96.4%

Estimated travel distance from SEP to storage piles on unpaved surface

For conservative estimates, assumed all haul truck trips occurs in month 5 are haul trips to the storage piles and same number of haul truck trips occurs in month 6 (i.e. also 1000 trips, one-way);

remaining trips in month 6 are assumed to be delivery trucks trips and fugitive dust emissions for these delivery truck trips are accounted for in onsite fugitive dust emission calculations.

For conservative estimates, assumed "summer" control efficiency for all construction months

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of Workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22
Haul Trucks																						
Monthly Hauling Trucks (one way)	0	0	0	0	1000	1000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Haul Trucks Onsite VMT (one way)	0	0	0	0	0.52	0.52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Control Efficiency (%)	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%	95.3%
Controlled Fugitive Emissions																						
Onsite Fugitive - Haul Trucks PM10 (ton/month)	0	0	0	0	0.04	0.04	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onsite Fugitive - Haul Trucks PM2.5 (ton/month)	0	0	0	0	0.00	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onsite Fugitive - Haul Trucks PM10 (lb/day)	0	0	0	0	3.81	3.64	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Onsite Fugitive - Haul Trucks PM2.5 (lb/day)	0	0	0	0	0.38	0.36	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total Fugitive Dust for Project Site Construction

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of days per month	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31
Fugitive PM10 (ton/month)	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Fugitive PM2.5 (ton/month)	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Fugitive PM10, Rolling 12-month total (tons/year)												0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Fugitive PM2.5, Rolling 12-month total (tons/year)												0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Fugitive Emission PM10 (lb/day)	0.83	0.81	0.81	0.83	0.81	0.83	0.81	0.81	0.89	0.81	0.83	0.81	0.83	0.81	0.81	0.83	0.81	0.83	0.81	0.81	0.89	0.81
Fugitive Emission PM2.5 (lb/day)	0.33	0.32	0.32	0.33	0.32	0.33	0.32	0.32	0.36	0.32	0.33	0.32	0.33	0.32	0.32	0.33	0.32	0.33	0.32	0.32	0.36	0.32

Level 2 Emission Factor

0.011 ton/acre-month [1]

22 lb/acre-month

5.05E-04 PM10 lb/sq ft-month

2.02E-04 PM2.5 lb/sq ft-month

1. Wind erosion of active construction area - Source: "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996

Wind Erosion Calculation for the Project Site Construction Area

Project Site Construction Area 25 acre
Project Site Construction Duration 22 months
Monthly Disturbed Area 1.14 acre/month
Active project area is averaged over the 22 month period to estimate monthly disturbed area

	2016							2017												2018		
	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of days per month	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31
Average monthly disturbed area (sq ft)	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500	49,500
Fugitive PM10 (ton/month)	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
Fugitive PM2.5 (ton/month)	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Fugitive PM10, Rolling 12-month total (tons/year)												0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Fugitive PM2.5, Rolling 12-month total (tons/year)												0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Fugitive Emission PM10 (lb/day)	0.83	0.81	0.81	0.83	0.81	0.83	0.81	0.81	0.89	0.81	0.83	0.81	0.83	0.81	0.81	0.83	0.81	0.83	0.81	0.81	0.89	0.81
Fugitive Emission PM2.5 (lb/day)	0.33	0.32	0.32	0.33	0.32	0.33	0.32	0.32	0.36	0.32	0.33	0.32	0.33	0.32	0.32	0.33	0.32	0.33	0.32	0.32	0.36	0.32

The Sonoran site includes 76 acres of property. Approximately 25 acres of construction laydown, material storage and parking will be required during the construction phase of the project, Section 5.1.4.4 of Draft AFC

Wind Erosion Calculation for the Transmission Line Construction Area

Project Area

Estimated Disturbed Area for T-Line Construction 331,250 sq ft From T-Line construction data received 6/9/2015

Project Duration 7 months

	2016	2017					
	DEC	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**
Project Month	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Number of days per month	31	31	28	31	30	31	30
Average monthly disturbed area (sq ft)	47,321	47,321	47,321	47,321	47,321	47,321	47,321
Fugitive PM10 (ton/month)	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Fugitive PM2.5 (ton/month)	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Fugitive PM10, 7-month total (tons/year)							0.084
Fugitive PM2.5, 7-month total (tons/year)							0.033
Fugitive Emission PM10 (lb/day)	0.77	0.77	0.85	0.77	0.80	0.77	0.80
Fugitive Emission PM2.5 (lb/day)	0.31	0.31	0.34	0.31	0.32	0.31	0.32

Construction of the Proposed SEP - CalEEMod Input Data

Project Name	SEP Construction	
District	MDAQMD	
Wind Speed	2.6	m/s
Precipitation Frequency	30	days/year
Climate Zone	10	
Urbanization Level	Rural	
Expected Operational Year	2019	
Utility Company	Southern California Edison	
CO2 Intensity Factor	630.89	
CH4 Intensity Factor	0.029	
N2O Intensity Factor	0.006	

CalEEMod Phase Name	Phase Type	Start Date	End Date	# day/Week	Number of Days	Month	# of Days, Rolling 12-month
Grading 1	Grading	6/1/2016	6/30/2016	5	22	1	
Grading 2	Grading	7/1/2016	7/31/2016	5	21	2	
Grading 3	Grading	8/1/2016	8/31/2016	5	23	3	
Grading 4	Grading	9/1/2016	9/30/2016	5	22	4	
Grading 5	Grading	10/1/2016	10/31/2016	5	21	5	
Grading 6	Grading	11/1/2016	11/30/2016	5	22	6	
Grading 7	Grading	12/1/2016	12/31/2016	5	22	7	
Grading 8	Grading	1/1/2017	1/31/2017	5	22	8	
Grading 9	Grading	2/1/2017	2/28/2017	5	20	9	
Grading 10	Grading	3/1/2017	3/31/2017	5	23	10	
Grading 11	Grading	4/1/2017	4/30/2017	5	20	11	
Grading 12	Grading	5/1/2017	5/31/2017	5	23	12	261
Grading 13	Grading	6/1/2017	6/30/2017	5	22	13	261
Grading 14	Grading	7/1/2017	7/31/2017	5	21	14	261
Grading 15	Grading	8/1/2017	8/31/2017	5	23	15	261
Grading 16	Grading	9/1/2017	9/30/2017	5	21	16	260
Grading 17	Grading	10/1/2017	10/31/2017	5	22	17	261
Grading 18	Grading	11/1/2017	11/30/2017	5	22	18	261
Grading 19	Grading	12/1/2017	12/31/2017	5	21	19	260
Grading 20	Grading	1/1/2018	1/31/2018	5	23	20	261
Grading 21	Grading	2/1/2018	2/28/2018	5	20	21	261
Grading 22	Grading	3/1/2018	3/31/2018	5	22	21	260

1. 22 months of construction for the Sonoran Energy Project

Construction of the Proposed SEP Project Site - CalEEMod Equipment Schedule Input

						2016							2017													2018		
	Fuel Type	CalEEMod Equip Type	HP	Quantity	Days on Site	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JLY	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
Project Month						1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
Construction Equipment						Number of Equipment																					
101150 Core Drill, Elect, 11HP, 8" to 18"Dia. Cores	Electric	Bore/Drill Rigs	11	1	21	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
102120 Pump, Concr, Trkmtd, 4"Line, 80' Boom	Diesel	Pump	175	2	179	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
103000 Vibrator, Concr, Gas engine, 8 HP	Gas	Cement and Mortar Mixers	8	4	179	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	0
200150 Backhoe Diesel Hyd Crawler Mount 1CY	Diesel	Tractors/Loaders/Backhoes	45	1	127	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
200450 Backhoe Loader Wheel Type, 45-60HP,3/4CY	Diesel	Tractors/Loaders/Backhoes	60	1	30	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
201910 Grader,Self-propelled,	Diesel	Graders	145	1	23	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
203050 Roller, Vibratory, smooth drum, Tandem, Gas, 35 hp	Gas	Rollers	35	1	5	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
203200 Roller Pneumatic Tire, Diesel, 80 hp	Diesel	Rollers	80	1	2	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
203350 Roller, Vibratory, smooth drum, 75 hp	Diesel	Rollers	75	1	31	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
203400 Roller, Vibratory, smooth drum, 125 hp	Diesel	Rollers	125	1	10	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
203550 Scraper, Self-Propelled, 4 X 4 Drive, Dual Engine 21 CY	Diesel	Scrapers	179	1	119	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
204260 Tractor, Crawler, w/Bulldozer, Torqueconvertor, Diesel, 200 HP	Diesel	Crawler Tractors	200	1	122	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
204310 Tractor, Crawler, convertor, Diesel, 300 HP	Diesel	Crawler Tractors	300	1	40	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
204610 Front end Loader, 4-Wheel drive, Articulated frame, 1to 1.25 CY, 70 HP	Diesel	Rubber Tired Loaders	70	1	110	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
204760 Front end Loader, 4-Wheel drive, Articulated frame, 5.25 to 5.75 CY, 270 HP	Diesel	Rubber Tired Loaders	270	1	15	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
205400 Truck, Dump Trailer Only, Rear dump, 20 CY	Diesel	Off-Highway Trucks	365	1	7	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
205500 Truck, Flatbed, 1 Axle, 3 Ton Rating	Diesel	Off-Highway Trucks	190	1	121	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0
205598 Truck, Off Hwy, Rear Dump, 34 ton cap. Note: Prorated from 35 Ton.	Diesel	Off-Highway Trucks	365	1	30	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
400300 Air Comprsr, Towed type,	Diesel	Air Compressors	50	1	105	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0
402700 Generator, Electric, Diesel Engine, 100KW	Diesel	Generator Sets	134	1	7	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
406265 Saw, Concrete, Self- propelled, Gas, 30 HP	Gas	Concrete/Industrial Saws	30	1	2	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
406800 Trailer, Platform, Flush Deck, 3 Axle, 75 Ton	Diesel	Off-Highway Trucks	175	1	61	0	0	0	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
406900 Water Tank, Engine Driven Disch, 5,000 Gals.cap.	Diesel	Other Construction Equipment	175	1	10	0	0	0	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Axle CT13 Hauling Truck 365HP	Diesel	Off-Highway Trucks	365	3	60	0	0	0	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Med Wheel Loader 962M 250HP	Diesel	Off-Highway Trucks	250	2	60	0	0	0	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
407500 Truck Tractor 6X4 40 Ton Capcty, 380HP	Diesel	Off-Highway Tractors	380	1	7	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
407600 Truck Tractor 6X4 45 Ton Capcty, 450HP	Diesel	Off-Highway Tractors	450	1	71	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0
408030 Backhoe Diesel Hyd Crawler Mount 2CY	Diesel	Tractors/Loaders/Backhoes	45	1	17	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
408135 Compactor, Vibrating Plate, Gas, 21" Plate, 5,000 lb Blow	Gas	Plate Compactors	6.5	1	153	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
408462 Tractor, Loader, Wheeled, 4X4, 1.5 - 1.75 CY, 80 HP	Diesel	Rubber Tired Loaders	80	1	21	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
420720 Truck, Pickup, 3/4 Ton, 4 Wheel Drive	Diesel	Off-Highway Trucks	175	1	21	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
504250 Paver, asphalt, wheel or crawler, 130 HP, diesel	Diesel	Pavers	130	1	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0
601200 Crane, Crawler, lattice boom, Cable, 100 TON Cap, 60' Boom	Diesel	Cranes	285	1	31	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0
601400 Crane, Crawler, Lattice Boom, 200 Ton	Diesel	Cranes	260	2	323	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	0	0	0	0	0
601500 Crane, Crawler, Lattice Boom, 350 Ton	Diesel	Cranes	450	1	197	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	0	0	0	0
602100 Crane, Truckmount, Cable, 8x4, 90 TN Cap, 15' Radius	Diesel	Cranes	476	1	141	0	0	0	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0	0	0
602500 Crane, Truck Mount, Hyd, 25 Ton Cap.	Diesel	Cranes	286	1	32	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0
602800 Crane, Self-Prpld, 4 X 4, w/Telescoping Boom, 5 Ton cap.	Diesel	Cranes	175	1	2	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0
603050 Crane, Self-Prpld, 4 X 4, w/Telescoping Boom, 20 Ton cap.	Diesel	Cranes	175	4	178	0	0	0	0	0	0	4	4	4	4	4	4	4	4	4	4	4	4	4	0	0	0
603100 Crane, Self-Prpld, 4 X 4, w/Telescoping Boom, 25 Ton cap.	Diesel	Cranes	175	1	114	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	0	0	0	0	0	0	0
603150 Crane, Self-Prpld, 4 X 4, w/Telescoping Boom, 40 Ton cap.	Diesel	Cranes	250	7	399	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total						**16**	**21**	**19**	**29**	**31**	**30**	**26**	**28**	**27**	**27**	**25**	**25**	**26**	**26**	**22**	**21**	**21**	**17**	**15**	**11**	**12**	**7**

1. Based on the construction equipment schedule received (SEP_PTA_Data_Needs Rev C), 2/20/2015

CalEEMod default load factors were used for all equipment

Construction of the Proposed SEP Transmission Line - CalEEMod Equipment Schedule Input

			2016	2017					
Equipment	**CalEEMod Equip Type**	**HP**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**
Month			**7**	**8**	**9**	**10**	**11**	**12**	**13**
Construction - Transmission Line									
Pickup Truck, 4 Wheel Drive, 240 HP	Off-Highway Trucks	240		1	2	4	6	4	2
Crane, Hydraulic, Rough Terrain, 35 Ton	Cranes	175			1	1	1		
Forklift, 10 Ton - 120 HP	Forklifts	120			1	1	1		
Forklift, 5 Ton - 94 HP	Forklifts	94			1	1	1		
Truck, Flatbed, 1 Ton - 250 HP	Off-Highway Trucks	250		1	1	1	6	5	
Truck, Flatbed, 2 Ton - 300 HP	Off-Highway Trucks	300				4	7	2	
Truck, Semi, Tractor - 435 HP	Off-Highway Trucks	435		1					
Road Grader - 179 HP	Graders	179		1					1
Fuel truck - 175 HP	Off-Highway Trucks	175		1		1	2	1	
Digger, Transmission Type, Truck Mount - 215 HP	Bore/Drill Rigs	215				2	3	1	
Back Hoe, w/ Bucket - 93 HP	Tractors/Loaders/Backhoes	93				1	2	1	
Bobcat, w/Bucket - 73 HP	Other Material Handling Equipment	73				1	1		
Truck, Concrete, 10 Yd - 175 HP	Off-Highway Trucks	175				3	3		
Truck, Flatbed, w/ Boom, 5 Ton - 300 HP	Off-Highway Trucks	300				1	2	1	
Truck, Dump, 10 Ton - 365 HP	Off-Highway Trucks	365				1	1		
Truck, Mechanics, 2 Ton - 300 HP	Off-Highway Trucks	300				1	2	1	
Truck, Semi, Tractor, w/Boom - 435 HP	Off-Highway Trucks	435				2	2		
Loader, w/Bucket - 148 HP	Tractors/Loaders/Backhoes	148				1	1		
RT Crane, Hydraulic, 20T - 175 HP	Cranes	175				1	1		
Motor, Auxiliary Power - 25 HP	Other Construction Equipment	25				1	2	1	
RT Crane, Hydraulic, 35T - 175 HP	Cranes	175					1	3	
RT Crane, Hydraulic, 150T - 345 HP	Cranes	345					1	2	
Truck, Semi, Tractor - 435 HP	Off-Highway Trucks	435					3	3	1
Truck, Flatbed w/ Bucket, 5 Ton - 300 HP	Off-Highway Trucks	300					1	1	
Tension Machine, Conductor - 135 HP	Other General Industrial Equipment	135					1	1	
Tension Machine, OPGW - 135 HP	Other General Industrial Equipment	135					1	1	
Wire Puller, Single Drum - 310 HP	Other General Industrial Equipment	310					1	1	
Wire Puller, Triple Drum - 310 HP	Other General Industrial Equipment	310					1	1	
Wire Puller, Sockline - 310 HP	Other General Industrial Equipment	310					1	1	
Dozer, Track Type, Sagging (D8 type) - 148 HP	Rubber Tired Dozers	148					1	1	
TOTAL			**0**	**5**	**6**	**28**	**56**	**32**	**4**

1. Based on the equipment schedule for transmission construction, transmission line, received 6/9/2015

CalEEMod default load factors were used for all equipment

Numbers are roundup to the nearest integer for CalEEMod calculation

Construction of the Proposed SEP Project Site - CalEEMod Vehicle Trips Input

	2016							2017												2018			
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	
Number of workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22	
Construction Labor	**Number of Workers**																						
Craft																							**Total**
Worker/Insulator												15	30	40	40	40	40	40	20	15	10		**290**
Boilmakers								20	40	60	80	80	100	80	80	70	65	55	23				**753**
Carpenters	5	10	10	15	20	20	20	15	15	15	15	12											**172**
Cement Finishers							1	2	3	4	4	3	2	1									**20**
Common Laborers	5	5	5	5	5	5	5	5	10	10	10	10	10	10	10	10	8	5	5	5	5	5	**153**
Electricians	5	5	10	10	20	20	30	30	40	40	40	40	40	40	40	30	30	30	20	10	5		**535**
Equipment Operators, Heavy	4	4	6	15	15	10	6	6	5														**71**
Equipment Operators, Light			2	2	1	1	1	1	1	1	1	1											**12**
Equipment Operators, Medium			8	10	10	22	20	20	15	15	8	8	5	5									**146**
Equipment Operators, Oilers		1	1	1	1	1	2	2	2	2	2	2	1	1	1	1	1	1	1				**24**
Mechanical Equipment																							**0**
Millwrights	2	2	4	4	8	8	10	10	8	8	4	4	1	1									**74**
Plumbers Helper						1																	**1**
Plumbers						1	1																**2**
Painters,																				4	4	4	**12**
Rodmen (Reinforcing)	4	4	4	8	8	10	20	20	10	4	4												**96**
Skilled Trade										1	1												**2**
Structural Steel Workers					10	10	10	20	20	30	40	40	40	15	10	10	5	2					**262**
Structural Steel Welders						1	1	2	3	3	3	2	1										**16**
Steamfitters/Pipefitters									20	40	60	70	70	70	70	70	55	55	50	20			**650**
Truck Drivers, Heavy			1	4	4	4	1	1	1														
Truck Drivers, Light										1													
Number of Craft Labor (Subtotal)	**25**	**31**	**51**	**74**	**102**	**114**	**128**	**154**	**193**	**234**	**272**	**287**	**300**	**263**	**251**	**231**	**204**	**188**	**119**	**54**	**24**	**9**	**3,308**
Supervision	1	1	2	2	2	2	2	4	4	5	5	5	5	5	5	5	4	4	2	1	1	1	**68**
Total Manpower	**26**	**32**	**53**	**76**	**104**	**116**	**130**	**158**	**197**	**239**	**277**	**292**	**305**	**268**	**256**	**236**	**208**	**192**	**121**	**55**	**25**	**10**	**3,376**
Worker Trips (one way trips/day)	**52**	**64**	**106**	**152**	**208**	**232**	**260**	**316**	**394**	**478**	**554**	**584**	**610**	**536**	**512**	**472**	**416**	**384**	**242**	**110**	**50**	**20**	
Worker Trips Length (miles, one way)	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	
Worker Trips, Percent Paved (%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	

Construction of the Proposed SEP Project Site - CalEEMod Vehicle Trips Input

	2016							2017												2018		
	JUN	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JLY**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**
Project Month	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**
Number of workdays	22	21	23	22	21	22	22	22	20	23	20	23	22	21	23	21	22	22	21	23	20	22
Construction Labor	**Number of Workers**																					
Delivery Trucks																						
Daily Delivery Trucks (one way)	0	5	5	5	20	30	30	30	40	50	40	30	10	5	5	5	5	5	5	0	0	0
Monthly Delivery Trucks (one way)	0	125	135	125	500	720	780	720	920	1350	1000	780	260	125	135	125	125	115	125	0	0	0
Delivery Truck Trips Length (miles, one way)	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Delivery Truck Trips, Percent Paved (%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Heavy Haul Trucks (Total per month)																						
Monthly Hauling Trucks (one way)	260	250	540	500	1000	1440	2600	960	920	540	250	260	260	250	270	250	500	460	500	250	0	0
Haul Truck Trip Length (miles, one way)	60	60	60	20	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Haul Truck Trips, Percent Paved (%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

1. Based on the workers, delivery and haul trucks schedules received (SEP_PTA_Data_Needs Rev D), 3/6/2015
   Based on the information provided (email dated 3/16/2015), the maximum daily commute for the workers that are not from Blythe will be 60 miles
   —that is, 65% of workers would commute 60 miles and 35% would commute 7 miles
2. Delivery and haul truck travel distances are estimated from the Glamis, CA to Blythe, CA via CA-78 (60 miles)

Construction of the Proposed SEP Transmission Line - CalEEMod Vehicle Trips Input

	2016	2017					
	DEC	JAN	FEB	MAR	APR	MAY	JUN
Project Month	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Construction Management / Inspection	1	2	1	1	1	1	1
Linemen		3	3	3	3	3	
Operators		15	7	7	7	10	10
Apprentice Linemen			9	9	9		
Groundmen			9	9	9		
Electricians							
Skilled trade/other							
Number of Craft Labor (Subtotal)	**1**	**20**	**29**	**29**	**29**	**14**	**11**
Worker Trips (one way trips/day)	**2**	**40**	**58**	**58**	**58**	**28**	**22**
Worker Trips Length (miles, one way)	41	41	41	41	41	41	41
Worker Trips, Percent Paved (%)	100%	100%	100%	100%	100%	100%	100%

Delivery Trucks							
Shipping days per month	26	24	23	27	25	26	26
Monthly Delivery Trucks (One way)			56	54	54		
Monthly Concrete Trucks (One way)			295	295	295		
Monthly Delivery Trucks (One way)	**0**	**0**	**351**	**349**	**349**	**0**	**0**
Daily Delivery Trucks (One way trips/day)	**0**	**0**	**15**	**13**	**14**	**0**	**0**
Delivery Truck Trips Length (miles)	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Delivery Truck Trips, Percent Paved (%)	100%	100%	100%	100%	100%	100%	100%

Worker trips and truck trips length are assumed to be the same as during construction period.

Based on the information provided (email dated 3/16/2015), the maximum daily commute for the workers that are not from Blythe will be 60 miles —that is, 65% of workers would commute 60 miles and 35% would commute 7 miles

Delivery and haul truck travel distances are estimated from the Glamis, CA to Blythe, CA via CA-78 (60 miles)

Appendix 3.1D
Best Available Control Technology

APPENDIX 3.1D

Best Available Control Technology

The gas turbine proposed for the SEP is required to use best available control technology (BACT) in accordance with the requirements of Mojave Desert Air Quality Management District (MDAQMD, or District) rules and the federal Prevention of Significant Deterioration (PSD) regulations. BACT is defined in MDAQMD Rule 1301(K) as follows:

"***Best Available Control Technology (BACT)***" *For any Permit Unit at Facilities as indicated below:*

> *(1) For a new or Modified Major Facility as defined in District Rule 1301(DD) the most stringent of:*
>
> > *(a) The most stringent emission limit or control technique which has been achieved in practice, for such permit unit class or category of source; or*
> >
> > *(b) Any other emission limitation or control technique, and/or different fuel demonstrated in practice to be technologically feasible and cost-effective by the APCO or by CARB.*
>
> *(2) For a new or Modified non-major Facility:*
>
> > *(a) The most stringent emission limit or control technique which has been achieved in practice for such category or class of source. Economic and technical feasibility may be considered in establishing the class or category of source; or*
> >
> > *(b) Any other emission limitation or control technique found by the APCO to be technologically feasible and cost effective for such class or category of source.*
>
> *(3) Under no circumstances shall BACT be determined to be less stringent than the emission limitation or control technique contained in any State Implementation Plan as approved by USEPA, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable.*
>
> *(4) In no event shall the application of BACT result in the emissions of any Regulated Air Pollutant which exceeds the emissions allowed by any applicable standard or other requirement under 42 U.S.C. §7411, Standards of Performance for New Stationary Sources (Federal Clean Air Act §111) or 42 U.S.C. §7412, Hazardous Air Pollutants (Federal Clean Air Act §112) or the regulations promulgated thereunder."*

Since SEP will be a modification to an existing major facility (as defined in District rules)[1], the provisions of subsections 1 and 3 are applicable.

As discussed in Section 3.1.6.3, the SEP gas turbine will trigger BACT requirements for NOx, SOx, VOC, and PM_{10}. BACT review is also required for the cooling tower and for NOx emissions from the emergency firepump engine. The emission rates and control technologies determined to be BACT for this project are discussed in detail in the following sections. For the CTG, separate determinations are provided for normal operation and startup/shutdown operation.

[1] The existing facility is a Major Facility as defined in District Rule 1301(DD); however, it is not a major stationary source for purposes of Federal PSD requirements.

3.1.1 Steps in a Top-Down BACT Analysis

Step 1 – Identify All Possible Control Technologies

The first step in a top-down analysis is to identify, for the emissions unit and pollutant in question, all available control options. Available control options are those air pollution control technologies or techniques, including alternate basic equipment or processes, with a practical potential for application to the emissions unit in question. The control alternatives should include not only existing controls for the source category in question, but also, through technology transfer, controls applied to similar source categories and gas streams.

BACT must be at least as stringent as what has been achieved in practice (AIP) for a category or class of source. Additionally, EPA guidelines require that a technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust stream controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Candidate control options that do not meet basic project requirements (i.e., alternative basic designs that “redefine the source”) are eliminated at this step.

Step 2 – Eliminate Technologically Infeasible Options

To be considered, the candidate control option must be technologically feasible for the application being reviewed.

Step 3 – Rank Remaining Control Options by Control Effectiveness

All feasible options are ranked in the order of decreasing control effectiveness for the pollutant under consideration. In some cases, a given control technology may be listed more than once, representing different levels of control (e.g., the use of SCR for control of NOx may be evaluated at 2 and 2.5 parts per million by volume, dry [ppmvd]). Any control option less stringent than what has been already achieved in practice for the category of source under review must also be eliminated at this step.

Step 4 – Evaluate Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

To be required as BACT, the candidate control option must be cost effective, considering energy, environmental, economic, and other costs. The most stringent control technology for control of one pollutant may have other undesirable environmental or economic impacts. The purpose of Step 4 is to either validate the suitability of the top control option or provide a clear justification as to why that option should not be selected as BACT.

Once all of the candidate control technologies have been ranked, and other impacts have been evaluated, the most stringent candidate control technology is deemed to be BACT, unless the other impacts are unacceptable.

Step 5 – Determine BACT/Present Conclusions

BACT is determined to be the most effective control technology subject to evaluation, and not rejected as infeasible or having unacceptable energy, environmental, or cost impacts.

3.1.2 BACT for the Gas Turbine: Normal Operations

3.1.2.1 NOx EMISSIONS

Step 1 – Identify All Possible Control Technologies

The emissions unit for which BACT is being considered is a combined-cycle gas turbine with a nominal output of 553 MW.

Potential control technologies were identified by searching the following sources for determinations pertaining to combustion gas turbines:

- MDAQMD BACT Guidance;
- SCAQMD BACT Guidelines;
- San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Clearinghouse;
- Bay Area Air Quality Management District (BAAQMD) BACT Guidelines;
- EPA Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emission Rate (LAER) Clearinghouse;
- Other district and state BACT Guidelines; and
- BACT/LAER requirements in New Source Review permits issued by a local air district[2] or other air pollution control agency.

Outlined below are the technologies for control of NOx that were identified.

- Low NOx burner design (e.g., dry low NOx (DLE) combustors)
- Water or steam injection
- A Selective Catalytic Reduction (SCR) system capable of continuously complying with a limit of 2.0 ppmvd @15% oxygen (O_2) (1-hour average)
- An EMx (formerly SCONOx) system capable of continuously complying with a limit of 2.0 ppmvd @15% O_2 (1-hour average)
- Alternative Basic Equipment:
    - Renewable Energy Source (e.g., solar, wind, etc.)

It should be noted that the use of renewable energy in lieu of a combined-cycle gas turbine would "redefine the source." Renewable energy facilities require significantly more land to construct, and need to be located in areas with very specific characteristics. Wind and solar facilities have power generation profiles that cannot match demand; conventional power plants are needed in order to follow demand. The capital costs for wind or solar facilities are substantially higher than for a comparable conventional facility, making financing of such a project significantly different. Finally, one of the fundamental objectives of the proposed SEP is to provide baseload capacity, making the use of renewable energy for the project fundamentally incompatible with the project objective. Nevertheless, these technologies are feasible, and the technical feasibility of renewable energy sources for this specific application will be considered in Step 2.

Step 2 – Eliminate Technologically Infeasible Options

Exhaust Stream Controls

---

[2] Any Air Quality Management District or Air Pollution Control District in California.

The most recent NOx BACT listings for combined-cycle combustion turbines in this size range are summarized in Table 3.1D-1. The most stringent NOx limit in these recent BACT determinations is a 2.0 ppm[3] limit averaged over a 1-hour averaging period, excluding startups and shutdowns. This level is achieved using a dry low-NOx combustor and SCR. The GE 7HA.02 gas turbine proposed for this project will use dry low-NOx (DLE) emissions technology, which yields turbine-out NOx concentrations as low as 25 ppmvd @ 15% O2, which is comparable to the turbine-out NOx levels for current-generation water-injected gas turbines.

EMx is a NOx reduction system distributed by EmeraChem. This system uses a single catalyst to oxidize both NO and CO, a second catalyst system to absorb NO_2, and then a regeneration system to convert the NO_2 to N_2 and water vapor. The EMx system does not use ammonia as a reagent. The EMx process has been demonstrated in practice on smaller gas turbines, including Redding Electric Utility's (REU) Units 5 and 6 which are comprised of a 43-MW Alstom GTX100 and a 45 MW Siemens SGT 800 combined-cycle gas turbine, respectively. While the technology has never been demonstrated on a gas turbine the size of the GE 7HA.02, the technology is considered by the manufacturer to be scalable.

The SCR system uses ammonia injection to reduce NOx emissions. SCR systems have been widely used in combined-cycle gas turbine applications of all sizes. The SCR process involves the injection of ammonia into the flue gas stream via an ammonia injection grid upstream of a reducing catalyst. The ammonia reacts with the NOx in the exhaust stream to form N_2 and water vapor. The catalyst does not require regeneration, but must be replaced periodically; typical SCR catalyst lifetimes are in excess of three years.

Either SCR or EMx technology is capable of achieving a NOx emission level of 2.5 ppmvd @ 15% O_2. Neither has been demonstrated to consistently achieve lower emission levels in combined-cycle turbines in demand-response service. Both technologies are evaluated further in Step 3.

Table 3.1D-1

Recent NOx BACT Determinations for Large Combined-Cycle Combustion Turbines

Facility	District	NOx Limit[a]	Averaging Period	Control Method Used	Date Permit Issued	Source
Inland Empire Energy Center (GE 107H with duct firing)	SCAQMD	2.0	1 hr	SCR	2003	CEC Siting Div website
El Segundo Power Redevelopment Project (GE 7FA, no duct firing)	SCAQMD	2.0	1 hr	SCR	2010	CEC Siting Div website
GWF Tracy Combined Cycle Power Plant Project (GE 7EA with duct firing)	BAAQMD	2.0	1 hr	SCR	2010	CEC Siting Div website
Oakley Generating Station (GE 7FA)	BAAQMD	2.0	1 hr	SCR	2011	CEC Siting Div website
Watson Cogeneration (GE 7EA with duct firing)	SCAQMD	2.0	1 hr	SCR	2012	CEC Siting Div website

[3] All turbine/HRSG exhaust emissions concentrations shown are as ppm by volume, dry, corrected to 15% O_2.

Table 3.1D-1
Recent NOx BACT Determinations for Large Combined-Cycle Combustion Turbines

Facility	District	NOx Limit[a]	Averaging Period	Control Method Used	Date Permit Issued	Source
Sunbury Generation LP (F class turbines with duct firing)	Pennsylvania DEP	2.0	1 hr	SCR	2014	RBLC website
Marshalltown Generating Station (Siemens SGT6-5000F, no duct firing)	Iowa DNR	2.0	30 days	SCR	2014	RBLC website

Note:
a. All concentrations expressed as parts per million by volume dry, corrected to 15% O_2.

Alternative Basic Technology

Solar Thermal

Solar thermal facilities collect solar radiation, then heat a working fluid (water or a hydrocarbon liquid) to create steam to power a steam turbine generator. All solar thermal facilities require considerable land for the collection field and are best located in areas of high solar incident energy per unit area. In addition, power is generated only while the sun shines, so the units do not supply power at night or on cloudy days. A solar power plant would not meet the project's objective of providing baseload capability that would be available at all times. For these reasons, a solar thermal power plant is rejected as BACT for this application.

Wind

Wind power facilities use a wind-driven rotor to turn a generator to generate electricity. Only limited sites in California have an adequate wind resource to allow for the economic construction and operation of large-scale wind generators. Most of these sites have already been developed or are remote from electric load centers and have little or no transmission access. Even in prime locations the wind does not blow continuously, so power is not always available. Due to the lack of availability of good sites, limited dependability, and relatively high cost, this technology is not feasible for this project. Furthermore, a wind power plant would not meet the project's objective of providing baseload power. For these reasons, a wind power plant is rejected as BACT for this application.

Other alternatives

A number of other alternative generating systems are described in the Alternatives Analysis Section (Section 3.16) of the petition to amend. These additional analyses failed to identify an alternative generating technology that was technically feasible for this site and that would meet the project's objectives.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Both SCR and EMx technologies, each in combination with combustion controls, are capable of achieving a NOx emission level of 2.0 ppmvd @ 15% O_2. They are therefore ranked together in terms of control effectiveness, and the evaluation of these technologies continues in Step 4.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15% O_2. A health risk screening analysis of the proposed project using air dispersion modeling was prepared to demonstrate that both the acute health hazard index and the chronic health hazard index are much less than 1, based on an ammonia slip limit of 5 ppmv @ 15% O_2. In accordance with currently accepted practice, a hazard index below 1.0 is not considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant, and is not a sufficient reason to eliminate SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of aqueous or anhydrous ammonia.[4] Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The project operator will be required to develop and maintain a Risk Management Plan (RMP) and to implement a Risk Management Program to prevent accidental releases of ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and proven industry safety codes and standards. Thus, the potential environmental impact due to aqueous ammonia use at the Project is minimal and does not justify the elimination of SCR as a control alternative.

Regeneration of the EMx catalyst is accomplished by passing hydrogen gas over an isolated catalyst module. The hydrogen gas is generated by reforming steam, so some of the steam from the auxiliary boiler or the HRSG would have to be diverted for this use. This would result in additional natural gas consumption, and increased emissions, per megawatt hour of electricity produced.

"Achieved in Practice" Criteria

In general, the method for determining when emission control technologies are achieved in practice (AIP) is similar in each District. The SCAQMD has established formal criteria for determining when emission control technologies should be considered AIP for the purposes of BACT determinations. The criteria include the elements outlined below.

- Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guarantee must be available with the purchase of the control technology, as well as parts and service.
- Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50% design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.
- Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Each of these criteria is discussed separately below for SCR and for EMx.

<u>SCR Technology</u> – SCR has been achieved in practice at numerous combustion turbine installations throughout the world. There are numerous combined-cycle gas turbine projects that limit NOx emissions to 2.0 ppmc using SCR technology, as shown in Table 3.1D-1. An evaluation of the

[4] The Project proposes to use the less concentrated, safer aqueous form of ammonia.

proposed AIP criteria as applied to the achievement of 2.0 ppmc, and to extremely low NOx levels (below 2.0 ppmc) using SCR technology, is summarized below.

- Commercial Availability: Turbine-out NOx from the GE 7HA.02 gas turbine is generally guaranteed at 9 ppmc. Achieving a controlled NOx limit below 2 ppmc on a 1-hour average basis would require SCR technology to achieve reductions greater than 75 percent. However, it is not clear that a commercial guarantee would be available for NOx levels below 2 ppm. As shown in Table 3.1D-1 above, this criterion is satisfied at a 2.0 ppmc permit level.
- Reliability: SCR technology, in combination with combustion controls, has been shown to be capable of achieving NOx levels consistent with a 2.0 ppmc permit limit during extended, routine operations at many commercial power plants. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability. There has been no demonstration of operation at levels below 2.0 ppmc on a 1-hour average basis during extended, routine operation; consequently, this criterion is not satisfied for NOx limits below 2.0 ppmc.
- Effectiveness: SCR technology has been demonstrated to achieve NOx levels of 2.0 ppmc with H-class turbines, but not at lower limits for this generating technology. Short-term excursions have resulted in NOx concentrations above the permitted level of 2.0 ppmc; however, these excursions are not frequent and have not been associated with diminished effectiveness of the SCR system. Rather, these excursions typically have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed or with malfunctions of the ammonia injection system. Consequently, this criterion is satisfied at a NOx limit of 2.0 ppmc, but not at lower NOx limits.
- Conclusion: SCR technology capable of achieving NOx levels of 2.0 ppmc is considered to be achieved in practice. The permit limits for the proposed project CTGs include a NOx limit of 2.0 ppmc on a 1-hour average basis. This proposed limit is consistent with the available data. The AIP criteria are not met for SCR on large combined-cycle gas turbines at NOx limits lower than 2.0 ppmc.

<u>EMx Technology</u> – EMx has been demonstrated in service in five applications: the Sunlaw Federal cogeneration plant, the Wyeth BioPharma cogeneration facility, the Montefiore Medical Center cogeneration facility, the University of California San Diego facility, and the City of Redding Power Plant. The combustion turbines at these facilities are much smaller than for the proposed project turbine. The largest installation of the EMx system is at the Redding Power Plant. The Redding Power Plant includes two combined-cycle combustion turbines—a 43 MW Alstom GTX100 with a permitted NOx emission rate of 2.5 ppmc (Unit 5), and a 45 MW Siemens SGT 800 with a permitted NOx emission rate of 2.0 ppmc (Unit 6).

A review of NOx continuous emissions monitoring (CEM) data obtained from the EPA's Acid Rain program website[5] indicates a <u>mean</u> NOx level for the Redding Unit 5 of less than 1.0 ppm during the period from 2002 to 2007, but not continuous compliance with a 2.5 ppmc limit. After the first year of operation, Unit 5 experienced only a few hours of non-compliance per year (less than 0.1% of the annual operating hours exceed that plant's NOx permit limit of 2.5 ppmc). The experience at the City of Redding Plant indicates the ability of the EMx system to control NOx emissions to levels of 2.5 ppmc. These data do not indicate the ability to consistently achieve NOx levels below 2.0 ppm on a 1-hour average basis, notwithstanding the lower annual average concentration. This is due to the cyclical nature of EMx NOx levels between plant shutdowns and scheduled catalyst cleanings.

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[5] Available at *http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=prepackaged.results*.

Redding Unit 6 started up on October 2011. A review of annual Title V compliance certification reports for the unit indicates that the number of NOx emissions-related deviations has declined between 2012 and 2014. The deviations during the early years were generally related to the inability of the EMx system to achieve control of NOx emissions within the 2-hour startup period allowed by the permit, and not to any failure to maintain the 2.0 ppmc limit during routine operation. However, based on the Rapid Response startup design employed on the SEP gas turbine and resulting start times of under one hour, the startup issues experienced at Redding Unit 6 suggest that the EMx NOx control technology could not be successfully applied to the proposed project.

Based on this information, the following paragraphs evaluate the proposed AIP criteria as applied to the achievement of low NOx levels (2.0 ppmc) using EMx technology.

- Commercial Availability: While a proposal has not been sought, presumably EmeraChem would offer standard commercial guarantees for the proposed project. Consequently, this criterion is expected to be satisfied.
- Reliability: Redding Unit 5 was originally permitted with a 2.0 ppmc permit limit. It was subsequently found that the unit could not maintain compliance with a 2.0 ppmc limit on a consistent basis, and the limit was eventually changed to 2.5 ppmc. As discussed above, based on a review of the CEM data for Redding Unit 5, the EMx system complied with the 2.5-ppmc NOx permit limit but with a few hours each year of excess emissions (approximately 3% of annual operating hours following the first year, and approximately 2% following the second year, dropping to approximately 0.1% after 4 years). This level of performance was also associated with some significant operating and reliability issues. According to a June 23, 2005 letter from the Shasta County Air Quality Management District,[6] repairs to the EMx system began shortly after initial startup and continued during several years of operation. Redesign of the EMx system was required due to a problem with the reformer reactor combustion production unit that led to sulfur poisoning of the catalyst, despite the sole use of low-sulfur, pipeline quality natural gas as the turbine fuel. In addition, the EMx system catalyst washings had to occur at a frequency several times higher than anticipated during the first three years of operation, which resulted in substantial downtime of the combustion turbine. Since the REU installations are the most representative of all of the EMx-equipped combustion turbine facilities for comparison to the proposed Project, the problems encountered at REU—especially the startup issues experience by Unit 6-- bring into question the reliability of the EMx system for the proposed project.
- Effectiveness: The EMx system at REU Unit 5 has recently been able to demonstrate compliance with a NOx level of 2.5 ppmc, and the newer REU Unit 6 has been permitted with a 2.0 ppmc NOx limit. As discussed above, there have been no known excursions beyond the permit limit for Unit 6 in the recent limited operation; however, the startup issues experienced by Unit 6 suggest that the EMx system would not be compatible with the Rapid Response gas turbine design.

  There is an additional issue with the application of EMx technology to the proposed project. Steam is needed as a carrier gas for the regeneration hydrogen. As a result, the project would have to divert some of the steam from the auxiliary steam boiler or from the HRSG for use in the regeneration process. This would require additional use or an increase in the size of the auxiliary boiler, with resulting increases in natural gas fuel use and emissions, or a

[6] Letter dated June 23, 2005, from Shasta County Air Quality Management District to the Redding Electric Utility regarding Unit 5 demonstration of compliance with its NOx permit limit.

reduction in steam turbine output. Either approach would result in reduced overall plant efficiency as well as higher criteria and GHG emissions.

- Conclusion: EMx systems may be capable of achieving NOx levels of 2.0 ppmc and less. However, the operating history does not support a conclusion that this technology is achieved in practice at this emission level, based on the above guidelines.

Summary of Achieved in Practice Evaluation

SCR's capability to consistently achieve 2.0 ppmc NOx (1-hour average) in large, combined-cycle gas turbines has been demonstrated by numerous installations. EMx's ability to consistently achieve a NOx emission rate below 2.0 ppmc in large turbines has not been demonstrated. An emission level of 2.0 ppmc NOx has therefore been achieved in practice, and any BACT determination must be at least as stringent as that.

Technologically Feasible/Cost Effective Criterion

No candidate technology with lower emission levels than those achieved in practice has been identified.

Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the NOx BACT determinations of 2.0 ppmc on a 1-hour average basis made for recently permitted combined-cycle gas turbine projects in SCAQMD, BAAQMD, SJVAPCD and elsewhere reflect the most stringent NOx emission limit that has been achieved in practice. No more stringent level has been suggested as being technologically feasible. Therefore, BACT/LAER for NOx for this application is any technology capable of achieving 2.0 ppmc on a 1-hour average basis.

Both SCR and EMx are expected to achieve the proposed BACT NOx emission limit of 2.0 ppmc averaged over one hour. However, concerns remain regarding the long-term effectiveness of EMx as a control technology because the technology has not been demonstrated on a long-term basis or on a fast-start gas turbine. For the reasons described in the "achieved in practice" discussion above, EMx technology is eliminated as BACT and SCR has been selected as the NOx control technology to be used for the Project.

The gas turbine used for the proposed project will be designed to meet a NOx level of 2.0 ppmc on a 1-hour average basis using SCR.

3.1.2.2 VOC EMISSIONS

Step 1 – Identify All Possible Control Technologies

Most VOCs emitted from natural gas-fired turbines are the result of incomplete combustion of fuel. Therefore, most of the VOCs are methane and ethane, which are not effectively controlled by an oxidation catalyst. However, oxidation catalyst technology designed to control CO can also provide some degree of control of VOC emissions, especially the more complex and toxic compounds formed in the combustion process. Therefore, the use of good combustion practices is generally considered BACT for VOC, with some additional benefit provided by an oxidation catalyst.

Alternative basic equipment—including renewable energy sources, such as solar and wind, and combined cycle technology—was already discussed above (Step 1 for NOx BACT on the CTGs). For the same reasons, solar, wind and other renewable energy sources are rejected as VOC BACT for this application.

Step 2 – Eliminate Technologically Infeasible Options

The only technology under consideration is combustion controls, with some additional benefit provided by an oxidation catalyst. This combination of technologies has been demonstrated to be feasible in many applications. No other technologies have been identified that are capable of achieving the same level of control. As a result, the goal of the rest of this analysis is to determine the appropriate emission limit that constitutes BACT for this application.

CARB's BACT guidance document for electric generating units rated at greater than 50 MW indicates that BACT for the control of VOC emissions for combined-cycle and cogeneration power plants is 2 ppmvd @ 15% O_2. A summary of recent CARB BACT guidance is shown in Table 3.1D-2.

Table 3.1D-2
CARB BACT Guidance For Power Plants

Pollutant	BACT
Nitrogen Oxides	2.5 ppmv @ 15% O_2 (1-hour average) or 2.0 ppmv @ 15% O_2 (3-hour average)
Sulfur Dioxide	Fuel sulfur limit of 1.0 grains/100 scf
Carbon Monoxide	6 ppmv @ 15% O_2 (3-hour average)
VOC	2 ppmv @ 15% O_2 (1-hour average)
NH_3	5 ppmv @ 15% O_2 (3-hour average)
PM_{10}	Fuel sulfur limit of 1.0 grains/100 scf

The SJVAPCD's BACT guidelines contain a determination for gas turbines rated at larger than 50 MW with uniform load and without heat recovery. The SJVAPCD concluded that a VOC exhaust concentration of 2.0 ppmvd @ 15% O_2 constituted BACT that had been achieved in practice, while 0.6 to 1.3 ppmvd @ 15% O_2 is considered technologically feasible.

Published prohibitory rules from the BAAQMD, SMAQMD, SDCAPCD, SJVAPCD, and SCAQMD were reviewed to identify the VOC standards that govern existing natural gas-fired combined-cycle combustion gas turbines. None of the prohibitory rules for combustion gas turbines specify an emission limit for VOC. The applicable NSPS (40 CFR 60 Subpart KKKK) does not include a VOC limit.

A summary of recent VOC BACT determinations is shown in Table 3.1D-3.

Table 3.1D-3
Recent VOC BACT Determinations for Large Combined-Cycle Combustion Turbines

Facility	District	VOC Limit[a]	Averaging Period	Control Method Used	Date Permit Issued	Source
Inland Empire Energy Center (GE 107H with duct firing)	SCAQMD	2.0	1 hr	Oxidation catalyst	2003	CEC Siting Div website
Avenal Power Center LLC (GE 7FA with duct firing)	SJVAPCD	2.0 w/ duct firing; 1.4 w/o duct firing	3 hrs	Oxidation catalyst	2008	CEC Siting Div website
El Segundo Power Redevelopment Project (GE 7FA, no duct firing)	SCAQMD	2.0	1 hr	Oxidation catalyst	2010	CEC Siting Div website

Table 3.1D-3
Recent VOC BACT Determinations for Large Combined-Cycle Combustion Turbines

Facility	District	VOC Limit[a]	Averaging Period	Control Method Used	Date Permit Issued	Source
GWF Tracy Combined Cycle Power Plant Project (GE 7EA with duct firing)	BAAQMD	2.0 w/ duct firing; 1.5 w/o duct firing	3 hrs	Oxidation catalyst	2010	CEC Siting Div website
Oakley Generating Station (GE 7FA, no duct firing)	BAAQMD	1.0	3 hrs	Oxidation catalyst	2011	CEC Siting Div website
Watson Cogeneration (GE 7EA with duct firing)	SCAQMD	2.0	1 hr	Oxidation catalyst	2012	CEC Siting Div website
Sunbury Generation LP (F class turbines with duct firing)	Pennsylvania DEP	2.0	unknown	Oxidation catalyst	2014	RBLC website
Marshalltown Generating Station (Siemens SGT6-5000F, no duct firing)	Iowa DNR	2.0	30 days	Oxidation catalyst	2014	RBLC website

Note:
a. All concentrations expressed as parts per million by volume dry, corrected to 15% O_2 (ppmc).

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control technologies under consideration are ranked as follows:

- 1.0 ppmvd @ 15% O_2, 3-hour average, without duct firing;
- 1.4 ppmvd @ 15% O_2, 3-hour average, without duct firing; and
- 2.0 ppmvd @ 15% O_2, 3-hour average, with duct firing.

The lowest VOC limit that applies during duct firing is 2.0 ppmc. Although the Oakley project was permitted with a VOC limit of 1.0 ppmc, that project has not been constructed or operated, so the limit has not yet been achieved in practice. In addition, the Oakley project is not equipped with duct firing. An averaging period of less than 3 hours is not reasonable, since compliance with the VOC limit will be demonstrated through source testing, which consists of three one-hour test runs.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the top alternative listed in the previous step is inappropriate as BACT.

The Applicant has proposed to meet a 2.0 ppmc limit on a 3-hour average basis during duct firing, and a 1.0 ppmc limit on a 3-hour average basis without duct firing. These levels are consistent with the VOC BACT determinations summarized in Table 3.1D-3, and therefore meet BACT.

Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent achieved in practice, required in a federal NSPS or district prohibitory rule, or considered technologically feasible. Based upon the results of this analysis, the VOC emission limits of 2.0 ppmc during duct firing and 1.0 ppmc without duct firing are considered to be BACT for the proposed project.

3.1.2.3 SULFUR OXIDE EMISSIONS

Step 1 – Identify All Possible Control Technologies

Natural gas fired combustion turbines have inherently low SOx emissions due to the small amount of sulfur present in the fuel. With typical pipeline quality natural gas sulfur content well below 1 grain/100 scf, the SOx emissions for natural gas fired combustion turbines are orders of magnitude less than oil-fired turbines. Firing with natural gas, and the resulting control of SOx emissions, has been used by numerous combustion turbines throughout the world. Due to the prevalence of the use of natural gas to control SOx emissions from combustion turbines, only an abbreviated discussion of post-combustion controls will be addressed in this section.

Post-combustion SOx control systems include dry and wet scrubber systems. These types of systems are typically installed on high SOx emitting sources such as coal-fired power plants. Post-combustion control systems for combustion turbines also include ESx catalyst systems. These systems trap the sulfur in the exhaust stream on an ESx catalyst. During a regeneration process, the sulfur is removed from the ESx catalyst and is either reintroduced back into the exhaust stream or sent to a sulfur scrubbing system. If the sulfur removed from the ESx catalyst is reintroduced back into the exhaust stream, there is no SOx control associated with the system.

Step 2 – Eliminate Technically Infeasible Options

All of the control options discussed above are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The typical SOx control level for a well-designed wet or dry scrubber installed on a coal-fired boiler ranges from approximately 70% to 90%,[7] with some installations achieving even higher control levels. According to EmeraChem literature,[8] the ESx system is capable of removing approximately 95% of the SOx emissions from the exhaust stream of natural gas fired combustion turbines. With the sulfur scrubber option, during the regeneration cycle of the ESx system the sulfur captured on the ESx catalyst is sent to a sulfur-scrubbing unit. A high-efficiency sulfur-scrubbing unit would achieve a control level similar to that of the wet/dry scrubbers discussed above.

Step 4 – Evaluate Most Effective Controls and Document Results

The use of low sulfur content pipeline natural gas has been achieved in practice at numerous combustion turbine installations throughout the world, and the use of this fuel minimizes SOx emissions. While it would be theoretically feasible to install some type of post-combustion control such as a dry/wet scrubber system or an ESx catalyst with a sulfur scrubber on a natural gas fired turbine, due to the inherently low SOx emissions associated with the use of natural gas, these systems are not cost effective and regulatory agencies do not require them. Consequently, no further discussion of post-combustion SOx control is necessary.

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[7] Air and Waste Management Association, *Air Pollution Control Manual*, Second Edition, page 206.

[8] High Performance EMx Emissions Control Technology for Fine Particles, NOx, CO, and VOCs from Combustion Turbines and Stationary IC Engines, by Steven DeCicco and Thomas Girdlestone, EmeraChem Power, June 2008, page 19.

Step 5 – Determine BACT/Present Conclusions

BACT for this project is the use of pipeline-quality natural gas. The SOx control method for the proposed project is the use of pipeline-quality natural gas. Consequently, the proposed project is consistent with BACT requirements.

3.1.2.4 PM/PM_{10}/$PM_{2.5}$ EMISSIONS

Step 1 – Identify All Possible Control Technologies

Alternative basic equipment—including renewable energy sources, such as solar and wind—has also been identified as a technology for the control of PM/PM_{10}/$PM_{2.5}$ emissions. Such alternative basic equipment was already discussed above (Step 1 for NOx BACT on the CTGs/HRSGs). For the same reasons, solar, wind and other renewable energy sources are rejected as PM_{10}/$PM_{2.5}$ BACT for this application.

Achievable Controlled Levels and Available Control Options

PM emissions from natural gas-fired turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are minimized by using clean-burning pipeline quality natural gas with low sulfur content.

The CARB BACT Clearinghouse, as well as the BAAQMD BACT guideline, identifies the use of natural gas as the primary fuel as "achieved in practice" for the control of PM_{10}/$PM_{2.5}$ for combustion gas turbines.

CARB's BACT guidance document for stationary gas turbines used for power plant configurations[9] indicates that BACT for the control of PM emissions is an emission limit corresponding to natural gas with a fuel sulfur content of no more than 1 grain/100 standard cubic foot.

Title 40 CFR Part 60 Subpart KKKK contains the applicable NSPS for combustion gas turbines. Subpart KKKK does not regulate PM_{10}/$PM_{2.5}$ emissions.

Published prohibitory rules from the SCAQMD, SJVAPCD, SMAQMD, and SDCAPCD were reviewed to identify the PM_{10} standards that govern natural gas-fired combustion gas turbines. These prohibitory rules do not regulate PM_{10}/$PM_{2.5}$ emissions. Recent PM_{10}/$PM_{2.5}$ BACT determinations for combined-cycle gas turbines are summarized in Table 3.1D-4.

Table 3.1D-4

Recent PM_{10}/$PM_{2.5}$ BACT Determinations for Combined-Cycle Combustion Turbines

Facility	District	PM BACT Determination	Date Permit Issued	Source
Inland Empire Energy Center (GE 107H with duct firing)	SCAQMD	10 lb/hr (equivalent to 0.00385 lb/MMBtu)	2005 (amendment)	CEC Staff Analysis of Proposed Modifications
Avenal Power Center LLC (GE 7FA with duct firing)	SJVAPCD	11.78 lb/hr w/ duct firing; 8.91 lb/hr w/o duct firing	2009	EPA Region 9 PSD Permit AAQIR
El Segundo Power Redevelopment Project (GE 7FA, no duct firing)	SCAQMD	9.5 lb/hr (equivalent to 0.0045 lb/MMBtu at peak load)	2010	CEC Siting Div website

[9] CARB, Guidance for Power Plant Siting and Best Available Control Technology, July 22, 2009, Table I-1. Available at http://www.arb.ca.gov/energy/powerpl/appdfin.pdf

Table 3.1D-4
Recent $PM_{10}/PM_{2.5}$ BACT Determinations for Combined-Cycle Combustion Turbines

Facility	District	PM BACT Determination	Date Permit Issued	Source
GWF Tracy Combined Cycle Power Plant Project (GE 7EA with duct firing)	BAAQMD	Natural gas fuel (permitted limits are 5.8 lb/hr w/ duct firing; 4.4 lb/hr w/o duct firing) (equivalent to 0.007 lb/MMBtu)	2010	CEC Siting Div website
Oakley Generating Station (GE 7FA, no duct firing)	BAAQMD	Exclusive use of natural gas	2011	CEC Siting Div website
Watson Cogeneration (GE 7EA with duct firing)	SCAQMD	Natural gas fuel	2012	CEC Siting Div website
Sunbury Generation LP (F class turbines with duct firing)	Pennsylvania DEP	0.0088 lb/MMBtu (equivalent to ~22 lb/hr)	2014	RBLC website
Marshalltown Generating Station (Siemens SGT6-5000F, no duct firing)	Iowa DNR	0.01 lb/MMBtu (equivalent to ~22.5 lb/hr)	2014	RBLC website

This “top-down” $PM_{10}/PM_{2.5}$ BACT analysis will consider the following emission limitations:

- 10 lb/hr with duct firing; 8 lb/hr without duct firing (equivalent to 0.0029 lb/MMBtu with duct firing and 0.0025 lb/MMBtu without duct firing)

Step 2 – Eliminate Technologically Infeasible Options

As discussed above, solar, wind and other renewable energy alternatives are not considered technologically feasible for this application.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

No control technology other than use of clean natural gas fuel has been identified for this application. The proposed PM_{10} emission limits are lower on a lb/MMBtu basis than any of the recent BACT determinations shown in Table 3.1D-4.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

No control technology other than use of clean natural gas fuel has been identified for this application.

Step 5 – Determine BACT/Present Conclusions

Based upon the results of this analysis, the use of natural gas as the primary fuel source constitutes BACT for $PM_{10}/PM_{2.5}$ emissions from combustion gas turbines. Through the use of natural gas, the turbines are expected to be able to meet the proposed emission limits of 10 lb/hr with duct firing and 8 lb/hr without duct firing.

3.1.3 BACT for the Combined-Cycle CTGs: Startup/Shutdown

Startup and shutdown periods are a normal part of the operation of combined-cycle power plants such as SEP. BACT must also be applied during the startup and shutdown periods of gas turbine operation. The BACT limits discussed in the previous section apply to steady-state operation, when the turbines have reached stable operations and the emission control systems are fully operational.

3.1.3.1 NOx EMISSIONS

Step 1 – Identify All Possible Control Technologies

The following technologies for control of NOx during startups and shutdowns have been identified:

- A Selective Catalytic Reduction (SCR) system capable of continuously complying with a limit of 2.0 ppmc (1-hour average);
- Fast-start technologies; and
- Operating practices to minimize the duration of startup and shutdown.

The SEP gas turbine will be controlled by a dry low-NOx combustor and SCR. The SCR system will operate at all times that the stack temperature is in the proper operating range.

Step 2 – Eliminate Technologically Infeasible Options

During gas turbine startup, there are equipment and process requirements that must be met in sequential order to protect the equipment.

For all turbine technologies, incomplete combustion at low loads results in higher CO and VOC emission rates. Furthermore, the post-combustion controls that are used to achieve additional emissions reductions (SCR and oxidation catalyst) require that specific exhaust temperature ranges be reached to be fully effective. The use of SCR to control NOx is not technically feasible during the initial stages of startup, when the surface of the SCR catalyst is below the manufacturer’s recommended operating range. When catalyst surface temperatures are low, ammonia will not react completely with the NOx, resulting in excess NOx emissions or excess ammonia slip or both. The oxidation catalyst is not effective at controlling CO emissions when exhaust temperature is below the optimal temperature range. Therefore, exhaust gas controls used to achieve BACT for normal operations are not feasible control techniques during startups and shutdowns.

This “top-down” BACT analysis will consider the following NOx emission limitations:

- Operating practices to minimize emissions during startup and shutdown; and
- Design features to minimize the duration of startup and shutdown.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Operating Practices to Minimize Emissions during Startup and Shutdown

There are basic principles of operation, or Best Management Practices, that minimize emissions during startups and shutdowns. These Best Management Practices are outlined below.

- During a startup, bring the gas turbine to the minimum load necessary to achieve compliance with the applicable NOx and CO emission limits as quickly as possible, consistent with the equipment manufacturers’ recommendations and safe operating practices.
- During a startup, initiate ammonia injection to the SCR system as soon as the SCR catalyst temperature and ammonia vaporization system have reached their minimum operating temperatures.
- During a shutdown, once the turbine reaches a load that is below the minimum load necessary to maintain compliance with the applicable NOx and CO emission limits, reduce the gas turbine load to zero as quickly as possible, consistent with the equipment manufacturers’ recommendations and safe operating practices.

- During a shutdown, maintain ammonia injection to the SCR system as long as the SCR catalyst temperature and ammonia vaporization system remain above their minimum operating temperatures.

A key underlying consideration of these Best Management Practices is the overall safety of the plant staff by promoting operation within the limitations of the equipment and systems, and allowing for operator judgment and response times to respond to alarms and trips during a startup or shutdown sequence.

Design Features to Minimize the Duration of Startup and Shutdown

An additional technique to reduce startup emissions is to minimize the amount of time the gas turbine spends in startup. Startup times for conventional combined-cycle gas turbines are generally driven by the need for long gas turbine holds at low loads as the HRSG and steam turbine come up to operating temperature and pressure. The use of Rapid Response startup technology eliminates the long hold times by decoupling the gas turbine from the steam cycle startup, allowing the gas turbine to be brought up to minimum emissions-compliant load quickly without the need for low-load holds. This reduces the typical startup times for the gas turbine from up to 3 hours for a cold start to under 1 hour.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

Utilizing best operating practices to minimize emissions during startups and shutdowns has no adverse environmental or energy impacts, nor does it require additional capital expenditure.

The approach of reducing startup/shutdown duration has no adverse environmental or energy impacts, and the use of Rapid Response startup technology minimizes startup/shutdown duration.

Step 5 - Determine BACT/Present Conclusions

BACT for NOx during startups/shutdowns is the use of operating systems/practices that reduce the duration of startups and shutdowns to the greatest extent feasible, and the use of operational techniques to initiate ammonia injection as soon as possible during a startup. Therefore, BACT is determined to be the use of combined-cycle gas turbine technology with Rapid Response technology and the application of operating systems/practices that minimize startup and shutdown durations, in combination with the use of operational techniques to initiate ammonia injection as soon as possible during a startup.

3.1.3.2 VOC EMISSIONS

Step 1 – Identify All Possible Control Technologies

The VOC control technologies under consideration for startups and shutdowns are ranked as follows:

- Operating practices to minimize the duration of startup and shutdown.

Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only proposed control technology is operating practices to minimize the duration of startups and shutdowns.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

VOC emissions during startup and shutdown are minimized by minimizing the duration of startup and shutdown.

Step 5 – Determine BACT/Present Conclusions

BACT for VOC during startups/shutdowns is the use of combined-cycle gas turbine technology and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

3.1.3.3 SULFUR OXIDE EMISSIONS

Step 1 – Identify All Possible Control Technologies

The SOx control technologies under consideration for startups and shutdowns are ranked as follows:

- Use of natural gas as a fuel; and
- Operating practices to minimize the duration of startup and shutdown.

Step 2 – Eliminate Technologically Infeasible Options

None of the proposed alternatives is infeasible for this application.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

Ranking for the control technologies is as indicated in Step 1.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

SOx emissions during startup and shutdown are minimized by use of natural gas as a fuel, and minimizing duration of startup and shutdown.

Step 5 – Determine BACT/Present Conclusions

BACT for SOx during startups/shutdowns is the use of natural gas as a fuel, and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible.

3.1.3.4 PM/PM_{10}/$PM_{2.5}$ EMISSIONS

Step 1 – Identify All Possible Control Technologies

The analysis for particulate is identical to the analysis for SOx.

Step 2 – Eliminate Technologically Infeasible Options

The analysis for particulate is identical to the analysis for SOx.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The analysis for particulate is identical to the analysis for SOx.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

The analysis for particulate is identical to the analysis for SOx.

Step 5 – Determine BACT/Present Conclusions

BACT for particulate during startups/shutdowns is the use of natural gas as a fuel, and operating practices that reduce the duration of startups and shutdowns to the greatest extent feasible

3.1.3.5 SUMMARY

Proposed BACT determinations for the SEP gas turbines are summarized in Table 3.1D-5.

Table 3.1D-5
Proposed BACT Determinations for SEP Gas Turbine

Pollutant	Proposed BACT Determination
Nitrogen Oxides	Dry low-NOx combustion controls and SCR system, 2.0 ppmc[a], 1-hour average, with exemptions for startup/shutdown conditions
Sulfur Dioxide	Natural gas fuel (sulfur content not to exceed 0.5 grain/100 scf)
VOC	Good combustion practices, 2.0 ppmc with duct firing, 1.0 ppmc without duct firing, 1-hour average
$PM_{10}/PM_{2.5}$	Natural gas fuel, 10 lbs/hr with duct firing, 8 lb/hr without duct firing
GHGs	GE 7HA.02 combined-cycle gas turbine technology, good combustion practices
Startup/Shutdown	Best operating practices to minimize startup/shutdown times and emissions

Note:
a. ppmc: parts per million by volume dry, corrected to 15% O_2.

3.1.4 BACT for the Cooling System

Step 1 – Identify All Possible Control Technologies

The first step in a top-down analysis is to identify, for the emissions unit and pollutant in question, all available control options. Available control options are those air pollution control technologies or techniques, including alternate basic equipment or processes, with a practical potential for application to the emissions unit in question. The control alternatives should include not only existing controls for the source category in question, but also, through technology transfer, controls applied to similar source categories and gas streams.

The emissions source for which BACT is being considered is a wet cooling tower with high efficiency drift eliminators.

Potential control technologies were identified by searching the following sources for entries pertaining to cooling towers:

- SCAQMD BACT Guidelines;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT Guidelines;
- USEPA RACT/BACT/LAER Clearinghouse;
- Other districts' and states' BACT Guidelines; and
- BACT/LAER requirements in New Source Review permits issued by AQMD or other agencies.

BACT determinations from the SCAQMD, SJVAPCD, BAAQMD, and USEPA are summarized in Table 3.1D-6.

Table 3.1D-6
Summary of PM_{10} BACT Clearinghouse Guidelines

Permitting Agency	Guideline	Operation	PM_{10} BACT for Cooling Towers
SCAQMD	None	N/A	N/A

SJVAPCD	§8.3.10	Induced Draft Evaporative Cooling Tower	Cellular Type Drift Eliminator
BAAQMD	None	N/A	N/A
USEPA	RBLC Listings	Industrial Cooling Towers	Drift Eliminators 0.0005% Drift Rate

Table 3.1D-7 summarizes information on wet cooling towers of the type proposed for use at SEP that have recently been approved by the California Energy Commission (CEC) through the Application for Certification (AFC) process; these controlled emission rates were approved by the indicated permitting authority. Recent BACT determinations for similarly sized cooling towers from the EPA RBLC listings are summarized in Table 3.1D-8.

Table 3.1D-7

PM_{10} Emission Rates for Wet Cooling Towers in CEC Proceedings

Permitting Agency	Project	Permit Required?	Permit Date	Circulating Water Flow Rate	Drift Rate Limit
SCAQMD	Inland Empire Energy Center	yes	2005 (amendment)	90,000 gpm (each of two)	0.0005%
	Watson Cogeneration	yes	2011	18,600 gpm (two new cells only)	0.001%
SJVAPCD	NCPA Lodi Energy Center	yes	2010	69,000 gpm	0.0005%
	Walnut Energy Center	yes	2004	68,500 gpm	0.0005%
BAAQMD	Metcalf Energy Center	yes	2001	133,378 gpm	0.0005%

Table 3.1D-8

PM_{10} BACT Determinations for Wet Cooling Towers From RBLC Database

Project	Permit # (Date)	Circulating Water Flow Rate	Drift Rate Limit
NRG Texas Power LLC, Bertron Electric Generating Station	TX-0714 (December 2014)	not specified	0.0005%
Holland Board of Public Works combined cycle power plant	MI-0412 (December 2013)	not specified	0.0005%
St. Joseph Energy Center	IN-0158 (December 2012)	170,000 gpm	0.0005%
Enertergy LA LLC, Ninemile Point Electric Generating Plant	LA-0254 (August 2011)	1215,847 gpm	0.0005%

BACT must be at least as stringent as what has been achieved in practice (AIP) for a category or class of source. Additionally, USEPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust stream controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes. In order to be considered, the candidate control technology must be technologically feasible for the application being reviewed. In order to be required as BACT, the candidate technology must be cost effective, considering energy, environmental, economic, and other costs.

Three possible alternate basic technologies were identified from background technical materials prepared during the rulemaking of USEPA's National Pollutant Discharge Elimination System (NPDES).[10] The NPDES regulation establishes national technology-based performance requirements applicable to the location, design, construction, and capacity of cooling water intake structures at new facilities using once-through cooling. During the rulemaking process, USEPA also evaluated alternatives to once-through cooling, including recirculating wet cooling systems, dry cooling systems, and hybrid cooling systems.

Recirculating Wet Cooling Tower with High Efficiency Drift Eliminator – In conventional closed-cycle recirculating wet cooling towers, cooling water that has been used to cool the condensers is pumped to the top of a recirculating cooling tower; as the heated water falls, it cools through an evaporative process and warm, moist air rises out of the tower, often creating a vapor plume. Approximately 80% of the heat transfer (cooling) occurs due to evaporation, and 20% of the heat transfer occurs due to convection.[11] Therefore, wet cooling towers are most effective in areas of low relative humidity.

Dry Cooling Tower – Dry cooling systems (towers) use either a natural or a mechanical air draft to transfer heat from the condenser tubes to air. Their effectiveness is independent of relative humidity and purely a function of the ambient (dry-bulb) temperature. Therefore, dry cooling towers are most effective in areas of low ambient temperature.

Plume-Abated Wet Cooling – There are several types of hybrid wet/dry cooling towers. One type is essentially a wet cooling tower with an additional dry section installed on top that reduces vapor plumes by heating the wet air from the wet section. This is done to reduce or eliminate the visible condensation plume.

Spray-Enhanced Dry Cooling – The second type of hybrid system is essentially a dry cooling tower that enhances heat transfer in the condenser tubes by spraying water on the outside of the tubes.

Hybrid Wet/Dry Cooling – A third type of hybrid system is a system designed for water conservation, which is usually a primarily dry system with a small wet capacity to provide additional cooling during the hottest periods of the year to mitigate hot-day capacity loses associated with all-dry systems.[12] However, a hybrid wet/dry system can be designed to different wet/dry proportions depending upon ambient conditions and on the amount of water conservation desired.

Once-through Cooling – Once-through cooling systems eliminate the cooling tower entirely by drawing cooling water from a water source (such as a river or the ocean), using the water to cool the condensers, and then discharging the heated water, usually back to the original water source.

Step 2 – Eliminate Technologically Infeasible Options

The next step in the top-down BACT procedure is to eliminate technologically infeasible options.

Recirculating Wet Cooling Tower – As shown in Table 3.1D-7 and Table 3.1D-8, the proposed technology, recirculating wet cooling towers equipped with high-efficiency (0.0005%) drift eliminators, has been achieved in practice.

[10] EPA, "Regulations Addressing Cooling Water Intake Structures for New Facilities," 66 FR 24, December 18, 2001.

[11] Hensley, John C., ed. 2006. *Cooling Tower Fundamentals*. SPX Cooling Technologies, Inc., 2006.

[12] EPRI. *Comparison of Alternate Cooling Technologies for U.S. Power Plants: Economic, Environmental, and Other Tradeoffs*, September 9, 2004.

Dry Cooling – USEPA has adopted standards for new facilities that draw cooling water from waters of the U.S.[13] The regulation established the best technology available for minimizing adverse environmental impacts associated with the use of cooling water intake structures.

As part of the rulemaking process, USEPA considered the technical issues, cost, and environmental impacts associated with replacing once-through cooling with recirculating cooling towers and dry cooling. USEPA rejected dry cooling as the best replacement technology due to all three of these factors. For the purposes of this BACT analysis, the technical issues are evaluated in this step. The environmental impacts and cost considerations of dry cooling are evaluated in the following step.

The three main technical issues associated with dry cooling towers are increased steam turbine backpressure, increased space needs, and increased downwash effects. Dry cooling results in increased steam turbine backpressure because of its inability to condense steam at 100% capacity on very hot days. For safety reasons, steam turbines are designed so that a plant shutdown will be triggered if backpressure limits are exceeded. The thermal inefficiency of dry cooling has caused turbine backpressure limits to be exceeded at existing plants, which in turn has triggered plant shutdowns. Because the potential for increased steam turbine backpressure is most severe when the ambient temperature is highest, the resulting plant shutdowns occur when electricity demand is at its peak.[14]

Another potential issue associated with dry cooling towers is space. Because dry cooling systems rely only on convective and radiant heat transfer, they require a significantly larger footprint compared to wet cooling towers. While the SEP project site is large, the usable area is highly space-constrained because of the project's proximity to the Blythe Airport. Therefore, it would be extremely difficult to install the required dry cooling capacity within the available space.

A third potential issue associated with dry cooling towers is increased downwash effects. When the wind blows over large structures, a wake effect on the leeward side of the building can pull the air down toward the ground, a meteorological condition known as building wake downwash. Because structures for dry cooling are much larger than comparable wet cooling towers, the downwash effect is potentially greater. Increased downwash can result in higher ambient concentrations from nearby emissions sources. This potential problem would be more acute at SEP, where the gas turbine stack height has been minimized to reduce potential impacts to aircraft.

For the purposes of this analysis, dry cooling was not eliminated as a potential BACT option due to increased turbine backpressure, space constraints, or downwash effects. It is likely that the space issue alone would prohibit the use of dry cooling at SEP; however, for purposes of this analysis, the technology has been presumed to be feasible. As shown in the next steps, the environmental and energy impacts of dry cooling preclude its selection as the appropriate BACT option.

Plume-Abated Wet Cooling Tower – Plume-abated cooling towers employ both a wet section and dry section and reduce or eliminate the visible plumes associated with wet cooling towers. In general, a plume-abated cooling tower is used only where a visible plume presents a threat to public safety by its interference with major infrastructure or in cases where the plume will block prominent landscape features or scenic coastal areas.[15]

Plume-abated wet cooling towers offer only insignificant changes in PM, $PM_{10,}$ and $PM_{2.5}$ emissions compared to wet cooling towers. After the warm, moist air passes through the drift eliminators of the wet section, it is mixed with warm dry air that passed through the dry section. This step speeds

[13] EPA 2001

[14] EPA 2001, p. 65283.

[15] EPRI 2004, pp. 5-2 – 5-3.

the evaporation that would normally occur after the plume was released. While most remaining liquid drift may be eliminated within the dry section of the cooling tower via evaporation, the particulate nuclei are not reduced or eliminated by any physical process and are exhausted through the top of the cooling tower.

Even though this option does not decrease PM emissions from the cooling tower, it also has not been deemed technologically infeasible as appropriate BACT for the SEP cooling tower. Thus, the environmental and economic impacts of this option are discussed in the following steps.

Spray-Enhanced Dry Cooling – A spray-enhanced hybrid cooling tower works essentially as a dry cooling tower that enhances heat transfer in the condenser tubes by spraying water on the outside of the tubes. The addition of the evaporating water spray can help alleviate the technical issues associated with dry cooling. Increased cooling decreases the likelihood of turbine backpressure events and may allow for fewer, more efficient dry cooling cells to be installed, thus shrinking the plant footprint required for the cooling tower. Therefore, this BACT option has not been deemed technologically infeasible; however, the same technical issues associated with dry cooling would render spray-enhanced dry cooling infeasible pursuant to a detailed engineering analysis.

Hybrid Wet/Dry Cooling – A hybrid wet/dry cooling system designed for water conservation uses dry cooling technology for most cooling needs, but employs a wet cooling system during peak load periods of high temperature to mitigate the losses in steam cycle capacity and plant efficiency associated with 100% dry cooling systems. To significantly reduce PM emissions over a full wet cooling tower design, the dry cooling portion of this type of hybrid system would need to be sized to handle the majority of the plant-cooling load. As a result, this design would be expected to have the same technical issues as those attributable to a 100% dry cooling design.

Once-through Cooling – Once-through cooling involves the water withdrawn from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters. In general, once-through cooling is technologically feasible only when a large surface water body exists in immediate proximity to the power plant. Since this situation does not exist for the SEP project, once-through cooling has been deemed a technologically infeasible BACT option and will not be further evaluated.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control technology options are ranked by control effectiveness in Table 3.1D-9. Once-through cooling was eliminated in Step 2.

Table 3.1D-9
Cooling Technologies Ranked by PM_{10} Control Effectiveness

Cooling Technology	Comments
Dry cooling	No PM_{10} emissions
Spray-enhanced dry cooling	Minimal PM_{10} emissions associated with evaporation of water spray
Hybrid wet/dry cooling	PM_{10} emissions depend upon relative size of wet and dry portions of hybrid system
Plume-abated wet cooling/ Wet cooling tower with high efficiency drift eliminators	No difference in PM_{10} emissions

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

This step evaluates any source-specific environmental, energy, or economic impacts that demonstrate that the alternatives shown in Table 3.1D-9 are inappropriate as BACT.

Aside from the proposed BACT technology of a wet cooling tower with high-efficiency drift eliminators, the remaining technologies employ full or partial dry cooling in various ways.

Dry Cooling – In evaluating once-through cooling replacement technologies, USEPA determined that dry cooling costs are sufficient to pose a barrier to entry to the marketplace for some projected new facilities. Additionally, dry cooling was determined to have a detrimental effect on electricity production by reducing energy efficiency of steam turbines, also known as the “energy penalty.”

The energy penalty results from the power producer utilizing more energy than would otherwise be required with recirculating wet cooling to produce the same amount of power. Dry cooling produces increased parasitic loads from larger recirculation pumps and fans required by dry cooling. Additionally, because the degree of cooling of the water affects the efficiency of the steam turbine, dry cooling can result in raising the overall heat rate of the power plant by increasing the backpressure to the steam turbine. These effects are discussed in further detail in Chapter 3 of the Technical Development Document for the 2001 NPDES Regulation. [16]

As a result of the analysis for the NPDES rule, USEPA concluded that energy penalties associated with dry cooling tower systems pose a significant feasibility problem in some climates. It follows that the energy penalty would be the highest in climates that exhibit (1) high ambient (dry bulb) temperatures, and (2) low relative humidity. As the ambient temperature increases, the convection rate between the hot water and the hot ambient air decreases in a dry cooling tower. Also, as relative humidity decreases, the rate of evaporation (which is responsible for 80% of the cooling) increases in a wet cooling tower. The opportunity cost of not using the most efficient cooling technology in a particular climate adds to the energy penalty. For the SEP project, it is noted that the energy penalty would be highest at the time of peak demand, i.e., summer heat episodes when the plant would theoretically be operating at its peak load.

In Chapter 3 of the USEPA’s Technical Development Document, the mean annual performance penalty of a full dry cooling system relative to recirculating wet cooling tower was estimated in four separate US climates—Boston, Massachusetts; Jacksonville, Florida; Chicago, Illinois; and Seattle,

[16] EPA 2001, Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities, EPA-821-R-01-036, November 2001.

Washington. Of these climates, Jacksonville would most closely resemble the climate of Blythe due to its having the highest ambient temperatures.

The Technical Development Document calculated the total energy penalties of dry cooling by summing the individual penalties of turbine efficiency losses with increased energy usage by pumps and fans. In Table 3-15 of the Technical Development Document, the turbine efficiency losses of a dry cooling tower compared to a wet cooling tower were calculated to be 1.96% of the total electrical output of a combined cycle power plant operating in Jacksonville. This represents the annual average penalty experienced while the plant's steam turbine is operating at 67% of its maximum design load. In Table 3-20 of the Technical Development Document, the energy penalties of increased water pumping and fan usage were calculated to be 0.42% of the total electrical output of a combined cycle power plant (independent of location and turbine load). Therefore, the total energy penalty associated with dry cooling at a Jacksonville combined cycle power plant equals 2.38% of total electrical output.

Because of energy penalties, power plants using dry cooling burn more fuel and produce more air emissions per kilowatt-hour of energy produced. It should also be noted that the actual effect of the performance penalty would be to reduce SEP's peak production capacity on days when demand is highest, necessitating dispatch of other plants with even higher emissions.

The cost for a dry cooling system is also significantly higher than the cost for a wet cooling tower. The cooling alternative study prepared for the CEC in 2002 estimated a capital cost of $44.7 million for a new 500 MW power plant with a 170 MW steam cycle located in the California desert. [17] This compares with a comparable wet cooling system capital cost that ranged from $3.7 to $4.1 million. [18]

The prohibitive capital cost and energy penalty, along with the siting issues discussed earlier (size and potential downwash effects) eliminate dry cooling from consideration as BACT for this project.

<u>Spray Enhanced Dry Cooling</u> – As discussed in the previous step, spray-enhanced dry cooling causes lower turbine efficiency losses compared to a full dry cooling system. The additional pumps for water spray would increase fan and pump losses by a small degree. The effectiveness of the water spray in recovering a portion of the energy penalties was evaluated in an EPRI study. [19] The report conducted empirical testing on a single dry cooling cell located at the Crockett Cogeneration Co. located in Crockett, California. The report concluded that during hot and dry periods (over 100° F), spray enhancement could reduce the temperature of the airflow through the cooling tower by as much as 75% of the wet bulb depression, or about 18° F. The corresponding reduction of steam turbine backpressure was determined using a curve of ambient temperature versus backpressure, and the corresponding increase in plant efficiency was determined using a curve of turbine backpressure versus electrical output. The overall conclusion of the study was that under certain conditions, approximately half of the turbine's lost output could be restored. [20]

The capital cost for spray-enhanced dry cooling would be higher than the capital cost of dry cooling alone, the PM_{10} emissions would be higher, and the siting issues would be the same. Therefore, spray-enhanced dry cooling is also eliminated as BACT for this project.

<u>Hybrid Wet/Dry Cooling</u> – The degree of PM_{10} emissions reduction achievable by a hybrid wet/dry cooling system depends on how much of the cooling load each portion of the system is designed to

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[17] EPRI 2002, Figure 5-11.

[18] EPRI 2002, Table 5-18.

[19] EPRI, "Spray Enhancement of Dry Air-Cooled Condensers," prepared by the Electric Power Research Institute for the California Energy Commission, September 2003.

[20] Ibid, p. 7-8.

achieve. A system designed to carry most of the cooling load in the dry system would have lower water use and PM_{10} emissions but would have a higher capital cost as well the siting issues (size and potential downwash effects) associated with a full dry cooling system. A system designed to carry more of the cooling load in the wet system would not attain the degree of PM_{10} emission reduction achievable with a system designed for a higher dry cooling load, but would also be significantly more expensive and would have a higher energy demand than a wet cooling tower. Therefore, a hybrid wet/dry cooling system is also eliminated as BACT for this project.

Plume-Abated Wet Cooling – A plume-abated wet cooling tower is no more effective in eliminating drift and particulate matter compared to a wet cooling tower. For this reason, a plume abated cooling tower is ranked lower than a wet cooling tower for PM_{10} BACT purposes. However, the addition of a plume abatement section would require the tower to be taller. In addition, the initial capital cost of a plume-abated tower was found to be as much as 2 to 3 times higher than the cost of a conventional wet cooling tower.[21] Visible vapor plumes are most problematic under very cold and/or humid conditions, and these conditions rarely if ever occur at the plant site. Since this technology is no more effective than the proposed technology in reducing PM emissions, is not needed for safety reasons, and has higher costs and potentially higher environmental impacts due to its taller height, it is eliminated from consideration and no further analysis is necessary.

Step 5 – Select BACT

Based upon the above information, BACT is use of a high-efficiency drift eliminator with a drift rate of 0.0005% or less. The proposed cooling tower complies with this BACT level.

3.1.5 BACT for the Emergency Engine

3.1.5.1 Normal Operations

The emission unit for which BACT is being considered is a nominal 238 HP Tier 3 Clarke Diesel engine driving a fire pump. Potential control levels were identified by searching the following sources for BACT determinations pertaining to emergency Diesel fire pump engines:

- VCAPCD BACT Guidance;
- SCAQMD BACT Guidelines;
- SJVAPCD BACT Clearinghouse;
- BAAQMD BACT Guidelines; and
- EPA Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emission Rate (LAER) Clearinghouse.

3.1.5.2 NOx EMISSIONS

Step 1 – Identify All Possible Control Technologies

Listed below are the technologies for control of NOx that were identified as a result of review of sources of BACT determinations.

- Combustion process modifications. Design features that minimize emissions include electronic fuel/air ratio and timing controllers, pre-chamber ignition, and intercoolers. These design features form the basis for EPA's Tier emission standards and are therefore considered the baseline case for purposes of the BACT analysis.

[21] TetraTech, "California's Coastal Power Plants: Alternative Cooling System Analysis," prepared for California Ocean Protection Council, February 2008. Chapter 4, Section 3.5.2.

- Selective Catalytic Reduction (SCR): This is an add-on control technology that reduces NOx emissions by reaction with ammonia in the presence of a catalyst.
- Non-selective Catalytic Reduction (NSCR): Similar to automobile catalytic converters, this is an add-on control technology that reduces NOx emissions by reacting NOx with CO and hydrocarbons to form CO_2, N_2, and H_2O. This catalyst requires a fuel-rich exhaust to work and is therefore not applicable to Diesel engines, which operate in a lean-burn mode.

Step 2 – Eliminate Technologically Infeasible Options

As discussed in Step 1, NSCR is not technologically feasible for a lean-burn IC engine. It was therefore eliminated from consideration for BACT for this application.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The most recent NOx BACT listings for Diesel emergency fire pump engines in this size range are summarized in Table 3.1D-10. The most stringent NOx limit in these recent BACT determinations is a 3.0 gm/hp-hr limit, based on compliance with applicable EPA Tier 3 standards and the federal NSPS Subpart IIII.

Table 3.1D-10
Recent NOx BACT Determinations for Emergency Compression-Ignition Engines

Facility	District	NOx Limit[a,b]	Control Method Used	Date Permit Issued	Source
Power Systems	SCAQMD	3.9	Engine Designed to meet EPA Tier 2	11/6/2003	SCAQMD BACT (A/N 417691)
General Guidelines	SCAQMD	3.0 (Tier 3 limit)	Engine Designed to meet EPA Tier 3	10/3/2008[c]	SCAQMD guidelines for non-major facilities
BACT Handbook	BAAQMD	3.0 (CARB ATCM)	Engine Designed to meet EPA Tier 3	12/22/2010	BAAQMD BACT guideline 96.1.3
BACT Guidelines	SJVAPCD	6.9	Engine Design	6/30/2001	SJVAPCD BACT Guideline 3.1.4
Moundsville Power LLC	West Virginia	3.0	251 hp engine Engine Design	1/6/2015	EPA RBL Clearinghouse
Energy Answers Arecibo LLC	Puerto Rico	3.0[d] (Tier 3 limit)	Engine Design	4/10/2014	EPA RBL Clearinghouse
ARB ATCM		3.0	Engine Design	5/19/2011	H&SC 93115.6(a)(4), Table 2
Federal NSPS	Subpart IIII	3.0	Engine Designed to meet EPA Tier 3		40 CFR 60.4205, Table 4 to Subpart IIII

Notes:

a. All concentrations expressed as grams per horsepower-hour (g/hp-hr).

b. For Tier 2 and Tier 3 limits, values are for NOx + NMHC.

c. Revision date for guideline.

d. NOx limit is 2.85 g/hp-hr and VOC limit is 0.15 g/hp-hr.

Step 4 – Evaluate the Most Effective Control Technology Considering Environmental, Energy, and Cost Impacts

The most stringent limit in Table 3.1D-10 is the EPA Tier 3 limit. Engine manufacturers are using a combination of techniques, including incorporation of exhaust control techniques as part of the basic engine, to achieve this limit. For this reason, an engine capable of achieving EPA Tier 3 limits is the most effective control technology considering environmental, energy, and cost impacts.

Step 5 – Determine BACT/Present Conclusions

BACT must be at least as stringent as the most stringent level achieved in practice, federal NSPS, or district prohibitory rule. Based upon the results of this analysis, the NOx emission rate of 3.0 g/hp-hr required to meet EPA Tier 3 requirements is BACT. Although the fire pump engine at the Energy Answers Arecibo plant is shown as having a lower NOx emission rate, this emission rate is based on a manufacturer certification rate and does not reflect actual test data for the engine. Therefore, BACT for NOx for this application is any technology capable of achieving the Tier 3 NSPS limit.

The engine selected for this project is equipped with advanced combustion controls and is certified to meet Tier 3 standards with a NOx emission rate of 2.56 gm/hp-hr. Therefore the engine complies with BACT for NOx.

Appendix 3.1E
Modeling Protocol and Related Correspondence

Air Dispersion Modeling and Health Risk Assessment Protocol

Kananaskis Energy Project Blythe, California

Submitted to:

Mojave Desert Air Quality Management District (for an Application for an Authority to Construct/ Determination of Compliance)

California Energy Commission (for an Application for Certification)

prepared for:

Altagas Kananaskis Energy Project

September 2014

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95811
(916) 444-6666

Air Dispersion Modeling and Health Risk Assessment Protocol
Kananaskis Energy Project
Blythe, California

Submitted to:

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Air Dispersion Modeling and Health Risk Assessment Protocol
Kananaskis Energy Project

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1. INTRODUCTION

This protocol describes the modeling procedures that will be used to determine the ambient air impacts from the Kananaskis Energy Project (also referred to herein as "KEP" or "the Project"). These procedures will be used in the ambient air quality impact assessment and screening health risk assessment that will be submitted to the Mojave Desert Air Quality Management District (MDAQMD, or District) as part of an application for Final Determination of Compliance and Authority to Construct, and to the California Energy Commission as part of an Application for Certification.

2. FACILITY DESCRIPTION AND SOURCE INFORMATION

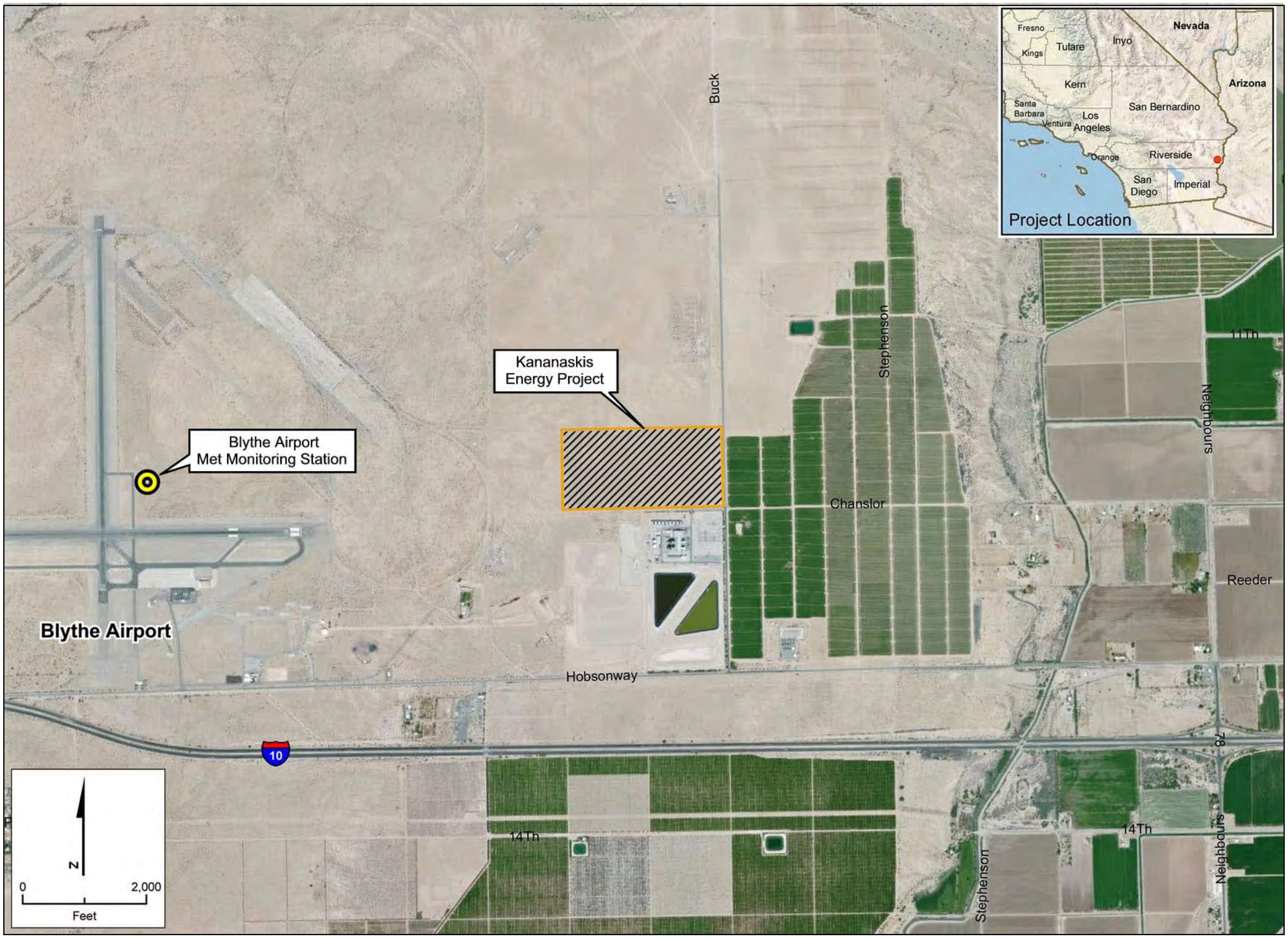
The Kananaskis Energy Project (KEP or Project) will consist of six natural gas-fired General Electric LMS100 PB simple-cycle combustion turbines, one natural gas-fired LM6000 PF SPRINT simple-cycle combustion turbine, a water treatment and storage system, a storm water retention pond, an aqueous ammonia storage tank, and ancillary facilities. The Project will utilize a hybrid partial dry cooling system to minimize water use. KEP will be located on a 76-acre site in an unincorporated area of Riverside County, near the City of Blythe. The property is located adjacent to the existing, operational Blythe Energy Project[1] and the site of the licensed Blythe Energy Project Phase II.[2] Figure 1 shows the general location of the Project.

The proposed new gas turbine units will be equipped with Best Available Control Technology (BACT). BACT will include dry low-NOx (DLE) combustion technology for the gas turbines, selective catalytic reduction (SCR), oxidation catalysts, and use of clean-burning natural gas fuel. The operating schedule for the new gas turbine units will vary and may range from no operation during the winter months to potentially 24 hours of operation per day during the summer months. The modeling analysis will be performed for the worst-case (maximum expected equipment operation) operating hour, operating day, and operating year. The modeling analysis will include a complete description of the new equipment, including the worst-case hourly, daily, and annual operating schedules used for the analysis.

The Proposed Project is also expected to trigger Prevention of Significant Deterioration (PSD) review for criteria pollutants and greenhouse gases. The MDAQMD is in the process of obtaining delegation from EPA to implement PSD permitting for criteria air pollutants and GHG. Depending on the timing of this delegation, it may be necessary to file a separate PSD permit application with EPA Region 9.

[1] 99-AFC-8C
[2] 02-AFC-1C

Figure 1
Location of the Proposed Project



3. DISPERSION MODELING PROCEDURES

The air quality modeling analysis will follow the March 2009 U.S. Environmental Protection Agency (USEPA) AERMOD Implementation Guide (USEPA, 2009) and USEPA's "Guideline on Air Quality Models" (USEPA, 2005).

3.1 AERMOD Modeling

The following USEPA air dispersion models are proposed for use to quantify pollutant impacts on the surrounding environment based on the emission sources' operating parameters and their locations:

- American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (Version 14134);

- Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, Version 04274); and

- SCREEN3 (Version 96043).

The main air dispersion modeling will be conducted with the latest version of AERMOD, USEPA's preferred/recommended dispersion model for new source review and PSD air quality impact assessments. AERMOD can account for building downwash effects on dispersing plumes. Stack locations and heights and building locations and dimensions will be input to BPIP-PRIME. The first part of BPIP-PRIME determines and reports on whether a stack is being subjected to wake effects from a structure or structures; the second part calculates direction-specific building dimensions for each structure, which are used by AERMOD to evaluate wake effects. The BPIP-PRIME output is formatted for use in AERMOD input files.

AERMOD requires hourly meteorological data consisting of wind direction and speed (with reference height), temperature (with reference height), Monin-Obukhov length, surface roughness length, heights of the mechanically and convectively generated boundary layers, surface friction velocity, convective velocity scale, and vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer.

Standard AERMOD control parameters will be used, including stack tip downwash, non-screening mode, non-flat terrain, and sequential meteorological data check. The stack-tip downwash algorithm will be used to adjust the effective stack height downward following the methods of Briggs (1972) for cases where the stack exit velocity is less than 1.5 times the wind speed at stack top. The rural option will be used by not invoking the URBANOPT option.[3]

If more detailed evaluation of impacts at receptors in terrain above stack-top height is required, the screening version of the USEPA guideline Complex Terrain Dispersion Model PLUS (CTDMPLUS)—Complex Terrain Screening Model (CTSCREEN)—would be used. The CTSCREEN model is discussed in more detail in Appendix A.

3.1.1 Ambient Ratio Method and Ozone Limiting Method

Annual nitrogen dioxide (NO_2) concentrations will be calculated using the Ambient Ratio Method (ARM), originally adopted in Supplement C to the Guideline on Air Quality Models (USEPA, 1995) with a revision issued by EPA in March 2011.[4] The Guideline allows a nationwide default of 75% for the conversion of nitric oxide (NO) to NO_2 on an annual basis[5] and the calculation of NO_2/NOx (nitrogen oxide) ratios.

If NO_2 concentrations need to be examined in more detail, the Ozone Limiting Method (OLM) (Cole and Summerhays, 1979), implemented through the "OLMGROUP ALL" option in AERMOD (USEPA, 2011a), will be used. AERMOD OLM will be used to calculate the NO_2 concentration based on the OLM method and hourly ozone data. Contemporaneous hourly ozone data collected at the nearby Blythe monitoring station will be used in conjunction with OLM to calculate hourly NO_2 concentrations from modeled hourly NOx concentrations.

Part of the NOx in the gas turbine exhaust is converted to NO_2 during and immediately after combustion. The remainder of the NOx emissions is assumed to be in the form of NO. For the new gas turbines, we will use the same NO_2/NOx ratios for the OLM analysis (discussed in more detail below) as those accepted by the SDAPCD for permitting of the Apex Pio Pico and NRG Carlsbad Energy Center projects (13% during normal operating hours, 24% during startup/shutdown periods, and 24% during commissioning tests when SCR is not fully operational).[6]

As the exhaust leaves the stack and mixes with the ambient air, the NO reacts with ambient ozone (O_3) to form NO_2 and molecular oxygen (O_2). The OLM assumes that at any given receptor location, the amount of NO that is converted to NO_2 by this oxidation reaction is proportional to the ambient O_3 concentration. If the O_3 concentration is less than the NO

[3] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the project site.

[4] "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS", Office of Air Quality Planning and Standards, Research Triangle Park, NC, March 1, 2011.

[5] USEPA, "New NO_2 Modeling Guidance," August 12, 2014. Available at *http://www.epa.gov/ttn/scram/webinar/AERMOD_14134-NO2_Memo/20140812-Webinar_Slides.pdf.*

[6] If the final project design includes a Diesel emergency firepump engine and/or a Diesel emergency generator, we will use a NO_2/NOx ratio discussed in Appendix B.

concentration, the amount of NO_2 formed by this reaction is limited. However, if the O_3 concentration is greater than or equal to the NO concentration, all of the NO is assumed to be converted to NO_2.

A detailed discussion of OLM modeling and how OLM modeling results and monitored background NO_2 will be combined is provided in Sections 3.6.3 and 3.6.4.

3.1.2 $PM_{2.5}$

$PM_{2.5}$ impacts will be modeled in accordance with USEPA guidance (USEPA, 2010a). A detailed discussion of how modeled $PM_{2.5}$ impacts will be evaluated is provided in Section 3.6.

3.2 Fumigation Modeling

The SCREEN3 model will be used to evaluate inversion breakup fumigation impacts for short-term averaging periods (24 hours or less), as appropriate. The methodology in "Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised" (USEPA, 1992b) will be followed for these analyses. Combined impacts for all sources under fumigation conditions will be evaluated, based on USEPA modeling guidelines.

3.3 Health Risk Assessment Modeling

A health risk assessment (HRA) will be performed according to California Air Resources Board (CARB) guidance. The HRA modeling will be prepared using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.4f, May 2012 using the latest HARP Health Database table updated in November 2013) and AERMOD with the CARB "on-ramp."[7] HARP will be used to assess cancer risk as well as non-cancer chronic and acute health hazards.

3.4 Meteorological Data

Meteorological data are required from two different types of monitoring locations: surface data that are representative of meteorological conditions near the earth, and upper air data that are representative of meteorological conditions well above the earth's surface.

There are many factors that go into a determination that meteorological data is "representative" of conditions in an area. Determinations are made on a case-by-case

[7] HARP has not yet been revised to utilize AERMOD, but CARB has developed "on-ramp" software that allows HARP to incorporate AERMOD output files. Therefore, HARP is now compatible with AERMOD.

basis, following EPA guidance. EPA's meteorological monitoring guidance for permit modeling[8] states:

> "Issues of representativeness will always involve case-by-case subjective judgments; consequently, experts knowledgeable in meteorological monitoring and air quality modeling should be included in the site selection process. The following information is provided for consideration in such decisions…
>
> - Although proximity of the meteorological monitoring site is an important factor, representativeness is not simply a function of distance. In some instances, even though meteorological data are acquired at the location of the pollutant source, they may not correctly characterize the important atmospheric dispersion conditions; e.g., dispersion conditions affecting sources located on the coast are strongly affected by off-shore air/sea boundary conditions - data collected at the source would not always reflect these conditions.
>
> - Representativeness is a function of the height of the measurement. For example, one can expect more site-to-site variability in measurements taken close to the surface compared to measurements taken aloft. As a consequence, upper-air measurements are generally representative of much larger spatial domains then are surface measurements…"

A five-year meteorological dataset (2009–2013) will be processed in AERMET (Version 14134) to generate AERMOD-compatible meteorological data for air dispersion modeling. The surface meteorological data were recorded at the nearby Blythe Airport monitoring station, and the upper air data were recorded at Elko, NV (WBAN No. 04105). Figure 1 above shows the relative locations of the project site and the meteorological monitoring station at the Blythe Airport. The Blythe Airport monitoring station is less than 3 km (less than 2 miles) from the project site with no intervening terrain, so surface meteorological data collected there are clearly representative of meteorological conditions at the site.

EPA defines the term "on-site data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and EPA's guidance on the use of on-site monitoring data are also outlined in the "On-Site Meteorological Program Guidance for Regulatory Modeling

[8] U.S. EPA, "Meteorological Monitoring Guidance for Regulatory Modeling Applications," EPA-454/R-99-005, February 2000; available at *http://www.epa.gov/ttn/scram/guidance/met/mmgrma.pdf.*

Applications" (USEPA, 1987a). The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected.

Representativeness has also been defined in "The Workshop on the Representativeness of Meteorological Observations" (Nappo et. al., 1982) as "the extent to which a set of measurements taken in a space-time domain reflects the actual conditions in the same or different space-time domain taken on a scale appropriate for a specific application." Representativeness is best evaluated when sites are climatologically similar, as are the project site and the Blythe Airport meteorological monitoring station.

Representativeness has additionally been defined in the PSD Monitoring Guideline (USEPA, 1987b) as data that characterize the air quality for the general area in which the Proposed Project would be constructed and operated. Because of the close proximity of the Blythe meteorological data site to the project site (distance between the two locations is approximately 2.8 km, or 1.74 miles), the same large-scale topographic features that influence the meteorological data monitoring station also influence the project site in the same manner.

There are few locations where upper air data are available; when looking at the representativeness of upper air data, the most important factors are distances relative to large urbanized areas and coastal zones. The Elko upper air monitoring station was selected because it is the nearest station with complete and representative upper air data for the five-year period. The Elko monitoring station is located in the Nevada desert, 810 km (500 miles) from the project site. The San Diego upper air station (located at Miramar Naval Air Station) is closer to the project site (246 km, or 153 miles), but because of the coastal location of the Miramar monitoring station, we do not believe that upper air data collected there would be representative of atmospheric conditions at the project site. Upper air data is also available from Tucson, AZ, 388 km (241 miles) from the project site. However, an assessment of the upper air data from Tucson reveals that missing surface data in the soundings in the period 2009-2011 to make it impossible for the full five-year dataset to meet EPA completeness criteria (that is, less than 10% of missing readings on a quarterly basis). In addition, the Tucson location is significantly more urbanized than the project area.

Thus, we determine that the meteorological data from these monitoring stations are representative of conditions at the Project site.

3.5 Receptor Grids

Receptor and source base elevations will be determined from USGS National Elevation Dataset (NED) data in the GeoTIFF format at a horizontal resolution of 1 arc-second (approximately 30 meters). All coordinates will be referenced to UTM North American Datum 1983 (NAD83), Zone 11. The AERMOD receptor elevations will be interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option will be chosen.

Cartesian coordinate receptor grids will be used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid will be developed and will extend outwards at least 10 km (or more if necessary to establish the significant impact area).

For the full impact analyses, a nested grid will be developed to fully represent the maximum impact area(s). The receptor grid will be constructed as follows:

1. One row of receptors spaced 25 meters apart along the facility's fence line;

2. Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line;

3. Additional tiers of receptors spaced 100 meters apart, extending from 100 meters to 1,000 meters from the fenceline; and

4. Additional tiers of receptors spaced 250 meters apart, out to at least 10 km from the most distant source modeled, not to exceed 50 km from the project site.

Additional refined receptor grids with 25-meter resolution will be placed around the maximum first-high or maximum second-high coarse grid impacts and extended out 1,000 meters in all directions. Concentrations within the facility fenceline will not be calculated.

3.6 Ambient Air Quality Impact Analyses (AQIA)

Emissions from the Proposed Project will result from combustion of fuel in the gas turbines and from the hybrid partial dry cooling systems. These emission sources will be modeled as point sources. The expected emission rates will be based on vendor data and additional conservative assumptions of equipment performance.

The purpose of the ambient air quality impact analysis is to demonstrate compliance with applicable ambient air quality standards. Both USEPA and the District have regulations that prohibit construction of a project that will cause or contribute to violations of applicable standards.

Based on EPA guidance, if, for a given pollutant and averaging time, the project's impact is below the Significant Impact Levels (SILs) shown in Table 1, the project's impact is deemed to be *de minimis,* and no further analysis is required. However, if the modeled impacts exceed any of the significance thresholds displayed in Table 1, the project has the

Table 1 Significant Impact Levels for Air Quality Impacts in Class II Areas ($\mu g/m^3$)					
	Averaging Period				
Pollutant	Annual	24-hour	8-hour	3-hour	1-hour
NO_2	1	--	--	--	7.5[9]
SO_2	1	5	--	25	7.8[10]
CO	--	--	500	--	2000
PM_{10}	1	5	--	--	--
$PM_{2.5}$[10]	0.3	1.2	--	--	--

potential to cause or contribute to a violation of the ambient air quality standard at the times and locations where the threshold is exceeded. In that case, the analysis must consider the contribution of other sources to the ambient concentration. If the analysis indicates that there will be a violation of an ambient air quality standard, and the project's impact at the time and place of the violation is significant, then the project may not be approved unless the project's impact is reduced.

An air quality impact analysis is required for certification by the CEC and to support the air quality impact analysis, PSD analysis, and screening health risk assessment that are required by the District. Each agency has its own criteria for preparation of the air quality impact analysis; however, the criteria used by the CEC and the District are similar enough that the same basic analysis, with some variations, will satisfy both agencies.

3.6.1 Step 1: Project Impact

The first step in the compliance demonstration is to determine, for each pollutant and averaging period, whether the proposed new equipment for the project has the potential to cause a significant ambient impact at any location, under any operating or meteorological conditions. As indicated in the NSR Workshop Manual,[11] "[i]f the significant net emissions increase from a proposed source would not result in a significant ambient impact anywhere, the application is usually not required to go beyond a preliminary analysis in order to make the necessary showing of compliance for a particular pollutant." The EPA significance levels for air quality impacts are shown in Table 1. If the

[9] EPA has not yet defined significance levels (SILs) for one-hour NO_2 and SO_2 impacts. However, EPA has suggested that, until SILs have been promulgated, interim values of 4 ppb (7.5 $\mu g/m^3$) for NO_2 and 3 ppb (7.8 $\mu g/m^3$) for SO_2 may be used (USEPA (2010c); USEPA (2010d)). These values will be used in this analysis as interim SILs.
[10] In January 2013, the D.C. Circuit Court of Appeals ruled that the $PM_{2.5}$ SIL could not be used as a definitive exemption from the requirements to perform $PM_{2.5}$ preconstruction monitoring or a $PM_{2.5}$ increments analysis or AQIA. However, EPA's March 2013 interpretation of the Court's decision indicated that the SIL can be used as guidance.
[11] USEPA (1990), p. C.51.

maximum modeled impact for any pollutant and averaging period is below the appropriate significance level in this table, no further analysis is necessary.[12]

Based on the following USEPA (2010e) guidance, no further analysis is necessary for any location where the modeled impacts from the project alone are below the significance thresholds.

> *The primary purpose of the SILs is to identify a level of ambient impact that is sufficiently low relative to the NAAQS or increments that such impact can be considered trivial or de minimis. Hence, the EPA considers a source whose individual impact falls below a SIL to have a de minimis impact on air quality concentrations that already exist. Accordingly, a source that demonstrates that the projected ambient impact of its proposed emissions increase does not exceed the SIL for that pollutant at a location where a NAAQS or increment violation occurs is not considered to cause or contribute to that violation. In the same way, a source with a proposed emissions increase of a particular pollutant that will have a significant impact at some locations is not required to model at distances beyond the point where the impact of its proposed emissions is below the SILs for that pollutant. When a proposed source's impact by itself is not considered to be "significant," EPA has long maintained that any further effort on the part of the applicant to complete a cumulative source impact analysis involving other source impacts would only yield information of trivial or no value with respect to the required evaluation of the proposed source or modification.*[13]

For $PM_{2.5}$, the highest average of the maximum annual averages and of the 24-hour averages modeled over the five years of meteorological data will be compared with the SILs in Table 1 to determine whether the modeled $PM_{2.5}$ project impacts are significant.[14] For other pollutants, the highest modeled concentrations will be compared with the SILs. For pollutants with modeled project impacts below the significance thresholds, a summary table will show the maximum modeled project impacts plus background concentrations. Although this information is not required by federal modeling guidance, it will be provided as part of the CEQA analysis.

3.6.2 Step 2: Project Plus Background

Pollutants/averaging periods that are not screened out in Step 1 are required to undergo a full air quality impact analysis. In Step 2, the ambient impacts of the project are modeled and added to background concentrations. The results are compared to the relevant state and federal ambient standards.

[12] With the potential exception of the $PM_{2.5}$ SILs. See footnote 10.
[13] USEPA (2010e), p. 64891.
[14] USEPA (2010a), p. 6.

The second step of the compliance demonstration is required to show that the proposed new project, in conjunction with existing sources, will not cause or contribute to a violation of any ambient air quality standard. As discussed in more detail below, the impacts of existing sources are represented by the existing ambient air quality data collected at the monitoring stations shown in Table 2. In accordance with Section 8.2.1 of Appendix W to 40 CFR Part 51:

> *Background concentrations are an essential part of the total air quality concentration to be considered in determining source impacts. Background air quality includes pollutant concentrations due to: (1) Natural sources; (2) nearby sources other than the one(s) currently under consideration; and (3) unidentified sources. Typically, air quality data should be used to establish background concentrations in the vicinity of the source(s) under consideration.*

If a Step 2 analysis is required, the modeled impacts from the Proposed Project will be added to the representative background concentration for comparison with the California and National Ambient Air Quality Standards (CAAQS and NAAQS). In accordance with USEPA guidelines,[15] the highest second-highest modeled concentrations will be used to demonstrate compliance with the short-term federal standards (except for the statistically based federal one-hour NO_2 and SO_2, and 24-hour $PM_{2.5}$, standards) and the highest modeled concentration will be used to demonstrate compliance with the federal annual standards and all state standards. If the predicted total ground-level concentration is below the state or federal ambient air quality standard for each pollutant and averaging period, no further analysis is required for that pollutant and averaging period.

<u>3.6.3 Compliance with Statistically Based Standards</u>

For the one-hour average federal NO_2 standard for the District and CEC analyses, the comparison of impacts with the new federal one-hour standard will be done in accordance with Appendix W of Part 51 of Title 40 of the CFR "Guideline on Air Quality Models" and the tiered process presented in "Modeling Compliance of the Federal 1-Hour NO_2 NAAQS" (CAPCOA guidance document, 2011)[16] together with clarification as provided by the 2011 Tyler Fox memorandum.[17] Appendix W of Part 51 of Title 40 of the CFR "Guideline on Air Quality Models" has codified three methods that can be used to estimate NO_2 concentration (Tier 1 - Total Conversion, Tier 2 - Ambient Ratio Method or ARM, Tier 3 - Ozone Limiting Method or OLM). According to USEPA guidance (USEPA, 2011a):

[15] USEPA (2005), 11.2.3.2 and 11.2.3.3

[16] California Air Pollution Control Officers Association, "Modeling Compliance of The Federal 1-Hour NO_2 NAAQS," October 27, 2011. Available at http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf.

[17] U.S. EPA. "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NOx National Ambient Air Quality Standard," Tyler Fox, March 1, 2011.

> *While the limited scope of the available field study data imposes limits on the ability to generalize conclusions regarding model performance, these preliminary results of hourly NO_2 predictions for Palau and New Mexico show generally good performance for the PVMRM and OLM/OLMGROUP ALL options in AERMOD. We believe that these additional model evaluation results lend further credence to the use of these Tier 3 options in AERMOD for estimating hourly NO_2 concentrations, and we recommend that their use should be generally accepted provided some reasonable demonstration can be made of the appropriateness of the key inputs for these options, the in-stack NO_2/NOx ratio and the background ozone concentrations.*[18]

As discussed above, for the new gas turbines the in-stack NO_2/NOx ratios will be consistent with the ratios used during the permitting of the NRG Carlsbad Energy Center and Apex Pio Pico Projects.[19] Background ozone concentrations in the project area will be represented by five years of ozone data (2009–2013) collected at Blythe concurrently with the meteorological data. Based on these factors, we propose to use the Tier 3, “OLMGROUP ALL,” option for modeling 1-hour NO_2 concentrations.

For demonstrating compliance with the statistically based federal one-hour NO_2 standard, CAPCOA’s 2011 guidance document (CAPCOA, 2011) provides 11 progressively more sophisticated methods for combining modeled NO_2 concentrations with background (or monitored) NO_2. These methods, outlined below, were developed to allow demonstration of compliance using the lowest amount of resources necessary. Each tier is a progressively more sophisticated and comprehensive analysis that reduces the level of conservatism without reducing the level of assurance of compliance.

1. Significant Impact Level (SIL) – no background required
2. Max modeled value + max monitored value
3. Max modeled value + 98th pctl monitored value
4. 8th highest modeled value + max monitored value
5. 8th highest modeled value + 98th pctl monitored value
6. (5 yr avg of 98th pctl modeled value) + max monitored value
7. (5 yr avg of 98th pctl of modeled value) + 98th pctl monitored value
8. 5 yr avg of 98th pctl of (modeled value + monthly hour-of-day – 1st high)
9. 5 yr avg of 98th pctl of (modeled value + seasonal hour-of-day – 3rd high)
10. 5 yr average of 98th pctl of (modeled value + annual hour-of-day - 8th high)
11. Paired-Sum: 5 yr avg of 98th pctl of (modeled value + background)

---

[18] The Plume Volume Molar Ratio Method (PVMRM) is considered by USEPA to be a Tier 3 screening method, similar to OLM. (USEPA, 2011a).

[19] If the project includes emergency engines, NO_2/NOx ratios of 18% and 14% will be used for the Diesel emergency firepump and black start engines, respectively. These ratios were provided by the San Diego APCD staff for the NRG Carlsbad Energy Center amendment application filed in May 2014.

Applicable definitions are provided below.

- *Significant Impact Level (SIL)* is defined as a de minimis impact level below which a source is presumed not to cause or contribute to an exceedance of a NAAQS (see Table 1 above).

- *Max modeled value* is defined as the maximum concentration predicted by the model at any given receptor in any given year modeled.

- *8^{th} highest modeled value* is defined as the highest 8^{th}-highest concentration derived by the model at any given receptor in any given year modeled.

- *5 yr avg of the 98^{th} pctl* is defined as the highest of the average 8^{th} highest (98th percentile) concentrations derived by the model across all receptors based on the length of the meteorological data period or the X years average of 98^{th} percentile of the annual distribution of daily maximum one-hour concentrations across all receptors, where X is the number of years modeled. (In Appendix W, EPA recommends using five years of meteorological data from a representative National Weather Service site or one year of on-site data.)

- *Monthly hour-of-day* is defined as the three-year average of the 1^{st} highest concentrations (Maximum Hourly) for each hour of the day.

- *Seasonal Hour-Of-Day* is defined as the three-year average of the 3^{rd} highest concentrations for each hour of the day and season.

- *Annual hour-of-day* is defined as the three-year average of the 8^{th} highest concentration for each hour of the day.

- *Paired-Sum* **(**5 yr avg of the 98^{th} pctl) is the merging of the modeled concentration with the monitored values paired together by month, day, and hour. The sum of the paired values is then processed to determine the X-year average of the 98^{th} percentile of the annual distribution of daily maximum one-hour concentrations across all receptors, where X is the number of years modeled.

For the demonstration of compliance with the federal one-hour NO_2 standard, we will perform analyses at as many of the following tiers as are needed to demonstrate compliance with the state and federal ambient air quality standards: Tier 1, Tier 2, Tier 7, Tier 8, Tier 9, Tier 10, and Tier 11. Hourly NO_2 background data (for the same five years of meteorological data used for the modeling—2009 to 2013) may also be used in order to refine the NAAQS analysis both spatially and temporally. In the event of missing hourly NO_2 data, the missing data procedures described in Section 3.7.1 will be followed to fill in gaps in the hourly NO_2 data. To account for recently permitted nearby stationary sources that are not reflected in the background NO_2 data, we will review the list of projects provided by the MDAQMD (the request for these projects is discussed in Section 3.10) and model the impacts from projects with a NOx net emission increase greater than 5 tons/year (excluding intermittently operated equipment per EPA guidance).[20] The nearby BEP project will be included in the modeled background as its emissions would not be monitored at the NO_2 background station.

The demonstration of compliance with the federal one-hour SO_2 standard will follow the same steps, except that it will utilize the 99th percentile predicted one-hour average SO_2 concentrations instead of the 98th percentile.

For the 24-hour average federal $PM_{2.5}$ standard for the District and CEC analyses, the comparison of impacts with the federal 24-hour average standard will be done in accordance with USEPA March 23, 2010 guidance (USEPA, 2010a). This guidance calls for basing the initial determination of compliance with the standard on the five-year average of the highest modeled annual and 24-hour averages, combined with background concentrations based on the form of the standards (the three-year average of the annual $PM_{2.5}$ concentrations and the three-year average of the 98th percentile 24-hour averages).[21] If a more detailed assessment of $PM_{2.5}$ impacts is required, a Tier 2 analysis will be performed. USEPA's March 23, 2010 memo provides minimal guidance regarding this type of more detailed analysis, saying only "a Second Tier modeling analysis may be considered that would involve combining the monitored and modeled $PM_{2.5}$ concentrations on a seasonal or quarterly basis, and re-sorting the total impacts across the year to determine the cumulative design value."[22] As no additional guidance has been provided, such an analysis would be discussed with the District and CEC staff prior to implementation.

3.6.4 State One-Hour NO_2 Standard

Compliance with the state one-hour NO_2 standard will be demonstrated using OLM and the paired-sum approach described above, except that the analysis will use highest, rather than 98th percentile concentrations, consistent with the form of the state standard.

3.7 Background Ambient Air Quality Data

Background ambient air quality data for the project area will be obtained from the monitoring sites most representative of the conditions that exist at the proposed project site. Modeled concentrations will be added to these representative background concentrations to demonstrate compliance with the CAAQS and NAAQS.

Table 2 shows the monitoring stations we propose to use as they provide the most representative ambient air quality background data. Where possible, recommended background concentration measurements should come from nearby monitoring stations with similar site characteristics. For this proposed project, the Blythe monitoring station

[20] USEPA (2011a), page 10.
[21] USEPA (2010a), p. 9.
[22] USEPA (2010a), p. 8.

Table 2 **Representative Background Ambient Air Quality Monitoring Stations**		
Pollutant(s)	Monitoring Station	Distance to Project Site
$PM_{2.5}$, CO, PM_{10}, and NO_2	Palm Springs	181 km
SO_2	Victorville	263 km
O_3	Blythe	7.8 km

(ozone) is the closest monitoring station. The Palm Springs monitoring station (PM_{10}, $PM_{2.5}$, NO_2, and CO) is located 181 km west of the project site. The Victorville monitoring station (SO_2) is located 263 km west northwest of the project site. In general, the Palm Springs and Victorville monitoring stations are considered to provide conservative estimates of the worst case background concentrations due to their proximity to the South Coast Air Basin (Metropolitan Los Angeles). Monitoring stations located in Imperial County were not considered to be representative of conditions at the project site due to the predominant air flow patterns and due to air pollution from Mexico that creates a significant local influence for the worst-case pollutant concentration readings at some locations in Imperial County.

For annual NO_2, 24-hour and annual SO_2, and all PM_{10} and CO averaging periods, the highest values monitored during the 2009–2013 period will be used to represent ambient background concentrations in the project area. The one-hour average NO_2 analyses will be performed as described above. For analyses of federal 24-hour and annual $PM_{2.5}$ impacts, the three-year average of the 98th percentile 24-hour monitored levels for the period between 2009 and 2013 will be used to represent project area background because these values correspond to the method used for determining compliance with the federal $PM_{2.5}$ standards and are consistent with the guidance cited above.

3.7.1 Missing Data Protocol

Using the OLM method to model project-generated one-hour NO_2 concentrations requires the use of ambient monitored O_3 concentrations. Because the OLM method uses the ambient ozone concentration for a particular hour to limit the conversion of NO to NO_2, it is important to have ozone concentrations for every hour. It is also important that any missing hourly ozone concentrations be filled in with a value that does not underestimate the ozone concentration for that hour, to avoid underestimating the resulting NO_2 concentration. In addition, computation of total hourly NO_2 concentrations requires use of the ambient monitored hourly NO_2 concentrations from the nearest monitoring station. As is the case for the hourly ozone data, it is important to have a background NO_2 value for every hour that does not underestimate actual background.

As discussed above, background ambient hourly O_3 and NO_2 data were collected at the monitoring stations at Blythe and Palm Springs, respectively. While these datasets are expected to exceed USEPA's 90% completeness criterion (that is, more than 90% of the data values are present for each month), there are still occasional missing values that must be filled in. Missing NO_2 and O_3 data will be filled in following guidance developed by the San Joaquin Air Pollution Control District (SJVAPCD) in collaboration with CAPCOA (CAPCOA, 2011).[23] The option in AERMOD for a default background ozone value to be used in lieu of missing values (e.g., 40 ppb) will not be used.

a. Fill any *single missing hour* with the maximum of the:
   i. Preceding hour;
   ii. Succeeding hour;
   iii. Same hour of day on previous day; or
   iv. Same hour of day on succeeding day

If there are missing data for either iii and/or iv, use only the maximum of the available data to fill the missing hour (both a and b are guaranteed to be present since only single missing hours are filled in this step). Note that the most likely scenario for both c and d to be missing is for years when the monitor is calibrated at the same hour each day. In this case, the 30-day rolling average (see step b) for that hour will also not be available.

b. For hours that are not filled by step a (all periods with *more than one hour missing*), fill the missing hour with the maximum for that hour of day for a 30-day rolling period centered on the hour (i.e., for the 15 preceding days and the 15 succeeding days). Note that 30-day rolling period will extend into the preceding and succeeding year at the start or end, respectively, of the modeling period.

c. For hours not filled by step b, fill the missing data with the maximum of the 30-day rolling period for the preceding or succeeding hour.

d. Any hours not filled by steps a–c are likely periods with more than a month of missing data for all hours. These will be filled on a case-by-case basis, following the CAPCOA guidance cited above, and gap filling will be documented in the modeling section of the applications.

3.8 Health Risk Assessment

A health risk assessment will be performed according to the most current Office of Environmental Health Hazard Analysis (OEHHA) risk assessment guidance and software adopted and available at the time the risk assessment is prepared. OEHHA is currently in

[23] EPA's March 2011 guidance document on 1-hour NO_2 modeling does not address missing hourly NO_2 data. However, the CAPCOA guidance document indicates that the recommended technique for filling single missing hours of NO_2 is consistent with the gap filling technique established by EPA for filling a single hour of missing met data. All missing data procedures are subject to approval by the reviewing agencies.

the process of revising its “Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments,” and CARB is in the process of updating the Hotspots Analysis and Reporting Program (HARP) software to implement the updated OEHHA guidance; however, it is not clear when either revision will be released publicly. The HRA modeling will be executed using CARB’s HARP computer program with the latest available health database (most recent version is dated July 3, 2014). The HARP model will be used to assess cancer risk as well as non-cancer chronic and acute health hazards.

The HARP model incorporates the ISCST3 model previously approved by USEPA. CARB offers a software program that allows AERMOD data to be imported into the HARP model, called HARP On-Ramp. The on-ramp will be used with the most recent versions of AERMOD and HARP for the screening risk assessment. The following HARP default options will be used for the health risk assessment:

- Home grown produce selected (0.15 for the fraction for leafy, exposed, protected, and root vegetables);
- Dermal absorption selected (0.02 m/s deposition rate);
- Soil ingestion selected (0.02 m/s deposition rate); and
- Mother’s milk selected (0.02 m/s deposition rate).

3.9 Construction Air Quality Impact Assessment for the CEQA Analysis

The potential ambient impacts from air pollutant emissions during the construction activities associated with the proposed project will be evaluated by air quality modeling that will account for the construction site location and the surrounding topography; the sources of emissions during construction, including vehicle and equipment exhaust emissions; and fugitive dust.

Types of Emission Sources − Construction of the proposed project can be viewed as three main sequential phases: site preparation; construction of foundations; and installation of the gas turbines and associated equipment. The construction impacts analysis will include a schedule for construction operation activities. Site preparation includes site excavation, excavation of footings and foundations, and backfilling operations.

Fugitive dust emissions from the construction of the Proposed Project result from the following activities:

- Excavation and grading at the construction site;
- Onsite travel on paved and unpaved roads and across the unpaved construction site;
- Aggregate and soil loading and unloading operations;
- Raw material transfer to and from material stockpiles; and
- Wind erosion of areas disturbed during construction activities.

Engine exhaust will be emitted from the following sources:

- Heavy equipment used for excavation, grading, and construction of onsite structures;
- Water trucks used to control construction dust emissions;
- Diesel- and gasoline-fueled welding machines, generators, air compressors, and water pumps;
- Gasoline-fueled pickup trucks and Diesel-fueled flatbed trucks used onsite to transport workers and materials around the construction site;
- Transport of mechanical and electrical equipment to the project site;
- Transport of rubble and debris from the site to an appropriate landfill; and
- Transport of raw materials to and from stockpiles.

Emissions from a peak activity day will be modeled. Annual average emissions over the construction period will also be calculated and modeled for comparison with annual standards.

Existing Ambient Levels – The background data discussed earlier will be used to represent existing ambient levels for the construction analysis as well as the analysis of the impacts of project operations.

Model Options – The AERMOD "OLMGROUP ALL" option will be used to estimate ambient impacts from construction emissions. The modeling options and meteorological data described above will be used for the modeling analysis. A 10% NO_2/NOx fraction for Diesel demolition/construction equipment will be assumed (see Appendix B).

The construction sites will be represented as both a set of volume sources and a separate set of area sources in the modeling analysis. Emissions will be divided into three categories: exhaust emissions, mechanically generated fugitive dust emissions, and wind-blown fugitive dust emissions. Exhaust emissions and mechanically generated fugitive dust emissions (e.g., dust from wheels of a scraper) will be modeled as volume sources with a height of 6 meters. Wind-blown fugitive dust emissions and sources at or near the ground that are at ambient temperature and have negligible vertical velocity will be modeled as area sources with a release height of 0.5 meters.

Combustion Diesel PM_{10} emission impacts from construction equipment will be evaluated to demonstrate that the cancer risk from construction activities will be below ten in one million at all receptors.

For the construction modeling analysis, the receptor grid will begin at the property boundary and will extend approximately one kilometer in all directions. The receptor grid will be laid out as follows:

1. One row of receptors spaced 25 meters apart along the facility's fence line;

2. Four tiers of receptors spaced 25 meters apart, extending 100 meters from the fence line; and

3. Additional tiers of receptors spaced 60 meters apart, extending from 100 meters to 1,000 meters from the fenceline.

3.10 Cumulative Air Quality Impact Analysis

To address CEC requirements, a cumulative air quality modeling impacts analysis of the project's typical operating mode will be performed in combination with other stationary source emissions sources within a six-mile radius that have received Authorities to Construct and/or modified permits to operate since August 2012, or are in the permitting process. For each criteria pollutant, facilities having an emission increase of less than five tons per year are generally considered to be *de minimis*, and these facilities may be excluded from the cumulative impacts analysis. Information on any recently constructed/permitted sources that might be appropriate for a cumulative air quality impact analysis (as defined above) will be requested from the MDAQMD. The analysis will include the operational Blythe Energy Project and the licensed, but not constructed, Blythe II Power Plant] in combination with the proposed project.

Upon receipt of sufficient information from the local air agencies to allow air dispersion modeling of the recently constructed/permitted non-project sources to be included in the cumulative air quality impact analysis, AERMOD will be used in a procedure similar to that described earlier in this protocol.

3.11 Nitrogen Deposition Analysis

As part of the Application for Certification filed with the CEC, it will be necessary to include a nitrogen deposition analysis. Nitrogen deposition is the input of NOx and ammonia (NH_3) derived pollutants, primarily nitric acid (HNO_3), from the atmosphere to the biosphere. Nitrogen deposition can lead to adverse impacts on sensitive species including direct toxicity, changes in species composition among native plants, and enhancement of invasive species.

We will perform a nitrogen deposition modeling analysis examining the impacts on nearby areas classified as critical habitat and/or areas containing sensitive biological resources. The analysis will compare the nitrogen deposition associated with the nitrogen emissions from the project with established nitrogen disposition significance thresholds. The AERMOD model will be used for this analysis. However, as discussed in the CEC staff's assessment of nitrogen deposition impacts for the Huntington Beach Energy Project, AERMOD tends to produce conservatively high predictions of nitrogen deposition rates.[24] The assessment of significance for nitrogen deposition impacts will consider appropriate adjustments to background nitrate concentrations as well as emissions offsets provided for the project. If the maximum modeled nitrogen deposition impacts are determined to be significant, the Applicant will work with Staff to evaluate whether additional mitigation measures are needed.

[24] CEC, Final Staff Assessment for the Huntington Beach Energy Project, May 2014; Appendix BIO-1.

4. REPORTING

The results of the criteria pollutant and TAC modeling will be integrated into the application documents, and will include the information listed below.

- Project Description – Site map and site plan along with descriptions of the emitting equipment and air pollution control systems.

- Model Options and Input – Model options, screening and refined source parameters, criteria pollutant and TAC emission rates, meteorological data, and receptor grids used for the modeling analyses.

- Air Dispersion Modeling – Dispersion modeling results will include the following:

  – Plot plan showing emission points, nearby buildings (including dimensions), cross-section lines, property lines, fence lines, roads, and UTM coordinates;

  – A table showing building heights used in the modeling analysis;

  – Summaries of maximum modeled impacts; and

  – Model input and output files, including BPIP-PRIME and meteorological files as well as hourly ozone and NO_2 files used in demonstrating compliance with the 1-hour NO_2 standard, in electronic format on a compact disc, together with a description (README file) of all filenames.

- HRA – The HRA will include the following:

  – Descriptions of the methodology and inputs to the demolition/construction and operation AERMOD runs;

  – Tables of TAC emission rates and health impacts;

  – Figures showing sensitive receptor locations; and

  – Model input and output files in electronic format on a compact disc, together with a description (README file) of all filenames.

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Appendix A

Information on CTSCREEN Model

The CTDMPLUS and CTSCREEN Models

Complex terrain impacts may need to be modeled with more accuracy than that provided by AERMOD. The use of more refined modeling techniques is specifically addressed in USEPA's Appendix W[1] modeling guidance, as follows:

> *Since AERMOD treats dispersion in complex terrain, we have merged sections 4 and 5 of appendix W, as proposed in the April 2000 NPR [Notice of Proposed Rulemaking]. And while AERMOD produces acceptable regulatory design concentrations in complex terrain, it does not replace CTDMPLUS for detailed or receptor-oriented complex terrain analysis, as we have made clear in Guideline section 4.2.2. CTDMPLUS remains available for use in complex terrain. [p. 68225]*
>
> *4.2.2 Refined Analytical Techniques*
> *d. If the modeling application involves a well defined hill or ridge and a detailed dispersion analysis of the spatial pattern of plume impacts is of interest, CTDMPLUS, listed in Appendix A, is available. CTDMPLUS provides greater resolution of concentrations about the contour of the hill feature than does AERMOD through a different plume-terrain interaction algorithm. [p. 68233]*

CTSCREEN is the same basic model as CTDMPLUS, except that meteorological data are handled internally in a simplified manner. As discussed in the CTSCREEN users guide:[2]

> *Since [CTDMPLUS] accounts for the three-dimensional nature of plume and terrain interaction, it requires detailed terrain and meteorological data that are representative of the modeling domain. Although the terrain data may be readily obtained from topographic maps and digitized for use in the CTDMPLUS, the required meteorological data may not be as readily available.*
>
> *Since the meteorological input requirements of the CTDMPLUS can limit its application, the EPA's Complex-Terrain-Modeling, Technology-Transfer Workgroup developed a methodology to use the advanced techniques of CTDMPLUS in situations where on-site meteorological measurements are limited or unavailable. This approach uses CTDMPLUS in a "screening" mode--actual source and terrain*

[1] 40 CFR 51 Subpart W, as amended November 9, 2005 at 70 FR 68218, "Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions."
[2] USEPA, EPA-600/8-90-087, "User's Guide to CTDMPLUS: Volume 2. The Screening Mode (CTSCREEN)," October 1990.

characteristics are modeled with an extensive array of predetermined meteorological conditions.

This CTDMPLUS screening mode (CTSCREEN) serves several purposes in regulatory applications. When meteorological data are unavailable, CTSCREEN can be used to obtain conservative (safely above those of refined models), yet realistic, impact estimates for particular sources.

Therefore, the use of the CTSCREEN version of CTDMPLUS is consistent with USEPA guidance.

Appendix B

Proposed NO_2/NOx Ratios for Modeling Compliance with One-Hour NO_2 Standards for Diesel Engines Used in Construction Activities

Proposed NO_2/NOx Ratios for Modeling Compliance with One-Hour NO_2 Standards for Emergency Engines and for Construction Activities

The use of the Tier 3 Plume Volume Molar Ratio Method (PVMRM) and Ozone Limiting Method (OLM) options in AERMOD requires the specification of an in-stack ratio (ISR) of NO_2/NOx for each NOx emissions source. The October 27, 2011, California Air Pollution Control Officers Association (CAPCOA) Guidance Document, titled "Modeling Compliance of The Federal 1-Hour NO_2 NAAQS,"[27] emphasized the importance of these in-stack ratios for the 1-hour NO_2 NAAQS, recommending that in-stack ratios used with either the OLM or PVMRM options be justified based on the specific application.

USEPA's Office of Air Quality Planning and Standards (OAQPS) is in the process of creating a database of test results that support in-stack NO_2/NOx ratios for specific source types. We are proposing to use USEPA's ISR database for the Project.

USEPA's ISR database is at *http://www.epa.gov/ttn/scram/no2_isr_database.htm*. As of August 2014, the file NO2_ISR_database.xlsx, which is to provide the NO_2 ISR data that have been submitted via the formal collection initiated by OAQPS, contained listings for several Diesel engines.

Following is a description of the procedures followed to obtain proposed NO_2/NOx ratios from the ISR database for the equipment associated with the Proposed Project.

Diesel Emergency Engines and Construction Equipment

1. Sort by fuel to select all Diesel, #2 Diesel, and blank fuel fields to eliminate natural gas, biogas, and waste gas-fueled engines, leaving 40 records.

2. Eliminate any engines equipped with SCR (including the GE LeanNOx System)—the construction equipment Diesel engines will not have SCR, leaving 39 records.

The remaining engines range in size from 440 kW to 4,400 kW (590 to 5,900 hp). The NO_2/NOx ratios range from 2.2% to 9.9%, with an average of 6.2%. We propose to use a ratio of 10% as reasonable and conservative for the construction equipment.

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[27] California Air Pollution Control Officers Association (2011). "Modeling Compliance of The Federal 1-Hour NO2 NAAQS." Available at *http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf*.

Mojave Desert Air Quality Management District
14306 Park Avenue, Victorville, CA 92392-2310
760.245.1661 • fax 760.245.2699
Visit our web site: http://www.mdaqmd.ca.gov
Eldon Heaston, Executive Director

September 18, 2014

Ms. Nancy Mathews
Sierra Research
1801 "J" Street
Sacramento, CA 95811

Subject: AltaGas Kananaskis Energy Project Modeling Protocol

Dear Ms. Mathews:

The Mojave Desert Air Quality Management (District) received the air quality modeling protocol for the proposed AltaGas Kananaskis Energy Project (KEP) simple-cycle power plant to be located near Blythe in Riverside County. The District approves of the submitted KEP modeling protocol with exception that KEP include all proposed equipment (equipment not exempt per District Rule 219) and add to the background ambient air quality data significant nearby sources within a 6 mile radius of the proposed site. Below is a list of significant projects for which the District has issued permits (or in the process of issuing permits) and are located within 6 miles of the proposed KEP project site. All significant projects located within the 6 mile radius are approved California Energy Commission (CEC) Projects. The list below provides for each project- name, address, and CEC docket number.

<u>Blythe Energy Project</u>; Hobsonway & Buck Boulevard, Blythe, California. CEC Docket number 99-AFC-8.

<u>Blythe Energy Project, Phase II</u>; BEPII site boundary is located on approximately a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEPI). CEC Docket number 02-AFC-1.

Should you have any questions please contact Mr. Christian Anderson, (760) 245-1661 extension 1846.

Sincerely,

Christopher A. Collins

Supervising Air Quality Engineer

cja

October 2, 2014

sierra research
1801 J Street
Sacramento CA 95811
Tel: (916) 444-6666
Fax: (916) 444-8373

Ann Arbor MI
Tel: (734) 761-6666
Fax: (734) 761-6755

Memo to: Gerry Bemis, California Energy Commission

From: Nancy Matthews Nancy Matthews

Subject: Responses to CEC Staff Comments on Modeling Protocol
Kananaskis Energy Project

Attached please find responses to the comments provided by your staff on the modeling protocol for the Kananaskis Energy Project to be located in Blythe. The proposed NO_2/NOx ratio is discussed in the attached responses. As requested, we will provide additional justification for ratios used in the event the project includes stationary emergency diesel engines.

We appreciate your prompt review of the protocol. We will keep you apprised of any additional modeling issues that arise during our preparation of the Application for Certification.

Attachment

Cc: Christopher Doyle, AltaGas Power Holdings (U.S.) Inc.
Melissa Foster, Stoel Rives LLP
Jerry Salamy, CH2M Hill
Christopher A. Collins, MDAQMD

Responses to Comments from CEC Staff Regarding the Air Dispersion Modeling and Screening Health Risk Assessment Protocol for the Kananaskis Energy Project

Air Quality (CEC Staff comments dated September 18, 2014)

1. Page 4: the protocol shows that the applicant is going to use SCREEN3 version 96043. Staff checked EPA website and noticed the latest version of SCREEN3 is 13043. Please use most recent versions of the EPA approved models to evaluate the project impacts.

   The citation of SCREEN3 version 96043 in the protocol was a typographical error. The latest version of SCREEN3 and all other EPA guideline models will be used for the KEP ambient air quality modeling analyses.

2. Page 14: the applicant is planning to perform analyses at as many of the following tiers as are needed to demonstrate compliance with the state and federal ambient air quality standards (for NO_2): Tier 1, 2, 7, 8, 9, 10, and 11. Tier 11 corresponds to the paired-sum approach, which combines concurrent background and modeling concentrations on an hour-by-hour basis. In the March 1, 2011 memorandum ("Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard"), EPA states that it does not recommend the paired-sum approach except in rare cases when such an approach can be justified. Please refer to the EPA memorandum for more detailed discussions. Please provide justifications for the paired-sum approach if it will be used for the project.

   We do not expect to require the Tier 11 paired sum approach; however, if the paired-sum approach is used, we will provide additional justification as requested.

3. Page 16: the protocol states that for analyses of federal 24-hour and annual PM2.5 impacts, the three-year average of the 98^{th} percentile 24-hour monitored levels for the period between 2009 and 2013 will be used to represent project area background. While the federal 24-hour PM2.5 standard is based on the 98^{th} percentile values, the annual PM2.5 standard isn't. Please provide appropriate values according to the correct forms of the standards.

   The comment is correct. The maximum modeled annual average PM2.5 concentrations will be used to demonstrate compliance with the annual standard, consistent with the form of the standard.[1]

4. Footnote 6 of Page 5, Page 19, and Appendix B: page 5 of the protocol states that if the final project includes a diesel emergency firepump engine and/or a diesel emergency generator, the applicant will use a NO2/NOx ratio discussed in Appendix B. Page 19 of the protocol states that a 10% NO_2/NOx fraction for diesel demolition/construction equipment will be assumed based on Appendix B. Appendix B of the protocol states that the applicant obtained and filtered the NO_2/NOx in-stack ratio database from EPA website to come up with the 10% ratio. Staff checked the NO_2/NOx in-stack ratio table from the 2011 CAPCOA guidance document ("Modeling Compliance of the Federal 1-Hour NO2 NAAQS") and found: a) the default NO_2/NOx ratio recommended for diesel IC engines is 20%; b) the default NO_2/NOx ratios recommended for gas/diesel

[1] The federal annual standard is based on a 3-year average, while the state standard applies on an annual average basis.

light/medium duty truck/cars and diesel heavy duty truck/cars are 25% and 11% respectively. The protocol doesn't include information about the proposed diesel emergency engines or construction equipment. Staff can't determine if the 10% ratio filtered from EPA's database is applicable to this project. Staff recommend using more conservative ratios suggested by CAPCOA.

Consistent with the recommendations from CAPCOA and CEC staff, we will use the 11% NO_2/NOx ratio recommended by CAPCOA for diesel heavy duty trucks in our modeling analysis of diesel powered construction equipment, as the construction equipment is more similar to diesel heavy duty trucks than it is to light/medium duty trucks/cars. If the project includes stationary diesel emergency equipment (generator or fire pump engine), we will review the 10% ratio derived from the EPA ISR database to determine whether data for the specific engine models is available and will provide additional justification for the selected ratio(s).

5. Page 19: the protocol shows that the wind-blown fugitive dust emissions and sources will be modeled as area sources with a release height of 0.5 meters. Per South Coast Air Quality Management District's request for Redondo Beach and Huntington Beach projects, fugitive dust emissions should be modeled as a ground-level area source with an initial vertical dimension of 1 meter. Please use assumptions consistent with those used for the recent siting cases.

   We will follow CEC staff's recommendation for modeling wind-blown fugitive dust emission sources as ground-level area sources with an initial vertical dimension of 1 meter.

6. Page 19: the protocol states that for the construction modeling analysis, the receptor grid will begin at the property boundary and will extend approximately one kilometer in all directions. Although staff does not expect maximum construction impacts to occur far away from the project, staff has been using receptor grids extending 6 miles (10 kilometers). If one kilometer radius is used, please demonstrate maximum construction impacts do not occur beyond one kilometer radius.

   We agree with CEC staff that it is unlikely that maximum construction impacts will occur more than one kilometer away from the project boundary. However, we will make the requested demonstration to ensure that the maximum impacts are captured in our modeling analysis.

<u>Public Health (CEC staff comments dated September 23, 2014)</u>

1. P. 9 Receptor Grids

   Other than grid receptors, please also place receptors at:

   a. All sensitive locations (e.g., child care facilities, schools, hospitals, prisons, libraries, etc.) out to 1-mile, if any are identified.

   b. The nearest residences and off-site workers.

   Please also provide the excel file containing the information (i.e. HARP Receptor #, UTM Meters, Description,...) of these sensitive receptors.

   We will place additional receptors at the locations of any identified sensitive receptors, as well as at the locations of the nearest residences and off-site workers.

The requested Excel file summary of sensitive receptor numbers, locations and descriptions will also be provided as requested.

2. P.18 Health Risk Assessment

   If OEHHA/CARB updates the guidance and HARP before the file of AFC, please conduct the HRA according to the new guidance and by using software. The updated OEHHA guidance regarding **inhalation rate** and **age sensitivity factors** would increase the estimated risk at least 3 times more than the old method.

   As indicated in the protocol, OEHHA is currently in the process of revising its "Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments," and CARB is in the process of updating the Hotspots Analysis and Reporting Program (HARP) software to implement the updated OEHHA guidance; however, it is not clear when either revision will be released publicly. If an updated version of HARP is made available on ARB's website before the AFC is filed, we will use that updated version of HARP for preparing the screening health risk assessment.

Responses to Comments from CEC Staff Regarding the Air Dispersion Modeling and Screening Health Risk Assessment Protocol for the Kananaskis Energy Project

Air Quality (CEC Staff comments dated September 18, 2014)

1. Page 4: the protocol shows that the applicant is going to use SCREEN3 version 96043. Staff checked EPA website and noticed the latest version of SCREEN3 is 13043. Please use most recent versions of the EPA approved models to evaluate the project impacts.

   The citation of SCREEN3 version 96043 in the protocol was a typographical error. The latest version of SCREEN3 and all other EPA guideline models will be used for the KEP ambient air quality modeling analyses.

2. Page 14: the applicant is planning to perform analyses at as many of the following tiers as are needed to demonstrate compliance with the state and federal ambient air quality standards (for NO_2): Tier 1, 2, 7, 8, 9, 10, and 11. Tier 11 corresponds to the paired-sum approach, which combines concurrent background and modeling concentrations on an hour-by-hour basis. In the March 1, 2011 memorandum ("Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard"), EPA states that it does not recommend the paired-sum approach except in rare cases when such an approach can be justified. Please refer to the EPA memorandum for more detailed discussions. Please provide justifications for the paired-sum approach if it will be used for the project.

   We do not expect to require the Tier 11 paired sum approach; however, if the paired-sum approach is used, we will provide additional justification as requested.

3. Page 16: the protocol states that for analyses of federal 24-hour and annual PM2.5 impacts, the three-year average of the 98^{th} percentile 24-hour monitored levels for the period between 2009 and 2013 will be used to represent project area background. While the federal 24-hour PM2.5 standard is based on the 98^{th} percentile values, the annual PM2.5 standard isn't. Please provide appropriate values according to the correct forms of the standards.

   The comment is correct. The maximum modeled annual average PM2.5 concentrations will be used to demonstrate compliance with the annual standard, consistent with the form of the standard.[1]

4. Footnote 6 of Page 5, Page 19, and Appendix B: page 5 of the protocol states that if the final project includes a diesel emergency firepump engine and/or a diesel emergency generator, the applicant will use a NO2/NOx ratio discussed in Appendix B. Page 19 of the protocol states that a 10% NO_2/NOx fraction for diesel demolition/construction equipment will be assumed based on Appendix B. Appendix B of the protocol states that the applicant obtained and filtered the NO_2/NOx in-stack ratio database from EPA website to come up with the 10% ratio. Staff checked the NO_2/NOx in-stack ratio table from the 2011 CAPCOA guidance document ("Modeling Compliance of the Federal 1-Hour NO2 NAAQS") and found: a) the default NO_2/NOx ratio recommended for diesel IC engines is 20%; b) the default NO_2/NOx ratios recommended for gas/diesel

[1] The federal annual standard is based on a 3-year average, while the state standard applies on an annual average basis.

light/medium duty truck/cars and diesel heavy duty truck/cars are 25% and 11% respectively. The protocol doesn't include information about the proposed diesel emergency engines or construction equipment. Staff can't determine if the 10% ratio filtered from EPA's database is applicable to this project. Staff recommend using more conservative ratios suggested by CAPCOA.

Consistent with the recommendations from CAPCOA and CEC staff, we will use the 11% NO_2*/NOx ratio recommended by CAPCOA for diesel heavy duty trucks in our modeling analysis of diesel powered construction equipment, as the construction equipment is more similar to diesel heavy duty trucks than it is to light/medium duty trucks/cars. If the project includes stationary diesel emergency equipment (generator or fire pump engine), we will review the 10% ratio derived from the EPA ISR database to determine whether data for the specific engine models is available and will provide additional justification for the selected ratio(s).*

5. Page 19: the protocol shows that the wind-blown fugitive dust emissions and sources will be modeled as area sources with a release height of 0.5 meters. Per South Coast Air Quality Management District's request for Redondo Beach and Huntington Beach projects, fugitive dust emissions should be modeled as a ground-level area source with an initial vertical dimension of 1 meter. Please use assumptions consistent with those used for the recent siting cases.

   We will follow CEC staff's recommendation for modeling wind-blown fugitive dust emission sources as ground-level area sources with an initial vertical dimension of 1 meter.

6. Page 19: the protocol states that for the construction modeling analysis, the receptor grid will begin at the property boundary and will extend approximately one kilometer in all directions. Although staff does not expect maximum construction impacts to occur far away from the project, staff has been using receptor grids extending 6 miles (10 kilometers). If one kilometer radius is used, please demonstrate maximum construction impacts do not occur beyond one kilometer radius.

   We agree with CEC staff that it is unlikely that maximum construction impacts will occur more than one kilometer away from the project boundary. However, we will make the requested demonstration to ensure that the maximum impacts are captured in our modeling analysis.

<u>Public Health (CEC staff comments dated September 23, 2014)</u>

1. P. 9 Receptor Grids

   Other than grid receptors, please also place receptors at:

   a. All sensitive locations (e.g., child care facilities, schools, hospitals, prisons, libraries, etc.) out to 1-mile, if any are identified.

   b. The nearest residences and off-site workers.

   Please also provide the excel file containing the information (i.e. HARP Receptor #, UTM Meters, Description,...) of these sensitive receptors.

   We will place additional receptors at the locations of any identified sensitive receptors, as well as at the locations of the nearest residences and off-site workers.

The requested Excel file summary of sensitive receptor numbers, locations and descriptions will also be provided as requested.

2. P.18 Health Risk Assessment

   If OEHHA/CARB updates the guidance and HARP before the file of AFC, please conduct the HRA according to the new guidance and by using software. The updated OEHHA guidance regarding **inhalation rate** and **age sensitivity factors** would increase the estimated risk at least 3 times more than the old method.

   As indicated in the protocol, OEHHA is currently in the process of revising its "Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments," and CARB is in the process of updating the Hotspots Analysis and Reporting Program (HARP) software to implement the updated OEHHA guidance; however, it is not clear when either revision will be released publicly. If an updated version of HARP is made available on ARB's website before the AFC is filed, we will use that updated version of HARP for preparing the screening health risk assessment.

Appendix 3.1F
Ambient Air Quality Analysis Modeling Inputs and Screening Analysis

APPENDIX 3.1F

Dispersion modeling was conducted following the modeling protocol presented in Appendix 3.1-E. In response to comments received from the CEC Staff, the modeling analysis deviated from the protocol as follows:

- The latest version of SCREEN3, version 13043, was used.
- The paired-sum approach was not used for demonstrating compliance with the federal one-hour NO_2 standard.
- The maximum modeled annual average $PM_{2.5}$ concentrations were used to demonstrate compliance with the annual standard, consistent with the form of the standard.
- An NO_2:NOx ratio of 20% was used in modeling NO_2 impacts from the diesel fire pump engine.
- An NO_2:NOx ratio of 11% was used in modeling NO_2 impacts from diesel-powered construction equipment.
- Wind-blown fugitive dust sources were modeled as ground-level area sources with an initial vertical dimension of 1 meter.
- The initial construction impact receptor grid extended 6 miles (10 km) from…

Modeling input and output files, including meteorological data files, are provided on CD.

Table 3.1F-1
Sonoran Energy Project
Screening Modeling Inputs

e		Ambient Temp deg F	Stack Height feet	Stack Diam feet	Stack Flow wacfm	Stack Velocity ft/sec	Stack Temp deg F	Stack Height meters	Stack Diam meters	Stack Flow m3/sec	Stack Velocity m/sec	Stack Temp deg K
1.	Hot 100% Load DF w/Evap Cooling	110	140	22.0	1,649,006	72.30	163.0	42.67	6.71	778.35	22.04	345.93
2.	Hot 100% Load no DF w/Evap Cooling	110	140	22.0	1,683,859	73.83	175.7	42.67	6.71	794.80	22.50	352.98
3.	Hot Min Load no Evap Cooling	110	140	22.0	1,157,393	50.75	164.9	42.67	6.71	546.30	15.47	347.00
4.	Avg 100% Load DF w/Evap Cooling	74	140	22.0	1,592,154	69.81	157.8	42.67	6.71	751.51	21.28	343.06
5.	Avg 100% Load no DF w/Evap Cooling	74	140	22.0	1,619,012	70.98	167.8	42.67	6.71	764.19	21.64	348.61
6.	Avg. Min Load no Evap Cooling	74	140	22.0	996,643	43.70	153.4	42.67	6.71	470.43	13.32	340.57
7.	ISO 100% Load w/ DF, w/ Evap Cooling	59	140	22.0	1,601,071	70.20	157.4	42.67	6.71	755.72	21.40	342.81
8.	ISO 100% Load w/ DF, no Evap Cooling	59	140	22.0	1,578,292	69.20	156.8	42.67	6.71	744.97	21.09	342.46
9.	Cold 100% Load w/ DF	39	140	22.0	1,637,212	71.78	154.9	42.67	6.71	772.78	21.88	341.44
10.	Cold 100% Load no DF	39	140	22.0	1,660,498	72.80	163.3	42.67	6.71	783.77	22.19	346.08
11.	Cold Min Load	39	140	22.0	972,774	42.65	149.9	42.67	6.71	459.16	13.00	338.63
		NOx lb/hr	**CO lb/hr**	**PM10 lb/hr**	**SOx lb/hr**			**NOx g/sec**	**CO g/sec**	**PM10 g/sec**	**SOx g/sec**	
1.	Hot 100% Load DF w/Evap Cooling	25.20	15.30	10.00	4.75			3.175	1.928	1.260	0.599	
2.	Hot 100% Load no DF w/Evap Cooling	23.40	14.30	8.00	4.44			2.948	1.802	1.008	0.560	
3.	Hot Min Load no Evap Cooling	14.40	8.75	8.00	2.73			1.814	1.103	1.008	0.344	
4.	Avg 100% Load DF w/Evap Cooling	25.00	15.20	10.00	4.72			3.150	1.915	1.260	0.595	
5.	Avg 100% Load no DF w/Evap Cooling	23.30	14.20	8.00	4.41			2.936	1.789	1.008	0.556	
6.	Avg. Min Load no Evap Cooling	12.80	7.80	8.00	2.43			1.613	0.983	1.008	0.306	
7.	ISO 100% Load w/ DF, w/ Evap Cooling	25.30	15.40	10.00	4.78			3.188	1.940	1.260	0.602	
8.	ISO 100% Load w/ DF, no Evap Cooling	24.90	15.10	10.00	4.70			3.137	1.903	1.260	0.592	
9.	Cold 100% Load w/ DF	26.00	15.80	10.00	4.91			3.276	1.991	1.260	0.618	
10.	Cold 100% Load no DF	24.20	14.80	8.00	4.60			3.049	1.865	1.008	0.580	
11.	Cold Min Load	12.90	7.83	8.00	2.44			1.625	0.987	1.008	0.308	

Table 3.1F-2
Sonoran Energy Project
Screening Modeling Results

Operating Mode	Maximum Modeled Unit Impact (ug/m3 per g/s)					
	1-hr	3-hr	8-hr	24-hr	Annual	
1. Hot 100% Load DF w/Evap Cooling	4.39	2.24	1.17	0.57	0.07	
2. Hot 100% Load no DF w/Evap Cooling	4.07	2.07	1.09	0.52	0.06	
3. Hot Min Load no Evap Cooling	5.11	2.61	1.61	0.87	n/a	
4. Avg 100% Load DF w/Evap Cooling	4.59	2.33	1.21	0.62	0.07	
5. Avg 100% Load no DF w/Evap Cooling	4.33	2.20	1.16	0.57	0.06	
6. Avg. Min Load no Evap Cooling	6.36	2.99	2.04	1.09	n/a	
7. ISO 100% Load w/ DF, w/ Evap Cooling	4.59	2.33	1.20	0.61	0.07	
8. ISO 100% Load w/ DF, no Evap Cooling	4.65	2.34	1.21	0.63	0.07	
9. Cold 100% Load w/ DF	4.62	2.34	1.20	0.60	0.07	
10. Cold 100% Load no DF	4.37	2.23	1.16	0.56	0.06	
11. Cold Min Load	6.68	3.09	2.16	1.14	0.12	Max Min-Load Impact for Startup/Shutdown

Table 3.1F-2 (cont'd)
Screening Modeling Results

Operating Mode	Maximum Modeled Concentration (ug/m3)						
	NOx	CO	SO2	SO2	CO	PM10	SO2
	1-hr	1-hr	1-hr	3-hr	8-hr	24-hr	24-hr
1. Hot 100% Load DF w/Evap Cooling	13.92	8.45	2.63	1.34	2.25	0.72	0.342
2. Hot 100% Load no DF w/Evap Cooling	12.01	7.34	2.28	1.16	1.96	0.52	0.289
3. Hot Min Load no Evap Cooling	9.27	5.63	1.76	0.90	1.78	0.88	0.300
4. Avg 100% Load DF w/Evap Cooling	14.46	8.79	2.73	1.38	2.31	0.78	0.366
5. Avg 100% Load no DF w/Evap Cooling	12.70	7.74	2.41	1.23	2.07	0.57	0.316
6. Avg. Min Load no Evap Cooling	10.25	6.25	1.95	0.92	2.01	1.10	0.333
7. ISO 100% Load w/ DF, w/ Evap Cooling	14.64	8.91	2.76	1.40	2.34	0.77	0.369
8. ISO 100% Load w/ DF, no Evap Cooling	14.60	8.85	2.76	1.39	2.31	0.79	0.371
9. Cold 100% Load w/ DF	**15.13**	**9.19**	**2.86**	**1.44**	**2.40**	0.76	**0.374**
10. Cold 100% Load no DF	13.32	8.15	2.53	1.29	2.17	0.57	0.327
11. Cold Min Load	10.86	6.59	2.06	0.95	2.13	**1.15**	0.351
Maximum, All Cases	15.13	9.19	2.86	1.44	2.40	1.15	0.374

Table 3.1F-3
Sonoran Energy Project
Emission Rates and Stack Parameters for Refined Modeling

	Stack Height, m	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s NOx	SO2	CO	PM10
Averaging Period: One hour									
Gas Turbine	42.672	6.706	341.443	772.678	21.879	3.2760	0.6182	1.9908	n/a
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	0.0703	1.151E-02	0.3056	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	0.0846	1.548E-04	1.983E-02	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: Three hours									
Gas Turbine	42.672	6.706	341.443	772.678	21.879	n/a	0.6182	n/a	n/a
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	1.151E-02	n/a	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	5.160E-05	n/a	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: Eight hours									
Gas Turbine	42.672	6.706	341.443	772.678	21.879	n/a	n/a	5.967	n/a
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	n/a	0.6112	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	n/a	2.479E-03	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: 24-hour SOx									
Gas Turbine	42.672	6.706	341.443	772.678	21.879	n/a	0.6182	n/a	n/a
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	1.151E-02	n/a	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	6.450E-06	n/a	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: 24-hour PM10									
Gas Turbine	42.672	6.706	338.631	459.098	13.000	n/a	n/a	n/a	1.0080
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	n/a	n/a	5.844E-02
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	n/a	n/a	2.204E-04
Cooling Tower (each cell)	12.754	8.534	299.261	641.424	11.213	n/a	n/a	n/a	2.042E-02
Averaging Period: Annual NOx and SOx									
Gas Turbine	42.672	6.706	341.443	772.678	21.879	2.3932	0.2490	n/a	n/a
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	6.440E-02	4.60E-03	n/a	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	3.86E-03	7.07E-06	n/a	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: Annual PM10									
Gas Turbine	42.672	6.706	342.460	744.871	21.092	n/a	n/a	n/a	0.9032
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	n/a	n/a	4.670E-02
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	n/a	n/a	1.208E-04
Cooling Tower (each cell)	12.754	8.534	299.261	641.424	11.213	n/a	n/a	n/a	2.042E-02

Table 3.1F-4
Sonoran Energy Project
Emission Rates and Stack Parameters for Startup Modeling: Gas Turbine and Auxiliary Boiler

	Stack Height, m	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s			
						NOx	SO2	CO	PM10
Averaging Period: One hour									
Gas Turbine	42.672	6.706	338.631	459.098	13.000	23.625	0.308	17.130	n/a
Auxiliary Boiler	15.240	0.889	522.039	5.803	9.349	0.2509	1.151E-02	1.528	n/a
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	0.085	1.548E-04	1.983E-02	n/a
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 3.1F-5
Sonoran Energy Project
Emission Rates and Stack Parameters for Commissioning Modeling: Gas Turbine and Auxiliary Boiler

Auxiliary Boiler

	Stack Height, m	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s	
						NOx	CO
Averaging Period: One hour, three hours, eight hours							
Auxiliary Boiler	15.240	0.889	522.039	5.803	9.349	1.0038	1.5279

Gas Turbine

	Stack Height, m	Stack Diam, m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s	
						NOx	CO
Averaging Period: One hour							
Gas Turbine	42.672	6.706	338.631	459.098	13.000	78.692	619.831
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	0.0703	0.306
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	0.000	0.0000
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Averaging Period: Eight hours							
Gas Turbine	42.672	6.706	338.631	459.098	13.000	n/a	448.513
Auxiliary Boiler	15.240	0.889	588.706	13.441	21.655	n/a	0.306
Emergency Firepump	3.048	0.154	726.483	0.714	38.310	n/a	0.0000
Cooling Tower	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table 5.1F-6
Sonoran Energy Project
SCREEN 3 Fumigation Modeling

Case	Emission Rates, g/s NOx	CO	PM10	SO2
1. Hot 100% Load DF w/Evap Cooling	3.18	1.93	1.26	0.60
2. Hot 100% Load no DF w/Evap Cooling	2.95	1.80	1.01	0.56
3. Hot Min Load no Evap Cooling	1.81	1.10	1.01	0.34
4. Avg 100% Load DF w/Evap Cooling	3.15	1.92	1.26	0.59
5. Avg 100% Load no DF w/Evap Cooling	2.94	1.79	1.01	0.56
6. Avg. Min Load no Evap Cooling	1.61	0.98	1.01	0.31
7. ISO 100% Load w/ DF, w/ Evap Cooling	3.19	1.94	1.26	0.60
8. ISO 100% Load w/ DF, no Evap Cooling	3.14	1.90	1.26	0.59
9. Cold 100% Load w/ DF	3.28	1.99	1.26	0.62
10. Cold 100% Load no DF	3.05	1.86	1.01	0.58
11. Cold Min Load	1.63	0.99	1.01	0.31
Aux Boiler	0.0703	0.306	0.0584	0.0115

	Unit	Emissions, ug/m3				Distance to
Inversion Breakup	Impacts	NOx	CO	PM10	SO2	Maxima (m)
1. Hot 100% Load DF w/Evap Cooling	1.067	3.39	2.06	1.34	0.64	18,009
2. Hot 100% Load no DF w/Evap Cooling	0.984	2.90	1.77	0.99	0.55	19,116
3. Hot Min Load no Evap Cooling	1.319	2.39	1.45	1.33	0.45	15,399
4. Avg 100% Load DF w/Evap Cooling	1.124	3.54	2.15	1.42	0.67	17,325
5. Avg 100% Load no DF w/Evap Cooling	1.319	3.87	2.36	1.33	0.73	15,399
6. Avg. Min Load no Evap Cooling	1.561	2.52	1.53	1.57	0.48	13,603
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.124	1.81	1.10	1.13	0.34	17,335
8. ISO 100% Load w/ DF, no Evap Cooling	1.141	1.84	1.12	1.15	0.35	17,143
9. Cold 100% Load w/ DF	1.125	1.81	1.11	1.13	0.34	17,323
10. Cold 100% Load no DF	1.060	1.71	1.04	1.07	0.32	18,089
11. Cold Min Load	1.624	2.62	1.60	1.64	0.50	13,212
Aux Boiler	12.58	20.29	12.36	12.68	3.86	2,972

Table 3.1F-6 (cont'd)
SCREEN 3 Fumigation Modeling Results

Flat Terrain	Unit Impacts	Emissions, ug/m3 NOx	CO	PM10	SO2	Distance to Maxima (m)
1. Hot 100% Load DF w/Evap Cooling	0.956	3.04	1.84	1.20	0.57	1,084
2. Hot 100% Load no DF w/Evap Cooling	0.855	2.52	1.54	0.86	0.48	1,121
3. Hot Min Load no Evap Cooling	1.082	1.96	1.19	1.09	0.37	1,157
4. Avg 100% Load DF w/Evap Cooling	0.992	3.12	1.90	1.25	0.59	1,074
5. Avg 100% Load no DF w/Evap Cooling	1.082	3.18	1.94	1.09	0.60	1,157
6. Avg. Min Load no Evap Cooling	1.374	2.22	1.35	1.38	0.42	1,075
7. ISO 100% Load w/ DF, w/ Evap Cooling	0.992	1.60	0.97	1.00	0.30	1,074
8. ISO 100% Load w/ DF, no Evap Cooling	0.994	1.60	0.98	1.00	0.30	1,074
9. Cold 100% Load w/ DF	0.992	1.60	0.97	1.00	0.30	1,074
10. Cold 100% Load no DF	0.948	1.53	0.93	0.96	0.29	1,087
11. Cold Min Load	1.452	2.34	1.43	1.46	0.44	1,057
Aux Boiler	10.780	17.39	10.59	10.87	3.30	362

Appropriate 1-hr unit impacts to use for longer averaging periods

	Unit Impact for Avg Period, ug/m3 per g/s 1 hour	3 hours	8 hours	24 hours
1. Hot 100% Load DF w/Evap Cooling	1.07	1.01	0.98	0.96
2. Hot 100% Load no DF w/Evap Cooling	0.98	0.92	0.88	0.86
3. Hot Min Load no Evap Cooling	1.32	1.20	1.13	1.10
4. Avg 100% Load DF w/Evap Cooling	1.12	1.06	1.02	1.00
5. Avg 100% Load no DF w/Evap Cooling	1.32	1.20	1.13	1.10
6. Avg. Min Load no Evap Cooling	1.56	1.47	1.41	1.39
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.12	1.06	1.02	1.00
8. ISO 100% Load w/ DF, no Evap Cooling	1.14	1.07	1.02	1.00
9. Cold 100% Load w/ DF	1.13	1.06	1.02	1.00
10. Cold 100% Load no DF	1.06	1.00	0.97	0.96
11. Cold Min Load	1.62	1.54	1.48	1.46
Aux Boiler	12.58	11.68	11.12	10.89

Table 3.1F-6 (cont'd)
SCREEN 3 Fumigation Modeling Results

	Unit	Emissions, ug/m3			
1-hr average	Impacts	NOx	CO	PM10	SO2
1. Hot 100% Load DF w/Evap Cooling	1.07	3.4	2.1	-	0.64
2. Hot 100% Load no DF w/Evap Cooling	0.98	2.9	1.8	-	0.55
3. Hot Min Load no Evap Cooling	1.32	2.4	1.5	-	0.45
4. Avg 100% Load DF w/Evap Cooling	1.12	3.5	2.2	-	0.67
5. Avg 100% Load no DF w/Evap Cooling	1.32	3.9	2.4	-	0.73
6. Avg. Min Load no Evap Cooling	1.56	2.5	1.5	-	0.48
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.12	3.6	2.2	-	0.68
8. ISO 100% Load w/ DF, no Evap Cooling	1.14	3.6	2.2	-	0.68
9. Cold 100% Load w/ DF	1.13	**3.7**	**2.2**	-	**0.70**
10. Cold 100% Load no DF	1.06	3.2	2.0	-	0.61
11. Cold Min Load	1.62	2.6	1.6	-	0.50
Aux Boiler	12.58	0.9	3.8	-	0.14
3-hr average					
1. Hot 100% Load DF w/Evap Cooling	1.01	-	-	-	0.55
2. Hot 100% Load no DF w/Evap Cooling	0.92	-	-	-	0.46
3. Hot Min Load no Evap Cooling	1.20	-	-	-	0.37
4. Avg 100% Load DF w/Evap Cooling	1.06	-	-	-	0.57
5. Avg 100% Load no DF w/Evap Cooling	1.20	-	-	-	0.60
6. Avg. Min Load no Evap Cooling	1.47	-	-	-	0.40
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.06	-	-	-	0.57
8. ISO 100% Load w/ DF, no Evap Cooling	1.07	-	-	-	0.57
9. Cold 100% Load w/ DF	1.06	-	-	-	**0.59**
10. Cold 100% Load no DF	1.00	-	-	-	0.52
11. Cold Min Load	1.54	-	-	-	0.43
Aux Boiler	11.68	-	-	-	0.12
8-hr average					
1. Hot 100% Load DF w/Evap Cooling	0.98	-	1.3	-	-
2. Hot 100% Load no DF w/Evap Cooling	0.88	-	1.1	-	-
3. Hot Min Load no Evap Cooling	1.13	-	0.9	-	-
4. Avg 100% Load DF w/Evap Cooling	1.02	-	1.4	-	-
5. Avg 100% Load no DF w/Evap Cooling	1.13	-	1.4	-	-
6. Avg. Min Load no Evap Cooling	1.41	-	1.0	-	-
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.02	-	1.4	-	-
8. ISO 100% Load w/ DF, no Evap Cooling	1.02	-	1.4	-	-
9. Cold 100% Load w/ DF	1.02	-	**1.4**	-	-
10. Cold 100% Load no DF	0.97	-	1.3	-	-
11. Cold Min Load	1.48	-	1.0	-	-
Aux Boiler	11.12	-	2.4	-	-
24-hr average					
1. Hot 100% Load DF w/Evap Cooling	0.96	-	-	0.49	0.23
2. Hot 100% Load no DF w/Evap Cooling	0.86	-	-	0.35	0.19
3. Hot Min Load no Evap Cooling	1.10	-	-	0.44	0.15
4. Avg 100% Load DF w/Evap Cooling	1.00	-	-	0.50	0.24
5. Avg 100% Load no DF w/Evap Cooling	1.10	-	-	0.44	0.24
6. Avg. Min Load no Evap Cooling	1.39	-	-	**0.56**	0.17
7. ISO 100% Load w/ DF, w/ Evap Cooling	1.00	-	-	0.50	0.24
8. ISO 100% Load w/ DF, no Evap Cooling	1.00	-	-	0.51	0.24
9. Cold 100% Load w/ DF	1.00	-	-	0.50	**0.25**
10. Cold 100% Load no DF	0.96	-	-	0.39	0.22
11. Cold Min Load	1.46	-	-	0.03	0.01
Aux Boiler	10.89	-	-	0.25	0.05

Table 5.1F-7
Sonoran Energy Project
Emission Rates and Stack Parameters for Modeling Existing BEP

	Stack Height, m	Stack Diam, m	Temp, deg K	Exhaust Velocity, m/s	Emission Rates, g/s			
					NOx	SO2	CO	PM10
Averaging Period: One, 3, 8 and 24 hours								
Gas turbines (each)	39.62	5.639	350.15	18.08	2.4948	0.3402	2.2050	0.7836
Main cooling tower (each of 8 cells)	11.89	8.534	307.90	6.64	n/a	n/a	n/a	8.033E-03
Chiller cooling tower (each of 12 cells)	8.53	4.877	307.90	8.20	n/a	n/a	n/a	3.780E-04
Averaging Period: Annual								
Gas turbines (each)	39.62	5.639	350.15	18.08	1.3952	0.1726	n/a	0.7836
Main cooling tower (each of 8 cells)	11.89	8.534	307.90	6.64	n/a	n/a	n/a	8.033E-03
Chiller cooling tower (each of 12 cells)	8.53	4.877	307.90	8.20	n/a	n/a	n/a	3.780E-04

Figure 3.1F-1
SEP Building Layout for Modeling

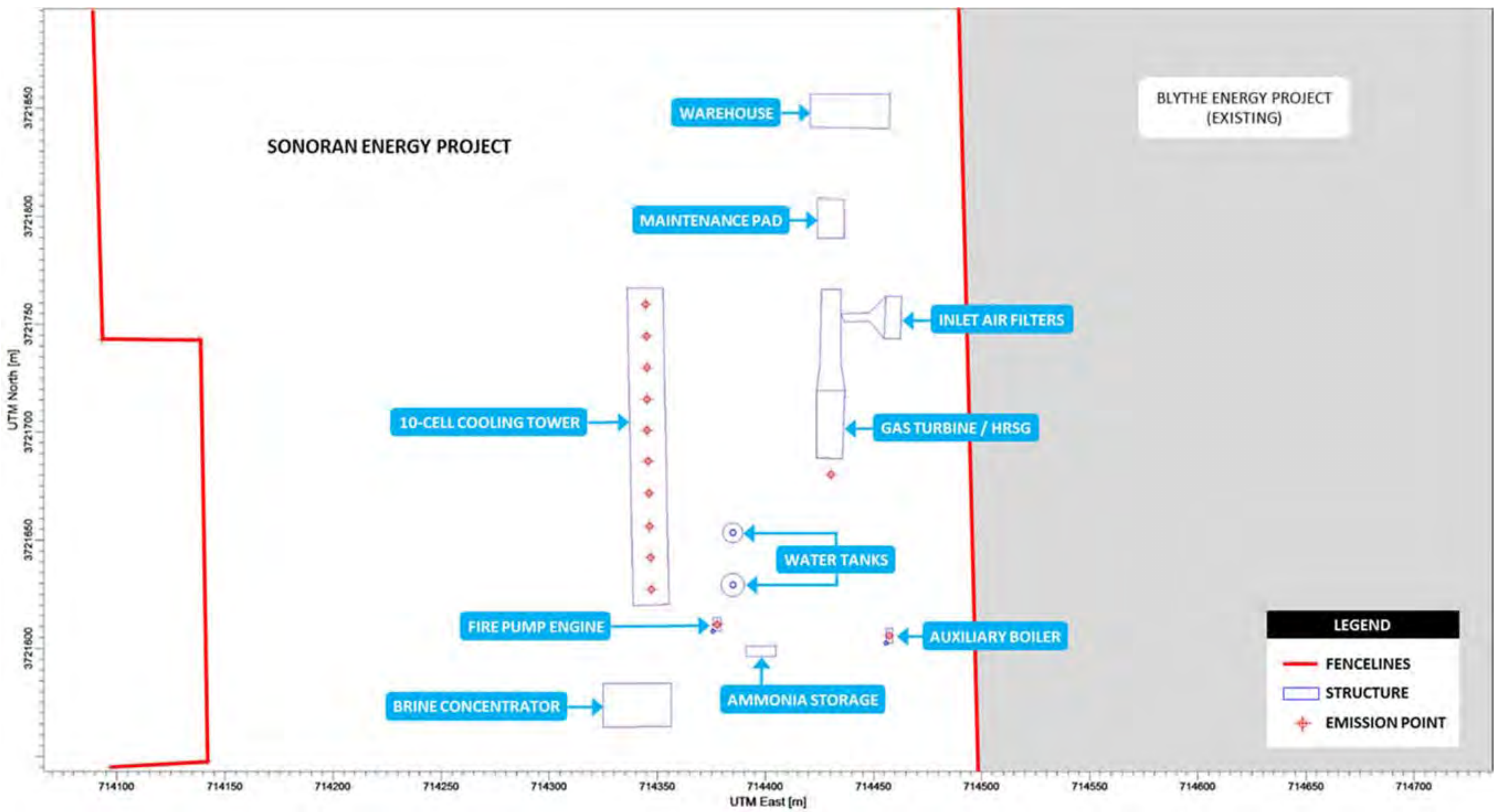

Figure 3.1F-2
SEP and BEP Site Locations for Modeling

Appendix 3.1G
Cumulative Impact Analysis

APPENDIX 3.1G

Cumulative Impacts Analysis

Cumulative air quality impacts from SEP and other reasonably foreseeable projects will be both regional and localized in nature. Regional air quality impacts are possible for pollutants such as ozone and $PM_{2.5}$ which are formed through photochemical processes that can take hours to occur. Carbon monoxide, NOx, and SOx impacts are generally localized in the area in which they are emitted. PM_{10} can create a local air quality problem in the vicinity of its emission source, but can also be a regional issue when it is formed in the atmosphere from VOC, SOx, and NOx.

The cumulative impacts analysis considers the potential for both regional and localized impacts due to emissions from proposed operation of SEP. Regional impacts are evaluated by comparing maximum daily and annual emissions from the project with emissions of ozone and PM precursors in the Mojave Desert Air Basin. Localized impacts are evaluated by looking at other local sources of pollutants that are not included in the background air quality data to determine whether these sources in combination with SEP would be expected to cause significant cumulative air quality impacts.

Regional Impacts

Regional impacts are normally evaluated by assessing the project's contribution to regional emissions. Although the relative importance of VOC and NOx emissions in ozone formation differs from region to region and from day to day, state law requires reductions in emissions of both precursors to reduce overall ozone levels. The change in the sum of emissions of these pollutants, equally weighted, is used to provide a rough estimate of the impact of the project on regional ozone levels. However, because of the rural and relatively undeveloped nature of the project area (eastern Riverside County), the MDAQMD and ARB have determined that ozone concentrations in the area largely reflect the impact of transport from the South Coast Air Basin and the San Joaquin Valley Air Basin.[1] Therefore, in this instance a comparison of project emissions with emissions in the air basin is not particularly informative because regional air quality is not correlated with local or regional sources of emissions. However, this also suggests that the project emissions will have minimal impact on local ozone levels because the majority of ozone in the project area comes from outside the air basin.

A comparison of the emissions of PM_{10} and $PM_{2.5}$ precursor emissions from the project with regional PM_{10} and $PM_{2.5}$ precursor emissions can be used to provide an estimate of the impact of the Project on regional PM_{10} and $PM_{2.5}$ levels. As discussed above, emissions of NOx and VOC, which are PM_{10}/$PM_{2.5}$ precursors as well as ozone precursors, are relatively low. The majority of regional PM_{10} and $PM_{2.5}$ comes from directly emitted particulate matter in the form of unpaved road dust and fugitive windblown dust.

1 MDAQMD, "2004 Ozone Attainment Plan (State and Federal). April 2004.

Table 3.1G-1 summarizes these comparisons. Project emissions are compared with projected regional emissions in 2020. Projected emissions for the MDAQMD for 2020 were obtained using CARB's web-based emission inventory projection software.[2] Emissions from the project would result in very small increases in total emissions in the county. Because of the relatively small emissions contribution from the project, including the benefits of required mitigation, and because regional air quality is heavily influenced by transport, we expect that the overall impact of the project on regional air quality will not be significant.

TABLE 3.1G-1
Comparison of Project Emissions to Regional Precursor Emissions in 2020: Annual Basis[a]

Ozone Precursors – Annual Basis	
Total Regional Ozone Precursors, tons/year	51,729
Total Project Ozone Precursor Emission, tons/year	109.8
Project Emissions as Percentage of Regional Ozone Precursor Emissions	0.21%
PM_{10} Precursors – Annual Basis	
Total Regional PM_{10} Precursors, tons/year	88,591
Total Project PM_{10} Precursor Emissions, tons/year	158.7
Project Emissions as Percentage of Regional PM_{10} Precursor Emissions	0.18%
$PM_{2.5}$ Precursors – Annual Basis	
Total Regional $PM_{2.5}$ Precursors, tons/year	62,541
Total Project $PM_{2.5}$ Precursor Emissions, tons/year	158.7
Project Emissions as Percentage of Regional $PM_{2.5}$ Precursor Emissions	0.25%

[a] Basin-wide emissions calculated as 365 times daily emissions

Localized Impacts

To evaluate potential cumulative impacts of the project in combination with other projects in the area, we requested from the MDAQMD information regarding projects within a radius of 10 km (6 miles) of the project.

Within this search area, two types of projects were used as criteria for identification:

- Projects for which air pollution permits to construct have been issued since August 1, 2012; and
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

As requested by the District, the cumulative impacts analysis will also include the operational Blythe Energy Project, to ensure that localized impacts are evaluated.

A copy of the information request to the District for information about potential projects in the vicinity is attached. Since the proposed SEP will replace the licensed Blythe II project, Blythe II is not included in the cumulative impacts analysis.

[2] http://www.arb.ca.gov/app/emsinv/fcemssumcat2013.php, accessed April 2015.

Additional planned development projects include the Blythe Mesa Solar Project, the Blythe Solar Power Project (formerly Palo Verde Solar I), the Blythe Solar Power Generation Station 1, and the Blythe Airport Solar I Project.

The Blythe Mesa Solar Project is proposed for construction in areas generally north, east and south of the SEP site. The Environmental Impact Report/Environmental Assessment prepared for the project determined that emissions from project construction and operation will be below MDAQMD CEQA thresholds for all pollutants. Construction is expected to take 3 years. Although some of the construction activities for the Blythe Mesa project may occur concurrently with some of the construction activities at SEP, impacts during construction are expected to be highly localized. The Blythe Mesa Solar Project EIR evaluated the construction of that project in combination with the construction of the Blythe Energy II project and determined that the potential cumulative impacts would not be significant.[3] Because the construction of SEP will be similar in scope and schedule to the construction of the BEP II project evaluated in the EIR, the conclusion is equally applicable for potential cumulative impacts with SEP.

The Blythe Solar Power Project will be constructed approximately 6 miles north of the SEP site. Because the project is a photovoltaic project, it is unlikely to have any operational air quality impacts. According to the staff assessment prepared by the CEC for the project,[4] construction is likely to take approximately 48 months. However, even if the project construction schedule were to coincide with SEP project construction, the localized construction impacts are unlikely to cause any cumulative impacts with SEP due to the distance between the project construction sites.

The BEP II Staff Analysis evaluated the potential for BEP II to have significant cumulative impacts on ozone and particulate matter concentrations in the project area. The SA concluded that the BEP II and cumulative sources would not create any new violations of NO_2 standards.

The SA also concluded that with implementation of staff-recommended construction and operation CEQA mitigation measures, it is unlikely that the BEP II would have significant impacts on ambient PM concentrations. The PM emissions from the proposed SEP are lower than those from the licensed BEP II, and the modeled impacts are similar. Further, the staff-recommended construction mitigation measures will be implemented for SEP, along with appropriate mitigation measures for project operation. Therefore, the project owner believes that the previous conclusions regarding significant impacts from BEP II are also applicable to SEP.

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3 Riverside County Planning Department and U.S. BLM, "Blythe Mesa Solar Project, EIR/EA. Chapter 4: Environmental Consequences Including Cumulative Impacts," April 2015.

4 CEC, "Blythe Solar Power Project Staff Assessment - Part A (Corrected)," 09-AFC-06C. September 2013.

ATTACHMENT 3.1G-1

Correspondence Related To Cumulative Impacts Analysis

MOJAVE
air quality management district
DESERT

Mojave Desert Air Quality Management District
14306 Park Avenue, Victorville, CA 92392-2310
760.245.1661 • fax 760.245.2699
Visit our web site: http://www.mdaqmd.ca.gov
Eldon Heaston, Executive Director

September 18, 2014

Ms. Nancy Mathews
Sierra Research
1801 "J" Street
Sacramento, CA 95811

Subject: AltaGas Kananaskis Energy Project Modeling Protocol

Dear Ms. Mathews:

The Mojave Desert Air Quality Management (District) received the air quality modeling protocol for the proposed AltaGas Kananaskis Energy Project (KEP) simple-cycle power plant to be located near Blythe in Riverside County. The District approves of the submitted KEP modeling protocol with exception that KEP include all proposed equipment (equipment not exempt per District Rule 219) and add to the background ambient air quality data significant nearby sources within a 6 mile radius of the proposed site. Below is a list of significant projects for which the District has issued permits (or in the process of issuing permits) and are located within 6 miles of the proposed KEP project site. All significant projects located within the 6 mile radius are approved California Energy Commission (CEC) Projects. The list below provides for each project- name, address, and CEC docket number.

<u>Blythe Energy Project</u>; Hobsonway & Buck Boulevard, Blythe, California. CEC Docket number 99-AFC-8.

<u>Blythe Energy Project, Phase II</u>; BEPII site boundary is located on approximately a 76 acre site immediately adjacent to the operational Blythe Energy Project (BEPI). CEC Docket number 02-AFC-1.

Should you have any questions please contact Mr. Christian Anderson, (760) 245-1661 extension 1846.

Sincerely,

Christopher A. Collins

Supervising Air Quality Engineer

cja

Appendix 3.8A/B
Sensitive Receptor Information

Irish Energy Project
Irish Energy Project
Blythe, CA 92225

Inquiry Number: 4118446.1s
October 28, 2014

EDR Offsite Receptor Report

EDR® Environmental Data Resources Inc

6 Armstrong Road, 4th floor
Shelton, CT 06484
Toll Free: 800.352.0050
www.edrnet.com

FORM-ARB

TABLE OF CONTENTS

Thank you for your business
Please contact EDR at 1-800-352-0050
with any questions or comments.

EXECUTIVE SUMMARY

A search of available records was conducted by Environmental Data Resources, Inc. (EDR). The EDR Offsite Receptor Report provides information which may be used to comply with the Clean Air Act Risk Management Program 112-R. *"The rule requires that you estimate in the RMP residential populations within the circle defined by the endpoint for your worst-case and alternative release scenarios (i.e., the center of the circle is the point of release and the radius is the distance to the endpoint). In addition, you must report in the RMP whether certain types of public receptors and environmental receptors are within the circles."*

The address of the subject property, for which the search was intended, is:

IRISH ENERGY PROJECT
IRISH ENERGY PROJECT
BLYTHE, CA 92225

Distance Searched: 6.000 miles from subject property

RECEPTOR SUMMARY
An X indicates the presence of the receptor within the search radius.

Residential Population
Estimated population within search radius: 8800 persons.

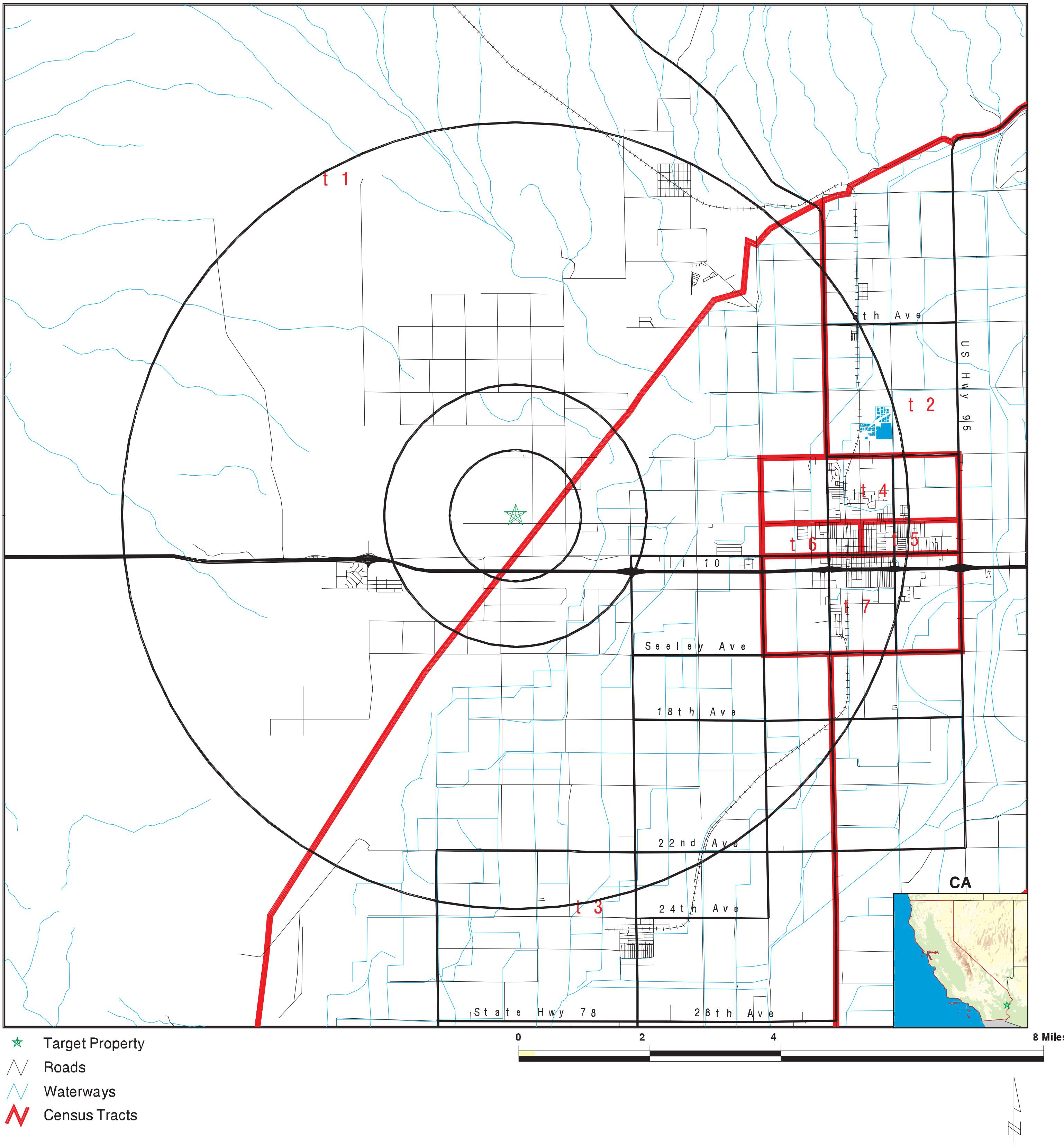
Other Public Receptors

Type	Within Search Radius	Sites Total
Day Care Centers:	X	14
Medical Centers:		
Nursing Homes:		
Schools:	X	7
Hospitals:	X	24
Colleges:	X	1
Arena:		
Prison:		

Environmental Receptors

Type	Within Search Radius	Sites Total
Federal Land:	X	4

CENSUS MAP - 4118446.1s

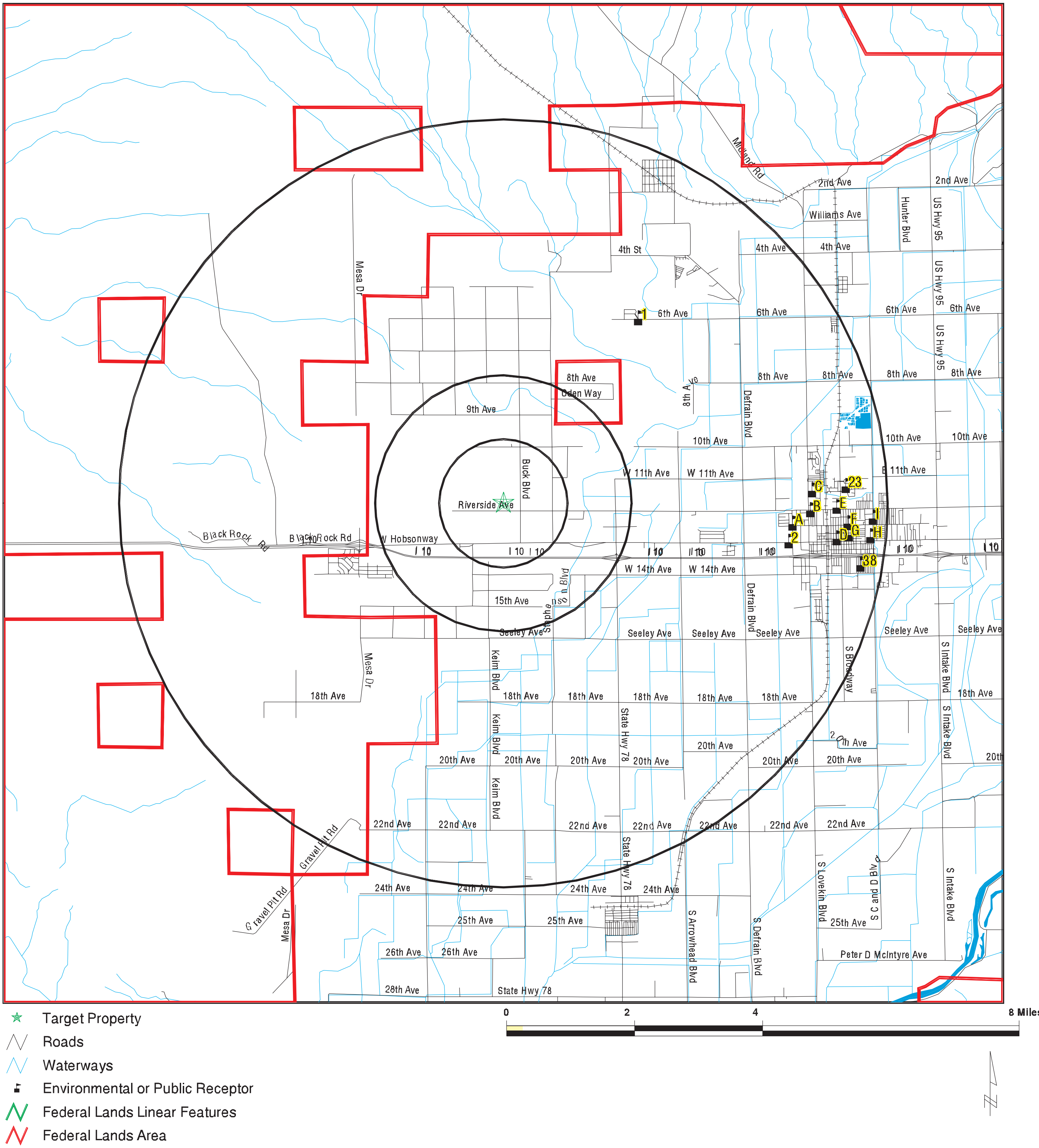


TARGET PROPERTY:	Irish Energy Project	CUSTOMER:	CH2M Hill, Inc.
ADDRESS:	Irish Energy Project	CONTACT:	Megan Grant
CITY/STATE/ZIP:	Blythe CA 92225	INQUIRY #:	4118446.1s
LAT/LONG:	33.6190 / 114.6883	DATE:	October 28, 2014 4:42 pm

CENSUS FINDINGS

Map ID	Tract Number	Total Population	Population in Radius	Total Area(sq.mi.)	Area in Radius(sq.mi.)
T1	0469.00	2043	32.8	3822.37	61.34
T2	0470.00	1749	87.0	53.76	2.67
T3	0459.00	1838	733.0	105.56	42.10
T4	0461.03	3030	2227.7	3.03	2.23
T5	0461.01	3060	1431.3	0.75	0.35
T6	0461.02	2027	2027.0	0.76	0.76
T7	0462.00	3341	2261.1	4.54	3.07

RECEPTOR MAP - 4118446.1s



TARGET PROPERTY:	Irish Energy Project	CUSTOMER:	CH2M Hill, Inc.
ADDRESS:	Irish Energy Project	CONTACT:	Megan Grant
CITY/STATE/ZIP:	Blythe CA 92225	INQUIRY #:	4118446.1s
LAT/LONG:	33.6190 / 114.6883	DATE:	October 28, 2014 4:43 pm

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
NA NNE 1-2 mi 7850 NA	Name: Feature: URL: Bureau: State: Is DOD?:	Not Reported Public Domain Land BLM Not Reported BLM CA No	CUSA144063 FED_LAND
NA SSW 2-4 mi 10893 NA	Name: Feature: URL: Bureau: State: Is DOD?:	Not Reported Public Domain Land BLM Not Reported BLM AZ-CA-NV-UT No	CUSA120946 FED_LAND
1 NE 2-4 mi 18817 Higher	Unitid: Instnm: Addr: City: Stabbr: Zip: Zip4: Unk: Fips: Oberge: Chfnm: Chftitle: Gentele: Fintele: Admtele: Ein: Duns: Opeid: Opeflag: Webaddr: Sector: Iclevel: Control: Hloffer: Ugoffer: Groffer: Fpoffer: Hdegoffer: Deggrant: Hbcu: Hospital: Medical: Tribal: Carnegie: Locale: Openpubl: Act:	120953 PALO VERDE COLLEGE ONE COLLEGE DRIVE BLYTHE CA 92225 Not Reported Not Reported 092225 8 James Hottois SUPT/PRESIDENT 7609215500 7609215500 7609215500 330833195 76051663 125900 1 www.paloverde.edu 4 2 1 3 1 2 2 40 1 2 2 2 2 40 3 1 A	SRCL20051000408 Colleges

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Newid:	-2	
	Deathyr:	-2	
	Closedat:	-2	
	Cyactive:	1	
	Postsec:	1	
	Pseflag:	1	
	Pset4flg:	1	
	Rptmth:	1	
	Fte:	1550	
	Enrtot:	3507	
	Edr id:	SRCL20051000408	

2			SRHO20070150021
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
23728	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	A	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	20051128	
	Medicare/Medicaid:	1	
	Facility name:	KENNETH G LUCERO MD	
	Intermediary/Carrier:	00542	
	Medicaid number:	Not Reported	
	Partcipation date:	19970820	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0932438	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	M1	
	street address:	1273 WEST HOBSONWAY	
	Phone num:	7609213468	
	Termination reason:	00	
	Term Date:	20080326	
	Purpose of action:	2	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070150021	

MAP FINDINGS

Map ID / Direction / Distance / Distance (ft.) / Elevation	Site		EDR ID / Database
A3			SRDCCA200741231
East	EDR ID:	SRDCCA200741231	Daycare
4-6 mi	Facility number:	334812665	
23893	Facility name:	"ESCUELA DE LA RAZA UNIDA, INC., CHILD DEV. CTR. "	
Lower	Facility eval. code:	0775	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	830	
	Facility status code:	03	
	Address:	316 NORTH CARLTON	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	P. O. BOX 910	
	City:	BLYTHE	
	State:	CA	
	Zip:	92226	
	Facility investor:	"GARNICA, CARMELA F. "	
	Licensee type:	C	
	License effective date:	31014	
	License expiration date:	Not Reported	
	License issue date:	031014	
	Program type:	MAXIMUM CAPACITY 21 INFANTS AGES BIRTH THRU 24 MONTHS. HOURS OF OPERATOPERATION MONDAY - FRIDAY 6:30AM THRU 5:30PM.	
	Original app. received date:	030203	
	Facility closed date:	Not Reported	
	Mailing address:	137 NORTH BRAODWAY	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	CARMELA F. GARNICA	
	Facility capacity:	21	
	Type of clients served:	955	
	Facility phone:	7609222582	

Map ID / Direction / Distance / Distance (ft.) / Elevation	Site		EDR ID / Database
A4			SRDCCA200753503
East	EDR ID:	SRDCCA200753503	Daycare
4-6 mi	Facility number:	334812664	
23893	Facility name:	"ESCUELA DE LA RAZA UNIDA, INC. CHILD DEV. CTR. "	
Lower	Facility eval. code:	0775	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	850	
	Facility status code:	03	
	Address:	316 NORTH CARLTON	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	P. O. BOX 910	
	City:	BLYTHE	
	State:	CA	
	Zip:	92226	
	Facility investor:	"GARNICA, CARMELA F. "	
	Licensee type:	C	
	License effective date:	31014	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	License expiration date:	Not Reported	
	License issue date:	031014	
	Program type:	MAXIMUM OF 28 CHILDREN AGES 2 - KINDERGARTEN. HOURS OF OPERATION MONDAY - FRIDAY 6:30AM - 5:30PM.	
	Original app. received date:	030203	
	Facility closed date:	Not Reported	
	Mailing address:	137 NORTH BROADWAY	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	CARMELA F. GARNICA	
	Facility capacity:	28	
	Type of clients served:	950	
	Facility phone:	7609229080	

B5			SRPU20071010973
East	Ncessch:	062964004599	Public Schools
4-6 mi	Schname05:	FELIX J. APPLEBY ELEMENTARY	
25112	Mstreet05:	811 WEST CHANSLOR WAY	
Lower	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	2835	
	Member05:	533	
	Phone05:	(760) 922-7174	
	Locale05:	3	
	Type05:	1	
	Level05:	1	
	Gslo05:	KG	
	Gshi05:	05	
	Edr id:	SRPU20071010973	

C6			SRPU20071010976
East	Ncessch:	062964004602	Public Schools
4-6 mi	Schname05:	PALO VERDE HIGH	
25140	Mstreet05:	667 NORTH LOVEKIN BLVD.	
Lower	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	1136	
	Member05:	913	
	Phone05:	(760) 922-7148	
	Locale05:	3	
	Type05:	1	
	Level05:	3	
	Gslo05:	09	
	Gshi05:	12	
	Edr id:	SRPU20071010976	

C7			SRPU20071010974
East	Ncessch:	062964004600	Public Schools
4-6 mi	Schname05:	BLYTHE MIDDLE	
25169	Mstreet05:	825 NORTH LOVEKIN BLVD.	
Lower			

Map ID / Direction / Distance / Distance (ft.) / Elevation	Site		EDR ID / Database
	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	1129	
	Member05:	835	
	Phone05:	(760) 922-1300	
	Locale05:	3	
	Type05:	1	
	Level05:	2	
	Gslo05:	06	
	Gshi05:	08	
	Edr id:	SRPU20071010974	

B8			SRDCCA200704054
East	EDR ID:	SRDCCA200704054	Daycare
4-6 mi	Facility number:	330919916	
25520	Facility name:	COPELAND FAMILY DAY CARE	
Lower	Facility eval. code:	0555	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	810	
	Facility status code:	03	
	Address:	480 NORTH WILLOW	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	480 NORTH WILLOW	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Facility investor:	"COPELAND, MARY ANNE "	
	Licensee type:	A	
	License effective date:	930208	
	License expiration date:	Not Reported	
	License issue date:	930208	
	Program type:	"MAXIMUM CAPACITY: 12 CHILDREN, WITH NO MORE THAN 4 INFANTS, OR CAPACITY 14 CHILDREN WHEN 2 CHILDREN ARE AT LEAST 6 YEARS OF AGE WITH A MAXIMUM OF 3 INFANTS; PROPERTY OWNER/LANDLORD CONSENT IS REQUIRED "GUEST BEDROOM AND GARAGE	
	Original app. received date:	921117	
	Facility closed date:	Not Reported	
	Mailing address:	480 NORTH WILLOW	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	"COPELAND, MARY ANNE "	
	Facility capacity:	14	
	Type of clients served:	960	
	Facility phone:	7609224851	

C9			SRDCCO200704898
East	EDR ID:	SRDCCO200704898	Daycare
4-6 mi	Resource number:	32362	
26142	Facility type:	EFACB	
Lower			

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Provider name:	FLORES TERESA	
	Mailing street:	726 N EUCALYPTUS	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Mailing zip 4:	0000	
	Location street:	726 N EUCALYPTUS	
	Location city:	BLYTHE	
	Location zip:	92225	
	Location zip 4:	0000	
	Telephone:	Not Reported	
	Division county cde:	Not Reported	
	Total capacity:	0	

D10			SRHO20070159409
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27023	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	DARIN D LU MD	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20030827	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D1016399	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	322 WEST HOBSONWAY, SUITE #3	
	Phone num:	7609212157	
	Termination reason:	00	
	Term Date:	20070826	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070159409	

D11			SRHO20070150105
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27038	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	BLYTHE FAMILY HEALTH CLINIC	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19980522	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0946376	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	321 W HOBSONWAY	
	Phone num:	7609224981	
	Termination reason:	00	
	Term Date:	20080521	
	Purpose of action:	Not Reported	
	Provider control:	02	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070150105	

E12			SRHO20070004245
East	Hospital type:	02	AHA Hospitals
4-6 mi	Num of times COO:	02	
27062	Owner date:	19871101	
Lower	City:	BLYTHE	
	Has plan of corr:	1	
	Compliance status:	A	

MAP FINDINGS

Map ID
Direction
Distance
Distance (ft.)
Elevation **Site** **EDR ID** **Database**

SSA county code:	430
Cross ref number:	05A374
FMS survey date:	Not Reported
Current survey date:	19871208
Medicare/Medicaid:	1
Facility name:	BLYTHE NURSING CARE CENTER
Intermediary/Carrier:	Not Reported
Medicaid number:	Not Reported
Partcipation date:	19740331
Prior COO date:	19740331
Prior carrier:	Not Reported
Provider ID:	05A029
Record Status:	A
Region code:	09
Is Partial Record:	Not Reported
state abbrev:	CA
ssa state:	05
state region cd:	BER
street address:	285 W CHANSLOR WAY
Phone num:	6199228176
Termination reason:	01
Term Date:	19880416
Purpose of action:	2
Provider control:	03
Zip:	92225
Fips state:	06
Fips cnty:	065
SSA MSA:	488
SSA MSA size code:	B
Date accredited:	Not Reported
Accred expire date:	Not Reported
Accred Org:	Not Reported
Num beds:	0050
Num cert beds:	0050
Source:	US_HOSPITAL_POSOTHER
Edr id:	SRHO20070004245

E13			SRHO20070005246
East	Hospital type:	02	AHA Hospitals
4-6 mi	Num of times COO:	00	
27062	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	1	
	Compliance status:	A	
	SSA county code:	430	
	Cross ref number:	555383	
	FMS survey date:	Not Reported	
	Current survey date:	19880923	
	Medicare/Medicaid:	1	
	Facility name:	BLYTHE NURSING CARE CENTER	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19880516	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Provider ID:	05A374	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	BER	
	street address:	285 N CHANSLOR WAY	
	Phone num:	6199228176	
	Termination reason:	01	
	Term Date:	19890801	
	Purpose of action:	2	
	Provider control:	03	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0049	
	Num cert beds:	0049	
	Source:	US_HOSPITAL_POSOTHER	
	Edr id:	SRHO20070005246	

E14			SRHO20070144362
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27062	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	BLYTHE NURSING CARE CENTER	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19940829	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0890942	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	285 W CHANSLOR WAY	
	Phone num:	6199228176	
	Termination reason:	00	
	Term Date:	20080828	

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070144362	

D15			SRHO20070160940
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27761	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	FRANCISCO J TEJEDA MD MEDICAL CLINIC	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20050823	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D1044558	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	M1	
	street address:	144 W HOBSONWAY	
	Phone num:	7609220840	
	Termination reason:	00	
	Term Date:	20070822	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	

	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070160940	

E16			SRPU20071010978
East	Ncessch:	062964004604	Public Schools
4-6 mi	Schname05:	MARGARET WHITE ELEMENTARY	
27799	Mstreet05:	610 NORTH BROADWAY	
Lower	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	1331	
	Member05:	694	
	Phone05:	(760) 922-5159	
	Locale05:	3	
	Type05:	1	
	Level05:	1	
	Gslo05:	KG	
	Gshi05:	05	
	Edr id:	SRPU20071010978	

E17			SRHO20070158992
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27817	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	A	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	20060321	
	Medicare/Medicaid:	1	
	Facility name:	KEITH MARK GROSS MD INC	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20050624	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D1042333	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	M1	
	street address:	500 NORTH BROADWAY	
	Phone num:	7609213376	
	Termination reason:	00	
	Term Date:	20080320	
	Purpose of action:	1	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070158992	

E18			SRHO20070141583
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27817	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	LEON PETER Y CHUA MD	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19950411	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0724940	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	500 N BROADWAY ST, STE 17	
	Phone num:	6199222152	
	Termination reason:	00	
	Term Date:	20080831	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070141583	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
E19 East 4-6 mi 27817 Lower			SRHO20070145971 AHA Hospitals

Hospital type: 01
Num of times COO: 00
Owner date: Not Reported
City: BLYTHE
Has plan of corr: 1
Compliance status: A
SSA county code: 430
Cross ref number: Not Reported
FMS survey date: Not Reported
Current survey date: 19940825
Medicare/Medicaid: 1
Facility name: CARDIOPUL SERVS ART BLD GAS LABORATORY
Intermediary/Carrier: 00542
Medicaid number: Not Reported
Partcipation date: 19940602
Prior COO date: Not Reported
Prior carrier: Not Reported
Provider ID: 05D0886990
Record Status: A
Region code: 09
Is Partial Record: Not Reported
state abbrev: CA
ssa state: 05
state region cd: M1
street address: 500 NORTH BROADWAY STREET SUITE 10
Phone num: 6199222152
Termination reason: 04
Term Date: 19960911
Purpose of action: 1
Provider control: 04
Zip: 92225
Fips state: 06
Fips cnty: 065
SSA MSA: 488
SSA MSA size code: B
Date accredited: Not Reported
Accred expire date: Not Reported
Accred Org: Not Reported
Num beds: 0000
Num cert beds: 0000
Source: US_HOSPITAL_POSCLIA
Edr id: SRHO20070145971

D20 East 4-6 mi 27984 Lower			SRHO20070160710 AHA Hospitals

Hospital type: 01
Num of times COO: 00
Owner date: Not Reported
City: BLYTHE
Has plan of corr: Not Reported
Compliance status: Not Reported
SSA county code: 430
Cross ref number: Not Reported
FMS survey date: Not Reported
Current survey date: Not Reported

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Medicare/Medicaid:	Not Reported	
	Facility name:	SALLY MORGAN NURSE PRACTITIONER	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20030611	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D1013578	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	158 N BROADWAY	
	Phone num:	7609218484	
	Termination reason:	08	
	Term Date:	20050610	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070160710	

D21			SRHO20070149183
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
27984	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	DESERT HOME HEALTH CARE	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19970910	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0933305	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	

	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	158 NORTH BROADWAY	
	Phone num:	7609210042	
	Termination reason:	08	
	Term Date:	19970910	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070149183	

D22			SRPR20051024377
East	Pss school id:	A0300249	Private Schools
4-6 mi	Pss inst:	ESCUELA DE LA RAZA UNIDA	
27990	Lograde:	K	
Lower	Higrade:	12	
	Pss address:	137 N BROADWAY	
	Pss city:	BLYTHE	
	Pss county no:	065	
	Pss county fips:	06065	
	Pss stabb:	CA	
	Pss fips:	06	
	Pss zip5:	92225	
	Pss phone:	7609222582	
	Pss sch days:	175	
	Pss stu day hrs:	6.5	
	Pss library:	Yes	
	Pss enroll ug:	2	
	Pss enroll pk:	Not Reported	
	Pss enroll k:	1	
	Pss enroll 1:	1	
	Pss enroll 2:	1	
	Pss enroll 3:	1	
	Pss enroll 4:	1	
	Pss enroll 5:	1	
	Pss enroll 6:	Not Reported	
	Pss enroll 7:	1	
	Pss enroll 8:	6	
	Pss enroll 9:	3	
	Pss enroll 10:	Not Reported	
	Pss enroll 11:	1	
	Pss enroll 12:	1	
	Pss enroll t:	20	
	Pss enroll tk12:	20	

Pss race ai:	0
Pss race as:	0
Pss race h:	17
Pss race b:	2
Pss race w:	Not Reported
Pss fte teach:	2.3
Pss locale:	3
Pss coed:	1
Pss type:	1
Pss level:	3
Pss relig:	3
Pss comm type:	2
Pss indian pct:	0
Pss asian pct:	0
Pss hisp pct:	85
Pss black pct:	10
Pss white pct:	Not Reported
Pss stdtch rt:	8.7
Pss orient:	29
Pss county name:	RIVERSIDE
Pss assoc 1:	No Membership Association
Pss assoc 2:	Not Reported
Pss assoc 3:	Not Reported
Pss assoc 4:	Not Reported
Pss assoc 5:	Not Reported
Pss assoc 6:	Not Reported
Pss assoc 7:	Not Reported
Source:	NCESDATA_E72D09B4
Edr id:	SRPR20051024377

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23 SRDCCA200711601
East Daycare
4-6 mi
28250
Lower

EDR ID:	SRDCCA200711601
Facility number:	334802724
Facility name:	MC CARTHY FAMILY DAY CARE
Facility eval. code:	0555
Facility office number:	09
Facility county number:	33
Facility type code:	810
Facility status code:	03
Address:	205 EUNICE CIRCLE
City:	BLYTHE
State:	CA
Zip:	92225
Alt. address:	205 EUNICE CIRCLE
City:	BLYTHE
State:	CA
Zip:	92225
Facility investor:	"MC CARTHY, MALINDA "
Licensee type:	A
License effective date:	960606
License expiration date:	Not Reported
License issue date:	960606
Program type:	"MAXIMUM CAPACITY: 12 CHILDREN, WITH NO MORE THAN 4 INFANTS, OR CAPACITY 14 CHILDREN WHEN 2 CHILDREN ARE AT LEAST 6 YEARS OF AGE WITH A MAXIMUM OF 3 INFANTS; PROPERTY OWNER/LANDLORD CONSENT IS REQUIRED "OFF LIMITS: UPSTAIRS AREA AND GARAGE

Map ID Direction Distance Distance (ft.) Elevation	Site	EDR ID Database

	Original app. received date:	960423
	Facility closed date:	Not Reported
	Mailing address:	205 EUNICE CIRCLE
	Mailing city:	BLYTHE
	Mailing state:	CA
	Mailing zip:	92225
	Contact person:	"MC CARTHY, MALINDA "
	Facility capacity:	14
	Type of clients served:	960
	Facility phone:	7609229261

F24 SRDCCA200739504
East 4-6 mi 28252 Lower — Daycare

EDR ID:	SRDCCA200739504
Facility number:	334818754
Facility name:	RIVERA FAMILY CHILD CARE
Facility eval. code:	0555
Facility office number:	09
Facility county number:	33
Facility type code:	810
Facility status code:	03
Address:	419 N. 1ST STREET
City:	BLYTHE
State:	CA
Zip:	92225
Alt. address:	419 N. 1ST STREET
City:	BLYTHE
State:	CA
Zip:	92225
Facility investor:	"RIVERA, LETICIA "
Licensee type:	A
License effective date:	70329
License expiration date:	Not Reported
License issue date:	070329
Program type:	MAX. CAP(WHEN THERE IS AN ASSISTANT PRESENT): 12 - NO MORE THAN 4 INFANTS. CAP 14 - NO MORE THAN 3 INFANTS. 1 CHILD IN KINDERGARTEN OR ELEMENTARY SCHOOL AND 1 CHILD AT LEAST AGE 6.
Original app. received date:	070307
Facility closed date:	Not Reported
Mailing address:	419 N. 1ST STREET
Mailing city:	BLYTHE
Mailing state:	CA
Mailing zip:	92225
Contact person:	"RIVERA, LETICIA "
Facility capacity:	14
Type of clients served:	960
Facility phone:	7609213904

F25 SRDCCA200727230
East 4-6 mi 28293 Lower — Daycare

EDR ID:	SRDCCA200727230
Facility number:	334815071
Facility name:	ROPPOLO FAMILY CHILD CARE
Facility eval. code:	0555
Facility office number:	09
Facility county number:	33

Facility type code:	810
Facility status code:	03
Address:	325 NORTH FIRST STREET
City:	BLYTHE
State:	CA
Zip:	92225
Alt. address:	325 NORTH FIRST STREET
City:	BLYTHE
State:	CA
Zip:	92225
Facility investor:	"ROPPOLO, SHELLY "
Licensee type:	A
License effective date:	40722
License expiration date:	Not Reported
License issue date:	040722
Program type:	"MAXIMUM CAPACITY: 6 CHILDREN WITH NO MORE THAN 3 INFANTS, OR 4 INFANTSONLY, OR CAPACITY 8 CHILDREN WHEN 2 ARE AT LEAST 6 YEARS OF AGE WITH AMAXIMUM OF 2 INFANTS.OFF LIMITS:BASEMENT AND ALL BEDROOMS. "
Original app. received date:	040504
Facility closed date:	Not Reported
Mailing address:	325 NORTH FIRST STREET
Mailing city:	BLYTHE
Mailing state:	CA
Mailing zip:	92225
Contact person:	"ROPPOLO, SHELLY "
Facility capacity:	8
Type of clients served:	960
Facility phone:	7609212437

F26
East
4-6 mi
28343
Lower

SRHO20070139735
AHA Hospitals

Hospital type:	01
Num of times COO:	00
Owner date:	Not Reported
City:	BLYTHE
Has plan of corr:	1
Compliance status:	A
SSA county code:	430
Cross ref number:	Not Reported
FMS survey date:	Not Reported
Current survey date:	19971218
Medicare/Medicaid:	1
Facility name:	PALO VERDE HOSP ARTERIAL BLOOD GAS LAB
Intermediary/Carrier:	00542
Medicaid number:	Not Reported
Partcipation date:	19920901
Prior COO date:	Not Reported
Prior carrier:	Not Reported
Provider ID:	05D0713330
Record Status:	A
Region code:	09
Is Partial Record:	Not Reported
state abbrev:	CA
ssa state:	05
state region cd:	M1

	street address:	250 N FIRST STREET	
	Phone num:	6199224115	
	Termination reason:	00	
	Term Date:	20070307	
	Purpose of action:	2	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070139735	

F27			SRHO20070006967
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	02	
28343	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	1	
	Compliance status:	A	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	19980203	
	Medicare/Medicaid:	1	
	Facility name:	PALO VERDE HOSPITAL	
	Intermediary/Carrier:	00040	
	Medicaid number:	Not Reported	
	Partcipation date:	19660701	
	Prior COO date:	19930101	
	Prior carrier:	Not Reported	
	Provider ID:	050423	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	RIV	
	street address:	250 NORTH FIRST STREET	
	Phone num:	7609224115	
	Termination reason:	00	
	Term Date:	Not Reported	
	Purpose of action:	2	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	

Date accredited:	19981015	
Accred expire date:	20011014	
Accred Org:	1	
Num beds:	0055	
Num cert beds:	0055	
Source:	US_HOSPITAL_POSOTHER	
Edr id:	SRHO20070006967	

F28			SRHO20070132024
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28343	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	1	
	Compliance status:	A	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	19971218	
	Medicare/Medicaid:	1	
	Facility name:	PALO VERDE HOSPITAL LABORATORY	
	Intermediary/Carrier:	00542	
	Medicaid number:	Not Reported	
	Partcipation date:	19920901	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0571998	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	M1	
	street address:	250 N FIRST STREET	
	Phone num:	6199224115	
	Termination reason:	00	
	Term Date:	20070307	
	Purpose of action:	2	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070132024	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
G29			SRHO20070149828
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28362	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	PATRICK N BAYS DO	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19980917	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0951433	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	205 N FIRST STREET SUITE A	
	Phone num:	7609226355	
	Termination reason:	08	
	Term Date:	19980918	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070149828	
G30			SRHO20070151101
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28362	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Medicare/Medicaid:	Not Reported	
	Facility name:	LEONEL L RODRIGUEZ MD	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19980723	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0949010	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	205 N FIRST STREET SUITE C	
	Phone num:	7609224115	
	Termination reason:	00	
	Term Date:	20080722	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070151101	

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
G31			SRHO20070161110
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28362	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	ANJANI THAKUR MD INC	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20050923	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D1045800	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	M1	
	street address:	205 N FIRST ST	
	Phone num:	7609221022	
	Termination reason:	00	
	Term Date:	20070922	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070161110	

G32			SRHO20070151664
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28362	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	HOSSAIN SAHLOLBEI MD	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19980619	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0947616	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	205 N FIRST STREET, SUITE B	
	Phone num:	7609212342	
	Termination reason:	01	
	Term Date:	19981006	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070151664	

F33			SRDCCA200731832
East	EDR ID:	SRDCCA200731832	Daycare
4-6 mi	Facility number:	334816673	
28660	Facility name:	ZAMORA FAMILY CHILD CARE	
Lower	Facility eval. code:	0555	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	810	
	Facility status code:	03	
	Address:	401 N. 2ND ST.	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	401 N. 2ND ST.	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Facility investor:	"ZAMORA, THERESA "	
	Licensee type:	A	
	License effective date:	60202	
	License expiration date:	Not Reported	
	License issue date:	060202	
	Program type:	"MAX. CAP: 6 - NO MORE THAN 3 INFANTS OR 4 INFANTS ONLY. CAP 8 - NO MORE THAN 2 INFANTS, 1 CHILD IN KINDERGARTEN OR ELEMENTARY SCHOOL AND 1 CHILD AT LEAST AGE 6. ""OFF LIMIT AREAS: ALL BEDROOMS, LAUNDRY ROOM, GARAGE & FRONT YARD "	
	Original app. received date:	050715	
	Facility closed date:	Not Reported	
	Mailing address:	401 N. 2ND ST.	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	"ZAMORA, THERESA "	
	Facility capacity:	8	
	Type of clients served:	960	
	Facility phone:	7609225196	

G34			SRHO20070132023
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28685	Owner date:	Not Reported	
Lower	City:	BLYTHE	

	Has plan of corr:	1
	Compliance status:	A
	SSA county code:	430
	Cross ref number:	Not Reported
	FMS survey date:	Not Reported
	Current survey date:	19980205
	Medicare/Medicaid:	1
	Facility name:	ROGER C SLATER MD INC
	Intermediary/Carrier:	00542
	Medicaid number:	Not Reported
	Partcipation date:	19920901
	Prior COO date:	Not Reported
	Prior carrier:	Not Reported
	Provider ID:	05D0571989
	Record Status:	A
	Region code:	09
	Is Partial Record:	Not Reported
	state abbrev:	CA
	ssa state:	05
	state region cd:	M1
	street address:	240 EAST HOBSONWAY
	Phone num:	6199222155
	Termination reason:	12
	Term Date:	20000105
	Purpose of action:	2
	Provider control:	04
	Zip:	92225
	Fips state:	06
	Fips cnty:	065
	SSA MSA:	488
	SSA MSA size code:	B
	Date accredited:	Not Reported
	Accred expire date:	Not Reported
	Accred Org:	Not Reported
	Num beds:	0000
	Num cert beds:	0000
	Source:	US_HOSPITAL_POSCLIA
	Edr id:	SRHO20070132023

G35			SRHO20070153768
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
28685	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	RAZAN AMMARI MD	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	20001222	

Prior COO date:	Not Reported
Prior carrier:	Not Reported
Provider ID:	05D0981315
Record Status:	A
Region code:	09
Is Partial Record:	Y
state abbrev:	CA
ssa state:	05
state region cd:	LAB
street address:	240 E HOBSONWAY
Phone num:	7609222155
Termination reason:	08
Term Date:	20041221
Purpose of action:	Not Reported
Provider control:	04
Zip:	92225
Fips state:	06
Fips cnty:	065
SSA MSA:	488
SSA MSA size code:	B
Date accredited:	Not Reported
Accred expire date:	Not Reported
Accred Org:	Not Reported
Num beds:	0000
Num cert beds:	0000
Source:	US_HOSPITAL_POSCLIA
Edr id:	SRHO20070153768

F36 — SRDCCA200744229
East — Daycare
4-6 mi
28890
Lower

EDR ID:	SRDCCA200744229
Facility number:	330908924
Facility name:	COMMUNITY UNITED METHODIST CHURCH PRESCHOOL
Facility eval. code:	0775
Facility office number:	09
Facility county number:	33
Facility type code:	840
Facility status code:	03
Address:	345 E. BARNARD
City:	BLYTHE
State:	CA
Zip:	92225
Alt. address:	345 E. BARNARD STREET
City:	BLYTHE
State:	CA
Zip:	92225
Facility investor:	COMMUNITY UNITED METHODIST CHURCH
Licensee type:	C
License effective date:	930803
License expiration date:	Not Reported
License issue date:	880919
Program type:	29 CHILDREN AGES 6 THROUGH 12 YEARS IN ROOMS #1 & #2. REST ROOMS IN CHURCH. HOURS: MONDAY THROUGH FRIDAY 6:30AM TO 5:30PM.
Original app. received date:	880912
Facility closed date:	Not Reported
Mailing address:	345 E. BARNARD STREET

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	BRENDA ANDERSON	
	Facility capacity:	29	
	Type of clients served:	950	
	Facility phone:	7609223210	

G37			SRDCCA200710875
East	EDR ID:	SRDCCA200710875	Daycare
4-6 mi	Facility number:	334807029	
29278	Facility name:	COSTILLA FAMILY CHILD CARE	
Lower	Facility eval. code:	0555	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	810	
	Facility status code:	03	
	Address:	425 E. MURPHY ST.	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	425 E. MURPHY ST.	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Facility investor:	"COSTILLA, CINDY "	
	Licensee type:	A	
	License effective date:	515	
	License expiration date:	Not Reported	
	License issue date:	000515	
	Program type:	INACTIVE LICENSE: INACTIVE FROM 11-30-2006 THROUGH INDEFINITELY.	
	Original app. received date:	991224	
	Facility closed date:	Not Reported	
	Mailing address:	425 E. MURPHY ST.	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	"COSTILLO, CINDY "	
	Facility capacity:	14	
	Type of clients served:	960	
	Facility phone:	7609220900	

38			SRDCCA200704135
East	EDR ID:	SRDCCA200704135	Daycare
4-6 mi	Facility number:	330919967	
29865	Facility name:	MACK FAMILY DAY CARE	
Lower	Facility eval. code:	0555	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	810	
	Facility status code:	03	
	Address:	400 SO. FOURTH	
	City:	BLYTHE	
	State:	CA	

Zip:	92225	
Alt. address:	400 SO. FOURTH	
City:	BLYTHE	
State:	CA	
Zip:	92225	
Facility investor:	"MACK, SERITHA "	
Licensee type:	A	
License effective date:	911214	
License expiration date:	Not Reported	
License issue date:	911214	
Program type:	"MAXIMUM CAPACITY;12CHILDREN,WITH NO MORE THAN 4 INFANTS,OR A MAXIMUM 14 CHILDREN WHEN 2 ARE AT LEAST 6 YEARS OF AGE WITH A MAXIMUM OF 3 INFANTS; OFF LIMIS: ALL BEDROOMS. "	
Original app. received date:	881214	
Facility closed date:	Not Reported	
Mailing address:	400 SO. FOURTH	
Mailing city:	BLYTHE	
Mailing state:	CA	
Mailing zip:	92225	
Contact person:	"MACK, S. "	
Facility capacity:	14	
Type of clients served:	960	
Facility phone:	7609223614	

Map ID	Field	Value	EDR ID / Database
H39			SRPU20071010977
East	Ncessch:	062964004603	Public Schools
4-6 mi	Schname05:	TWIN PALMS CONTINUATION	
29945	Mstreet05:	190 NORTH FIFTH ST.	
Lower	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	1726	
	Member05:	80	
	Phone05:	(760) 922-4884	
	Locale05:	3	
	Type05:	4	
	Level05:	3	
	Gslo05:	10	
	Gshi05:	12	
	Edr id:	SRPU20071010977	

Map ID	Field	Value	EDR ID / Database
H40			SRHO20070147205
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
30026	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Facility name:	DATE PALM, INC	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19930604	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0871765	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	LAB	
	street address:	604 E HOBSON WAY	
	Phone num:	6199223644	
	Termination reason:	00	
	Term Date:	20071104	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070147205	

H41			SRHO20070147854
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
30447	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	Not Reported	
	SSA county code:	430	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	Not Reported	
	Medicare/Medicaid:	Not Reported	
	Facility name:	BLYTHE DESERT DIALYSIS	
	Intermediary/Carrier:	Not Reported	
	Medicaid number:	Not Reported	
	Partcipation date:	19970227	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	05D0925504	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Y	
	state abbrev:	CA	

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	ssa state:	05	
	state region cd:	LAB	
	street address:	737 HOBSON WAY	
	Phone num:	6199224415	
	Termination reason:	00	
	Term Date:	20070226	
	Purpose of action:	Not Reported	
	Provider control:	04	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	065	
	SSA MSA:	488	
	SSA MSA size code:	B	
	Date accredited:	Not Reported	
	Accred expire date:	Not Reported	
	Accred Org:	Not Reported	
	Num beds:	0000	
	Num cert beds:	0000	
	Source:	US_HOSPITAL_POSCLIA	
	Edr id:	SRHO20070147854	

H42			SRHO20070008900
East	Hospital type:	01	AHA Hospitals
4-6 mi	Num of times COO:	00	
30447	Owner date:	Not Reported	
Lower	City:	BLYTHE	
	Has plan of corr:	Not Reported	
	Compliance status:	A	
	SSA county code:	460	
	Cross ref number:	Not Reported	
	FMS survey date:	Not Reported	
	Current survey date:	19971009	
	Medicare/Medicaid:	1	
	Facility name:	BMA BLYTHE DESERT DIALYSIS	
	Intermediary/Carrier:	00040	
	Medicaid number:	Not Reported	
	Partcipation date:	19971009	
	Prior COO date:	Not Reported	
	Prior carrier:	Not Reported	
	Provider ID:	052812	
	Record Status:	A	
	Region code:	09	
	Is Partial Record:	Not Reported	
	state abbrev:	CA	
	ssa state:	05	
	state region cd:	BER	
	street address:	737 WEST HOBSON WAY	
	Phone num:	7609224415	
	Termination reason:	00	
	Term Date:	Not Reported	
	Purpose of action:	1	
	Provider control:	01	
	Zip:	92225	
	Fips state:	06	
	Fips cnty:	071	

Map ID
Direction
Distance
Distance (ft.)
Elevation **Site** **EDR ID** **Database**

SSA MSA:	488
SSA MSA size code:	B
Date accredited:	Not Reported
Accred expire date:	Not Reported
Accred Org:	Not Reported
Num beds:	0000
Num cert beds:	0000
Source:	US_HOSPITAL_POSOTHER
Edr id:	SRHO20070008900

I43 SRDCCA200754912
East Daycare
4-6 mi
30491
Lower

EDR ID:	SRDCCA200754912
Facility number:	334818402
Facility name:	ESCUELA DE LA RAZA-PRIMEROS PASOS CENTER
Facility eval. code:	0775
Facility office number:	09
Facility county number:	33
Facility type code:	850
Facility status code:	03
Address:	405 N. 7TH
City:	BLYTHE
State:	CA
Zip:	92225
Alt. address:	P.O. BOX 910
City:	BLYTHE
State:	CA
Zip:	92226
Facility investor:	ESCUELA DE LA RAZA UNIDA
Licensee type:	C
License effective date:	70530
License expiration date:	Not Reported
License issue date:	070530
Program type:	HOURS OF OPERATION: MONDAY-FRIDAY; FROM 6:30 AM TO 5:30 PM FOR AGES 2 YEARS TO FIRST DAY OF KINDERGARTEN.
Original app. received date:	061117
Facility closed date:	Not Reported
Mailing address:	P.O. BOX 910
Mailing city:	BLYTHE
Mailing state:	CA
Mailing zip:	92226
Contact person:	"GARNICA, CARMELA "
Facility capacity:	21
Type of clients served:	950
Facility phone:	7609229080

I44 SRDCCA200743818
East Daycare
4-6 mi
30491
Lower

EDR ID:	SRDCCA200743818
Facility number:	334818403
Facility name:	ESCUELA DE LA RAZA UNIDA-PRIMEROS PASOS CENTER
Facility eval. code:	0775
Facility office number:	09
Facility county number:	33
Facility type code:	830
Facility status code:	03

MAP FINDINGS

Map ID Direction Distance Distance (ft.) Elevation	Site		EDR ID Database
	Address:	405 NORTH 7TH	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Alt. address:	P.O. BOX 910	
	City:	BLYTHE	
	State:	CA	
	Zip:	92225	
	Facility investor:	ESCUELA DE LA RAZA UNIDA	
	Licensee type:	C	
	License effective date:	70530	
	License expiration date:	Not Reported	
	License issue date:	070530	
	Program type:	HOURS OF OPERATION: MONDAY-FRIDAY FROM 6:30 AM TO 5:30 PM FOR AGES GIRTH TO 2 YEARS.	
	Original app. received date:	061117	
	Facility closed date:	Not Reported	
	Mailing address:	P.O. BOX 910	
	Mailing city:	BLYTHE	
	Mailing state:	CA	
	Mailing zip:	92225	
	Contact person:	"GARNICA, CARMELA "	
	Facility capacity:	16	
	Type of clients served:	955	
	Facility phone:	7609229080	

H45			SRPU20071010975
East	Ncessch:	062964004601	Public Schools
4-6 mi	Schname05:	RUTH BROWN ELEMENTARY	
30569	Mstreet05:	241 NORTH SEVENTH AVE.	
Lower	Mcity05:	BLYTHE	
	Mstate05:	CA	
	Mzip05:	92225	
	Mzip405:	1825	
	Member05:	649	
	Phone05:	(760) 922-7164	
	Locale05:	3	
	Type05:	1	
	Level05:	1	
	Gslo05:	KG	
	Gshi05:	05	
	Edr id:	SRPU20071010975	

H46			SRDCCA200724500
East	EDR ID:	SRDCCA200724500	Daycare
4-6 mi	Facility number:	334814865	
30917	Facility name:	THOMAS FAMILY CHILD CARE	
Lower	Facility eval. code:	0555	
	Facility office number:	09	
	Facility county number:	33	
	Facility type code:	810	
	Facility status code:	03	
	Address:	901 EAST AVENUE A	
	City:	BLYTHE	

State:	CA
Zip:	92225
Alt. address:	901 EAST AVENUE A
City:	BLYTHE
State:	CA
Zip:	92225
Facility investor:	"THOMAS, LINDA "
Licensee type:	A
License effective date:	40407
License expiration date:	Not Reported
License issue date:	040407
Program type:	"MAXIMUM CAPACITY: 6 CHILDREN WITH NO MORE THAN 3 INFANTS, OR 4 INFANTSONLY, OR CAPACITY 8 CHILDREN WHEN 2 ARE AT LEAST 6 YEARS OF AGE WITH AMAXIMUM OF 2 INFANTS; PROPERTY OWNER/LANDLORD CONSENT IS REQUIRED "
Original app. received date:	040406
Facility closed date:	Not Reported
Mailing address:	901 EAST AVENUE A
Mailing city:	BLYTHE
Mailing state:	CA
Mailing zip:	92225
Contact person:	"THOMAS, LINDA "
Facility capacity:	8
Type of clients served:	960
Facility phone:	7609218685

NA			CUSA143499
NE	Name:	Big Maria Mountains Wilderness	FED_LAND
8-10 mi	Feature:	Wilderness BLM	
47638	Feature:	Public Domain Land BLM	
NA	URL:	http://www.wilderness.net/index.cfm?fuse=NWPS&sec=wildView&wname=Big%20Maria%20Mou	
	Bureau:	BLM	
	State:	CA	
	Is DOD?:	No	

NA			CUSA144151
SE	Name:	Not Reported	FED_LAND
8-10 mi	Feature:	Public Domain Land BLM	
52687	URL:	Not Reported	
NA	Bureau:	BLM	
	State:	AZ-CA	
	Is DOD?:	No	

RECORDS SEARCHED/DATA CURRENCY TRACKING

Census
Source: U.S. Census Bureau
Telephone: 301-763-4636
2010 U.S. Census data was used to estimate residential population following these EPA guidelines:
"Census data are presented by Census tract. If your circle covers only a portion of the tract, you should develop an estimate for that portion...Determine the population density per square mile (total population of the Census tract divided by the number of square miles in the tract) and apply that density figure to the number of square miles within your circle."

FED_LAND: Federal Lands
Source: USGS
Telephone: 888-275-8747
Federal lands data. Includes data from several Federal land management agencies, including Fish and Wildlife Service, Bureau of Land Management, National Park Service, and Forest Service. Includes National Parks, Forests, Monuments; . Wildlife Sanctuaries, Preserves, Refuges; Federal Wilderness Areas.

AHA Hospitals:
Source: American Hospital Association, Inc.
Telephone: 312-280-5991
The database includes a listing of hospitals based on the American Hospital Association's annual survey of hospitals.

Medical Centers: Provider of Services Listing
Source: Centers for Medicare & Medicaid Services
Telephone: 410-786-3000
A listing of hospitals with Medicare provider number, produced by Centers of Medicare & Medicaid Services, a federal agency within the U.S. Department of Health and Human Services.

Nursing Homes
Source: National Institutes of Health
Telephone: 301-594-6248
Information on Medicare and Medicaid certified nursing homes in the United States.

Public Schools
Source: National Center for Education Statistics
Telephone: 202-502-7300
The National Center for Education Statistics' primary database on elementary and secondary public education in the United States. It is a comprehensive, annual, national statistical database of all public elementary and secondary schools and school districts, which contains data that are comparable across all states.

Private Schools
Source: National Center for Education Statistics
Telephone: 202-502-7300
The National Center for Education Statistics' primary database on private school locations in the United States.

Colleges - Integrated Postsecondary Education Data
Source: National Center for Education Statistics
Telephone: 202-502-7300
The National Center for Education Statistics' primary database on integrated postsecondary education in the United States.

Arenas
Source: Dunhill International
EDR indicates the location of buildings and facilities - arenas - where individuals who are public receptors are likely to be located.

Prisons: Bureau of Prisons Facilities
Source: Federal Bureau of Prisons
Telephone: 202-307-3198
List of facilities operated by the Federal Bureau of Prisons.

Daycare Centers: Licensed Facilities
Source: Department of Social Services
Telephone: 916-657-4041

STREET AND ADDRESS INFORMATION

HARP Receptor Number	EDR ID	Receptor Category	Receptor Name	Distance from Project (ft)	Elevation, ft	Receptor Location, lat/long		Receptor Location, UTM	
						W	N	UTM-E (m)	UTM-N (m)
** HARP Receptor No. 15217	SRCL20051000408	College	PALO VERDE COLLEGE	18,817	369	-114.65184	33.66073	717729.46	3727013.2
** HARP Receptor No. 15218	SSRDCCA200741231	Daycare	ESCUELA DE LA RAZA UNIDA, INC., CHILD DEV. CTR.	23,893	268	-114.61004	33.61423	721725.4	3721944.9
** HARP Receptor No. 15219	SSRDCCA200753503	Daycare	ESCUELA DE LA RAZA UNIDA, INC. CHILD DEV. CTR.	23,893	268	-114.61004	33.61423	721725.4	3721944.9
** HARP Receptor No. 15220	SSRDCCA200704054	Daycare	COPELAND FAMILY DAY CARE	25,520	271	-114.60452	33.61709	722230.28	3722273.9
** HARP Receptor No. 15221	SSRDCCO200704898	Daycare	FLORES TERESA	26,143	273	-114.60247	33.6206	722411.48	3722667.6
** HARP Receptor No. 15222	SSRDCCA200711601	Daycare	MC CARTHY FAMILY DAY CARE	28,250	273	-114.59563	33.62275	723040.61	3722920.8
** HARP Receptor No. 15223	SSRDCCA200739504	Daycare	RIVERA FAMILY CHILD CARE	28,252	272	-114.59558	33.61624	723062.03	3722198.9
** HARP Receptor No. 15224	SSRDCCA200727230	Daycare	ROPPOLO FAMILY CHILD CARE	28,294	272	-114.59554	33.61452	723070.18	3722008.2
** HARP Receptor No. 15225	SSRDCCA200731832	Daycare	ZAMORA FAMILY CHILD CARE	28,660	270	-114.59425	33.61596	723186.17	3722170.7
** HARP Receptor No. 15226	SSRDCCA200744229	Daycare	COMMUNITY UNITED METHODIST CHURCH PRESCHOOL	28,890	272	-114.5936	33.61409	723251.31	3721964.7
** HARP Receptor No. 15227	SSRDCCA200710875	Daycare	COSTILLA FAMILY CHILD CARE	29,278	272	-114.59248	33.6123	723359.86	3721768.6
** HARP Receptor No. 15228	SSRDCCA200704135	Daycare	MACK FAMILY DAY CARE	29,866	269	-114.59167	33.60492	723454.08	3720951.8
** HARP Receptor No. 15229	SSRDCCA200754912	Daycare	ESCUELA DE LA RAZA-PRIMEROS PASOS CENTER	30,491	263	-114.58825	33.61556	723743.96	3722139.3
** HARP Receptor No. 15230	SSRDCCA200743818	Daycare	ESCUELA DE LA RAZA UNIDA-PRIMEROS PASOS CENTER	30,491	263	-114.58825	33.61556	723743.96	3722139.3
** HARP Receptor No. 15231	SSRDCCA200724500	Daycare	THOMAS FAMILY CHILD CARE	30,918	272	-114.58715	33.61156	723856.38	3721698
** HARP Receptor No. 15232	SSRHO20070150021	Hospital	KENNETH G LUCERO MD	23,729	267	-114.6111	33.61014	721637.51	3721489
** HARP Receptor No. 15233	SSRHO20070159409	Hospital	DARIN D LU MD	27,023	269	-114.60016	33.61029	722652.35	3721529.1
** HARP Receptor No. 15234	SSRHO20070150105	Hospital	BLYTHE FAMILY HEALTH CLINIC	27,039	269	-114.60011	33.61032	722656.91	3721532.5
** HARP Receptor No. 15235	SSRHO20070004245	Hospital	BLYTHE NURSING CARE CENTER	27,063	272	-114.59944	33.6176	722700.35	3722341.4
** HARP Receptor No. 15236	SSRHO20070005246	Hospital	BLYTHE NURSING CARE CENTER	27,063	272	-114.59944	33.6176	722700.35	3722341.4
** HARP Receptor No. 15237	SSRHO20070144362	Hospital	BLYTHE NURSING CARE CENTER	27,063	272	-114.59944	33.6176	722700.35	3722341.4
** HARP Receptor No. 15238	SSRHO20070160940	Hospital	FRANCISCO J TEJEDA MD MEDICAL CLINIC	27,761	270	-114.59772	33.61033	722878.68	3721538.8
** HARP Receptor No. 15239	SSRHO20070158992	Hospital	KEITH MARK GROSS MD INC	27,817	272	-114.59696	33.61768	722930.27	3722355.6
** HARP Receptor No. 15240	SSRHO20070141583	Hospital	LEON PETER Y CHUA MD	27,817	272	-114.59696	33.61768	722930.27	3722355.6
** HARP Receptor No. 15241	SSRHO20070145971	Hospital	CARDIOPUL SERVS ART BLD GAS LABORATORY	27,817	272	-114.59696	33.61768	722930.27	3722355.6
** HARP Receptor No. 15242	SSRHO20070160710	Hospital	SALLY MORGAN NURSE PRACTITIONER	27,985	271	-114.59683	33.61153	722958.18	3721673.8
** HARP Receptor No. 15243	SSRHO20070149183	Hospital	DESERT HOME HEALTH CARE	27,985	271	-114.59683	33.61153	722958.18	3721673.8
** HARP Receptor No. 15244	SSRHO20070139735	Hospital	PALO VERDE HOSP ARTERIAL BLOOD GAS LAB	28,343	272	-114.59548	33.61316	723079.25	3721857.5
** HARP Receptor No. 15245	SSRHO20070006967	Hospital	PALO VERDE HOSPITAL	28,343	272	-114.59548	33.61316	723079.25	3721857.5
** HARP Receptor No. 15246	SSRHO20070132024	Hospital	PALO VERDE HOSPITAL LABORATORY	28,343	272	-114.59548	33.61316	723079.25	3721857.5
** HARP Receptor No. 15247	SSRHO20070149828	Hospital	PATRICK N BAYS DO	28,362	272	-114.59549	33.61236	723080.39	3721768.7
** HARP Receptor No. 15248	SSRHO20070151101	Hospital	LEONEL L RODRIGUEZ MD	28,362	272	-114.59549	33.61236	723080.39	3721768.7

HARP Receptor Number	EDR ID	Receptor Category	Receptor Name	Distance from Project (ft)	Elevation, ft	Receptor Location, lat/long		Receptor Location, UTM	
						W	N	UTM-E (m)	UTM-N (m)
** HARP Receptor No. 15249	SSRHO20070161110	Hospital	ANJANI THAKUR MD INC	28,362	272	-114.59549	33.61236	723080.39	3721768.7
** HARP Receptor No. 15250	SSRHO20070151664	Hospital	HOSSAIN SAHLOLBEI MD	28,362	272	-114.59549	33.61236	723080.39	3721768.7
** HARP Receptor No. 15251	SSRHO20070132023	Hospital	ROGER C SLATER MD INC	28,686	271	-114.59466	33.61038	723162.51	3721550.9
** HARP Receptor No. 15252	SSRHO20070153768	Hospital	RAZAN AMMARI MD	28,686	271	-114.59466	33.61038	723162.51	3721550.9
** HARP Receptor No. 15253	SSRHO20070147205	Hospital	DATE PALM, INC	30,026	272	-114.59022	33.61045	723574.36	3721568.3
** HARP Receptor No. 15254	SSRHO20070147854	Hospital	BLYTHE DESERT DIALYSIS	30,448	272	-114.58882	33.6105	723704.15	3721576.9
** HARP Receptor No. 15255	SSRHO20070008900	Hospital	BMA BLYTHE DESERT DIALYSIS	30,448	272	-114.58882	33.6105	723704.15	3721576.9
** HARP Receptor No. 15256	SSRPU20071010973	School	FELIX J. APPLEBY ELEMENTARY	25,112	271	-114.60585	33.61747	722105.89	3722313.2
** HARP Receptor No. 15257	SSRPU20071010976	School	PALO VERDE HIGH	25,140	272	-114.60577	33.62108	722104.05	3722713.7
** HARP Receptor No. 15258	SSRPU20071010974	School	BLYTHE MIDDLE	25,170	272	-114.60583	33.62367	722091.83	3723000.9
** HARP Receptor No. 15259	SSRPU20071010978	School	MARGARET WHITE ELEMENTARY	27,799	272	-114.59701	33.62008	722919.44	3722621.7
** HARP Receptor No. 15260	SSRPR20051024377	School	ESCUELA DE LA RAZA UNIDA	27,990	270	-114.59685	33.6112	722957.17	3721637.2
** HARP Receptor No. 15261	SSRPU20071010977	School	TWIN PALMS CONTINUATION	29,945	272	-114.59032	33.61197	723561.16	3721736.7
** HARP Receptor No. 15262	SSRPU20071010975	School	RUTH BROWN ELEMENTARY	30,569	269	-114.58816	33.61304	723758.83	3721860
** HARP Receptor No. 15263	n/a	Wilderness	Big Maria Mountains Wilderness	85,716	2198			717519.27	3747623.4
** HARP Receptor No. 15264	n/a	Residence	Nearest Residence	4,055	366			713343.53	3721091.4
** HARP Receptor No. 15265	n/a	Prison	Ironwood State Prison	74,954	453			692462	3715409
** HARP Receptor No. 15266	n/a	Prison	Chuckwalla Valley State Prison	69,750	446			694051	3715625

Appendix B

Permit Application Forms, SEP

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print — REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.	1a. Federal Tax ID No.:
2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060	
3. Facility or Business License Name (for equipment location): Sonoran Energy Project	
4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe	Location UTM or Lat/Long: 714430.248E 3721680.367N

5. Contact Name/Title:	Email Address:	Phone/Fax Nos.:
Christopher J. Doyle	Chris.Doyle@altagas.ca	(604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment:
GE 7HA.02 gas turbine with duct firing

Air Pollution Control Equipment, if any (note that most APCE require a separate application):
SCR and oxidation catalyst

7. Application is for:
☒ New Construction ☐ Modification* ☐ Change of Owner*

For modification or change of owner:
*Current Permit Number: ______

8. Type of Organization (check one):
☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business:	Principal Product:	SIC Code (if known):
Electric power generation	electricity	4911

10. Distances (feet and direction to closest):

Fenceline	Residence	Business	School
954 W	4,055 SW	7,336 WSW	20,926 E

11. Facility Annual Throughput by Quarters (percent):

Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
25 %	25 %	25 %	25 %

12. Expected Facility Operating Hours:

Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr
7	24	52	up to 8,760

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official:	Official Title: Vice President	
Typed or Printed Name of Responsible Official: Christopher J. Doyle	Phone Number: (604) 623-4797	Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

 please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	140 ft	22 ft	155 F	1,637,212 acfm	71.8 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print
REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.	1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060

3. Facility or Business License Name (for equipment location): Sonoran Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe	Location UTM or Lat/Long: 714430.248E 3721680.367N

5. Contact Name/Title: Christopher J. Doyle	Email Address: Chris.Doyle@altagas.ca	Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment:
HRSG duct burner, maximum heat input of 222.6 MMBtu/hr (HHV)

Air Pollution Control Equipment, if any (note that most APCE require a separate application):
SCR and oxidation catalyst

7. Application is for: [x] New Construction [ ] Modification* [ ] Change of Owner*	For modification or change of owner: *Current Permit Number:

8. Type of Organization (check one):
[ ] Individual Owner [ ] Partnership [x] Corporation [ ] Utility [ ] Local Agency [ ] State Agency [ ] Federal Agency

9. General Nature of Business: Electric power generation	Principal Product: electricity	SIC Code (if known): 4911

10. Distances (feet and direction to closest):

Fenceline	Residence	Business	School
954 W	4,055 SW	7,336 E	20,926 E

11. Facility Annual Throughput by Quarters (percent):

Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
25 %	25 %	25 %	25 %

12. Expected Facility Operating Hours:

Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr
7	24	52	up to 8,760

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? [ ] Yes [x] No

14. Signature of Responsible Official:	Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle	Phone Number: (604) 623-4797	Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

 please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	140 ft	22 ft	155 F	1,637,212 acfm	71.8 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.

1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060

3. Facility or Business License Name (for equipment location): Sonoran Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe

Location UTM or Lat/Long: 714457.251E 3721605.893N

5. Contact Name/Title: Christopher J. Doyle

Email Address: Chris.Doyle@altagas.ca

Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment: natural gas-fired auxiliary boiler, 66.3 MMBtu/hr (HHV)

Air Pollution Control Equipment, if any (note that most APCE require a separate application): low-NOx burner

7. Application is for:
[x] New Construction [ ] Modification* [ ] Change of Owner*

For modification or change of owner:
*Current Permit Number: ____________

8. Type of Organization (check one):
[ ] Individual Owner [ ] Partnership [x] Corporation [ ] Utility [ ] Local Agency [ ] State Agency [ ] Federal Agency

9. General Nature of Business: Electric power generation

Principal Product: electricity

SIC Code (if known): 4911

10. Distances (feet and direction to closest):

933 S	4,025 SW	7,428 WSW	21,094 E
Fenceline	Residence	Business	School

11. Facility Annual Throughput by Quarters (percent):

25 %	25 %	25 %	25 %
Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec

12. Expected Facility Operating Hours:

7	24	52	up to 8,760
Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? [ ] Yes [x] No

14. Signature of Responsible Official:

Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle

Phone Number: (604) 623-4797

Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

 please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	50 ft	2.9 ft	600 F	28,481 acfm	71.0 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.

1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060

3. Facility or Business License Name (for equipment location): Sonoran Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe

Location UTM or Lat/Long: 7714377.684E 3721610.986N

5. Contact Name/Title: Christopher J. Doyle

Email Address: Chris.Doyle@altagas.ca

Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment: Tier 3 diesel-fueled emergency fire pump engine, nominal 268 bhp

Air Pollution Control Equipment, if any (note that most APCE require a separate application):

7. Application is for: ☒ New Construction ☐ Modification* ☐ Change of Owner*

For modification or change of owner: *Current Permit Number: ______

8. Type of Organization (check one): ☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business: Electric power generation

Principal Product: electricity

SIC Code (if known): 4911

10. Distances (feet and direction to closest):

777 W	3,797 SW	7,167 WSW	21,210 E
Fenceline	Residence	Business	School

11. Facility Annual Throughput by Quarters (percent):

25 %	25 %	25 %	25 %
Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec

12. Expected Facility Operating Hours:

7	24	52	up to 8,760
Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official:

Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle

Phone Number: (604) 623-4797

Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

 please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	10 ft	0.51 ft	848 F	1513 acfm	125.7 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT www.mdaqmd.ca.gov
14306 Park Avenue, Victorville, CA 92392-2310 *Eldon Heaston*
(760) 245-1661 Facsimile: (760) 245-2022 Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.
1a. Federal Tax ID No.:
2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060
3. Facility or Business License Name (for equipment location): Sonoran Energy Project
4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe
Location UTM or Lat/Long: 714347.221E 3721627.322N
5. Contact Name/Title: Christopher J. Doyle
Email Address: Chris.Doyle@altagas.ca
Phone/Fax Nos.: (604) 623-4797
6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment: 10-cell mechanical draft wet cooling tower
Air Pollution Control Equipment, if any (note that most APCE require a separate application): drift eliminator
7. Application is for: ☒ New Construction ☐ Modification* ☐ Change of Owner*
For modification or change of owner: *Current Permit Number: ______
8. Type of Organization (check one): ☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency
9. General Nature of Business: Electric power generation
Principal Product: electricity
SIC Code (if known): 4911
10. Distances (feet and direction to closest):

Fenceline	Residence	Business	School
680 W	3,835 SW	7,058 WSW	21,030 E

11. Facility Annual Throughput by Quarters (percent):

Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
25 %	25 %	25 %	25 %

12. Expected Facility Operating Hours:

Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr
7	24	52	up to 8,760

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No
14. Signature of Responsible Official:
Official Title: Vice President
Typed or Printed Name of Responsible Official: Christopher J. Doyle
Phone Number: (604) 623-4797
Date Signed: 7/15/2015

- For District Use Only -

Application Number:	Invoice Number:	Permit Number:	Company/Facility Number:

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

Page 2 of 2: please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	41.8 ft	28.0 ft	79 F (nominal)	1,359,101 acfm	36.8 ft/sec
2	(each of 10 cells)				
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print

REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.
1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060

3. Facility or Business License Name (for equipment location): Sonoran Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe
Location UTM or Lat/Long: 714430.248E 3721680.367N

5. Contact Name/Title: Christopher J. Doyle
Email Address: Chris.Doyle@altagas.ca
Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment: selective catalytic reduction system for gas turbine/HRSG

Air Pollution Control Equipment, if any (note that most APCE require a separate application):

7. Application is for:
☒ New Construction ☐ Modification* ☐ Change of Owner*

For modification or change of owner:
*Current Permit Number: ____________

8. Type of Organization (check one):
☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business: Electric power generation
Principal Product: electricity
SIC Code (if known): 4911

10. Distances (feet and direction to closest):

954 W	4,055 SW	7,336 WSW	20,926 E
Fenceline	Residence	Business	School

11. Facility Annual Throughput by Quarters (percent):

25 %	25 %	25 %	25 %
Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec

12. Expected Facility Operating Hours:

7	24	52	up to 8,760
Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official: [signature]
Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle
Phone Number: (604) 623-4797
Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

Page 2 of 2: please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	140 ft	22 ft	155 F	1,637,212 acfm	71.8 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose. The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print — REMIT $245.00 WITH THIS DOCUMENT ($140.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): AltaGas Sonoran Energy Inc.	1a. Federal Tax ID No.:
2. Mailing/Billing Address (for above company name): 1411 Third Street, Suite A, Port Huron, MI 48060	
3. Facility or Business License Name (for equipment location): Sonoran Energy Project	
4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 15560 West Hobsonway, Blythe	Location UTM or Lat/Long: 714430.248E 3721680.367N

5. Contact Name/Title:	Email Address:	Phone/Fax Nos.:
Christopher J. Doyle	Chris.Doyle@altagas.ca	(604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment:
oxidation catalyst for gas turbine/HRSG

Air Pollution Control Equipment, if any (note that most APCE require a separate application):

7. Application is for:
☒ New Construction ☐ Modification* ☐ Change of Owner*

For modification or change of owner:
*Current Permit Number: ____________

8. Type of Organization (check one):
☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business:	Principal Product:	SIC Code (if known):
Electric power generation	electricity	4911

10. Distances (feet and direction to closest):

Fenceline	Residence	Business	School
954 W	4,055 SW	7,336 WSW	20,926 E

11. Facility Annual Throughput by Quarters (percent):

Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
25 %	25 %	25 %	25 %

12. Expected Facility Operating Hours:

Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr
7	24	52	up to 8,760

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official:	Official Title:	
[signature]	Vice President	
Typed or Printed Name of Responsible Official:	Phone Number:	Date Signed:
Christopher J. Doyle	(604) 623-4797	7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	140 ft	22 ft	155 F	1,637,212 acfm	71.8 ft/sec
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Please see application support document for additional details.

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

Appendix C

Permit Application Forms, BEP

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print REMIT $253.00 WITH THIS DOCUMENT ($145.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): Blythe Energy Inc.

1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): P.O. Box 1210

3. Facility or Business License Name (for equipment location): Blythe Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 385 N. Buck Blvd.

Location UTM or Lat/Long: (m) 714609 (E) / 3721719 (N)

5. Contact Name/Title: Christopher J. Doyle

Email Address: Chris.Doyle@altagas.ca

Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment:
Reductions in permitted emissions limits for existing Siemens F Class V84.3A(2) gas turbine with duct-fired heat recovery steam generator

Air Pollution Control Equipment, if any (note that most APCE require a separate application):
Selective Catalytic Reduction (SCR) and Oxidation Catalyst

7. Application is for:
☐ New Construction ☒ Modification* ☐ Change of Owner*

For modification or change of owner:
*Current Permit Number: B007953

8. Type of Organization (check one):
☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business: Electric Power Generation

Principal Product: Electricity

SIC Code (if known): 4911

10. Distances (feet and direction to closest):

624 N	4,894 SW	7,878 WSW	19,992 E
Fenceline	Residence	Business	School

11. Facility Annual Throughput by Quarters (percent):

25 %	25 %	25 %	25 %
Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec

12. Expected Facility Operating Hours:

24	7	52	8,760
Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official:

Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle

Phone Number: (604) 623-4797

Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	130 ft.	19 ft.	170 F	1,009,505 acfm	59.3 fps (estimate)
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
Stack Diameter is the diameter (or equivalent circular diameter) of discharge point (nearest tenth foot)
If using cross-sectional area (A in square feet), equivalent diameter is D = (1.273A)^0.5
Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
Exhaust Flow Rate at discharge point in actual cubic feet per minute (ACFM)
Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Blythe Energy proposes to reduce the hourly PM10 mass emission limit for the two existing Siemens F Class V84.3A(2) gas turbines, to add a new annual average fuel sulfur limit, and to reduce the facilitywide annual mass emissions limits for SOx and PM10 in the current Permit to Operate (PTO).

If you wish to specify process information as proprietary or confidential, space is provided for this purpose. The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
14306 Park Avenue, Victorville, CA 92392-2310
(760) 245-1661 Facsimile: (760) 245-2022

www.mdaqmd.ca.gov
Eldon Heaston
Executive Director

APPLICATION FOR AUTHORITY TO CONSTRUCT AND PERMIT TO OPERATE

Page 1 of 2: please type or print — REMIT $253.00 WITH THIS DOCUMENT ($145.00 FOR CHANGE OF OWNER)

1. Permit To Be Issued To (company name to receive permit): Blythe Energy Inc.
1a. Federal Tax ID No.:

2. Mailing/Billing Address (for above company name): P.O. Box 1210

3. Facility or Business License Name (for equipment location): Blythe Energy Project

4. Facility Address - Location of Equipment (if same as for company, enter "Same"): 385 N. Buck Blvd.
Location UTM or Lat/Long: (m) 714609 (E) / 3721719 (N)

5. Contact Name/Title: Christopher J. Doyle
Email Address: Chris.Doyle@altagas.ca
Phone/Fax Nos.: (604) 623-4797

6. Application is hereby made for Authority To Construct (ATC) and Permit To Operate (PTO) the following equipment:
Reductions in permitted emissions limits for existing Siemens F Class V84.3A(2) gas turbine with duct-fired heat recovery steam generator

Air Pollution Control Equipment, if any (note that most APCE require a separate application):
Selective Catalytic Reduction (SCR) and Oxidation Catalyst

7. Application is for:
☐ New Construction ☒ Modification* ☐ Change of Owner*
For modification or change of owner: *Current Permit Number: B007954

8. Type of Organization (check one):
☐ Individual Owner ☐ Partnership ☒ Corporation ☐ Utility ☐ Local Agency ☐ State Agency ☐ Federal Agency

9. General Nature of Business: Electric Power Generation
Principal Product: Electricity
SIC Code (if known): 4911

10. Distances (feet and direction to closest):
525 N Fenceline — 4,950 SW Residence — 7,889 WSW Business — 19,907 E School

11. Facility Annual Throughput by Quarters (percent):

Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
25 %	25 %	25 %	25 %

12. Expected Facility Operating Hours:

Hrs/Day	Days/Wk	Wks/Yr	Total Hrs/Yr
24	7	52	8,760

13. Do you claim Confidentiality of Data (if yes, state nature of data on reverse in Remarks)? ☐ Yes ☒ No

14. Signature of Responsible Official: [signature]
Official Title: Vice President

Typed or Printed Name of Responsible Official: Christopher J. Doyle
Phone Number: (604) 623-4797
Date Signed: 7/15/2015

- For District Use Only -

Application Number:	*Invoice Number:*	*Permit Number:*	*Company/Facility Number:*

MOJAVE DESERT AIR QUALITY MANAGEMENT DISTRICT
GENERAL APPLICATION, continued

 please type or print

15. Stack Emissions Information:

Stack No.	Stack Height	Stack Diameter	Exhaust Temp	Exhaust Flow Rate	Exhaust Velocity
1	130 ft.	19 ft.	170 F	1,009,505 acfm	59.3 fps (estimate)
2					
3					

(list additional stacks on a separate sheet)

Stack Height is the distance above ground level to discharge point (feet)
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Exhaust Temp in degrees F, acutal or estimated to nearest 50 deg F
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Exhaust Velocity in feet per second, design or measured

16. Remarks (basis for confidentiality of data, process description, modification description, etc.):

Blythe Energy proposes to reduce the hourly PM10 mass emission limit for the two existing Siemens F Class V84.3A(2) gas turbines, to add a new annual average fuel sulfur limit, and to reduce the facilitywide annual mass emissions limits for SOx and PM10 in the current Permit to Operate (PTO).

If you wish to specify process information as proprietary or confidential, space is provided for this purpose.
The kinds and rates of emissions may not be held confidential; emissions are subject to public disclosure.

Mojave Desert Air Quality Management District

TITLE V – PERMIT AMENDMENT / MODIFICATION

I. PERMIT ACTION (Check appropriate box)

☐ ADMINISTRATIVE AMENDMENT ☐ MINOR MODIFICATION ☒ SIGNIFICANT MODIFICATION

☐ OFF-PERMIT CHANGE

1. FACILITY NAME: Blythe Energy Project	
2. FACILITY ID: 1000 0018 0181	
3. TITLE V PERMIT NO: 130202262	
4. TYPE OF ORGANIZATION: ☒ Corporation ☐ Sole Ownership ☐ Government ☐ Partnership ☐ Utility	
5. COMPANY NAME: Blythe Energy Inc.	
6. COMPANY MAILING/BILLING ADDRESS: STREET/P.O. BOX: P.O. Box 1210 CITY: Blythe STATE: California 9-DIGIT ZIP CODE: 92226	
7. FACILITY ADDRESS: STREET: 385 N. Buck Blvd. CITY: Blythe STATE: California 9-DIGIT ZIP CODE: 92225	PROPOSED DATE OF INSTALLATION: N/A
8. DISTANCES (FEET AND DIRECTION) TO CLOSEST: FENCELINE: 490 N RESIDENCE: 3,960 SW BUSINESS: 5,280 W SCHOOL: 25,112 E	
9. GENERAL NATURE OF BUSINESS: Electric Power Generation	
10. DESCRIPTION OF EQUIPMENT OR MODIFICATION FOR WHICH APPLICATION IS MADE (include Permit #'s if known, and use additional sheets if necessary) Blythe Energy proposes to pcbsac rfc fmspjw NK/. k_qq ckgqqgml jgkgr dmp rfc rum cvgqrgle Qgckclq D Aj_qq T62,1?&0' e_qrsp`glcq* rm _bb _ new annual average fuel sulfur limit, and to reduce the facilitywide annual mass emissions limits for SOx and PM10 in the current Title V operating permit.	
11. PERSON TO CONTACT FOR INFORMATION ON THIS APPLICATION: NAME: Christopher J. Doyle PHONE NUMBER: 604-623-4797 TITLE: Vice President EMAIL: Chris.Doyle@altagas.ca	

II. COMPLIANCE CERTIFICATION (Read each statement carefully and check all for confirmation):

[X] Based on information and belief formed after reasonable inquiry, the equipment identified in this application will continue to comply with the applicable federal requirement(s).

[X] Based on information and belief formed after reasonable inquiry, the equipment identified in this application will comply with applicable federal requirement(s) that will become effective during the permit term, on a timely basis.

[X] Corrected information will be provided to the District when I become aware that incorrect or incomplete information has been submitted.

[X] Based on information and belief formed after reasonable inquiry, information and statements in the submitted application package, including all accompanying reports, and required certifications are true accurate and complete.

I declare, under penalty of perjury under the laws of the state of California, that the forgoing is correct and true:

Signature of Responsible Official — Date 7/27/16

Christopher J. Doyle
Name of Responsible Official (please print)

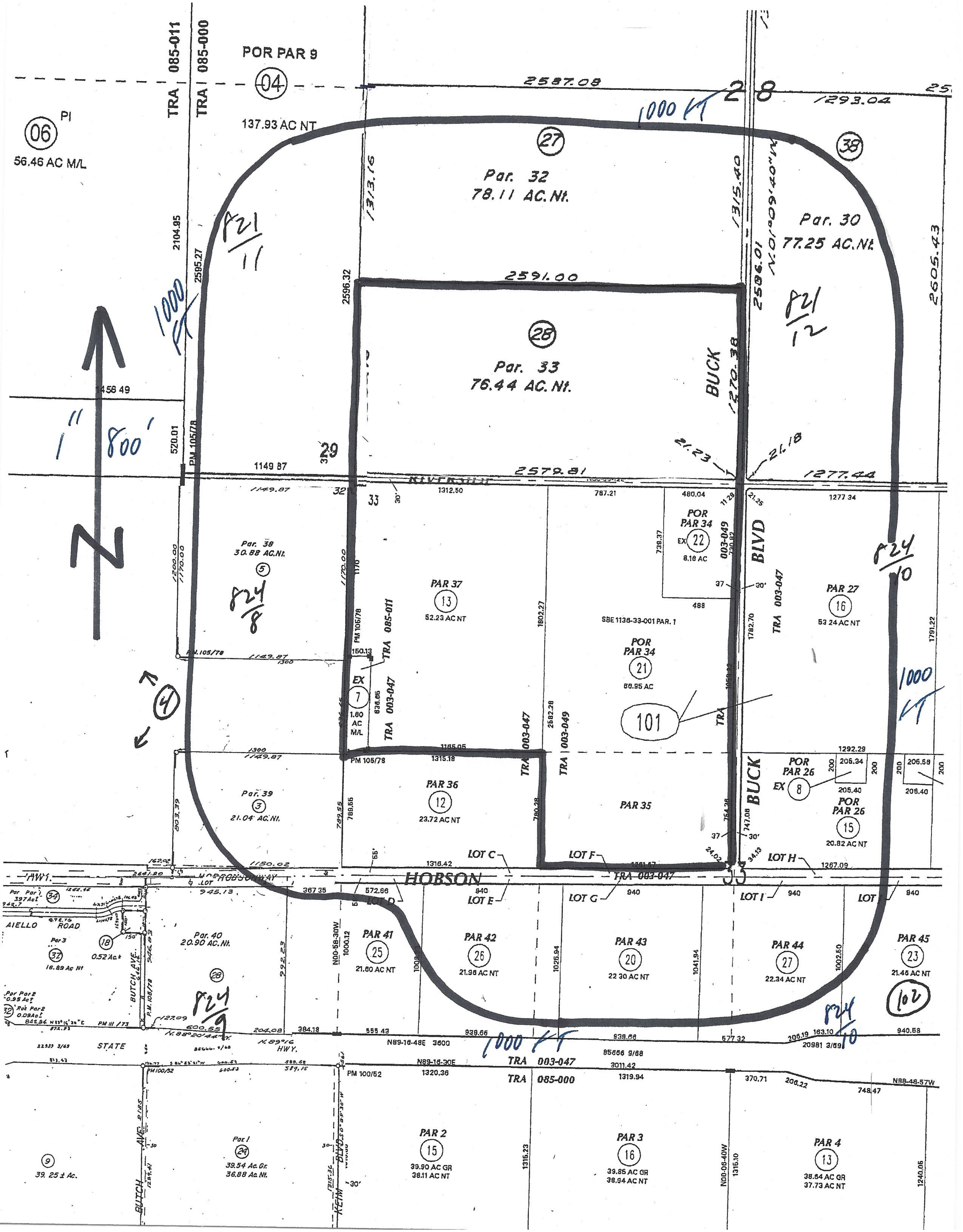
Vice President
Title of Responsible Official (please print)

For AQMD Use Only:

DATE STAMP	DISTRICT PERMIT APPLICATION NO:	COMPANY /FACILITY ID:

APPENDIX B

Property Owners Within 1,000 Feet of the Project Site



POR PAR 9
04
137.93 AC NT
06
56.46 AC M/L
TRA 085-011
TRA 085-000
2587.08
1000 FT
28
1293.04
27
38
Par. 32
78.11 AC. Nt.
Par. 30
77.25 AC. Nt.
821/11
821/12
2591.00
28
Par. 33
76.44 AC. Nt.
BUCK
1" 800'
29
2579.81
1277.44
Par. 38
30.88 AC. Nt.
824/8
PAR 37
13
52.23 AC NT
POR PAR 34
22
8.16 AC
BLVD
PAR 27
16
53.24 AC NT
824/10
SBE 1136-33-001 PAR. 1
POR PAR 34
21
66.95 AC
101
1000 FT
EX 7
1.60 AC M/L
TRA 003-047
TRA 003-049
Par. 39
21.04 AC. Nt.
PAR 36
12
23.72 AC NT
PAR 35
BUCK
POR PAR 26
EX 8
POR PAR 26
15
20.82 AC NT
LOT C
LOT F
LOT H
HOBSON
HOBSON WAY
LOT D
LOT E
LOT G
LOT I
LOT J
AIELLO ROAD
BUTCH AVE.
Par. 40
20.90 AC. Nt.
PAR 41
25
21.60 AC NT
PAR 42
26
21.96 AC NT
PAR 43
20
22.30 AC NT
PAR 44
27
22.34 AC NT
PAR 45
23
21.46 AC NT
102
824/9
824/10
1000 FT
STATE HWY.
TRA 003-047
TRA 085-000
BUTCH AVE.
KEITH BLVD
Par 1
24
39.54 Ac. Gr.
36.88 Ac. Nt.
PAR 2
15
39.90 AC GR
38.11 AC NT
PAR 3
16
39.85 AC GR
38.94 AC NT
PAR 4
13
38.64 AC GR
37.73 AC NT
9
39.25 ± Ac.

APN_D	FIRSTNAME	LASTNAME	TITLE	ORG	ADDRESS	ADDRESS_2	CITY	STATE	ZIP
821-110-004				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
821-120-027				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
821-120-028				ALTAGAS POWER HOLDINGS US INC	1411 THIRD ST #A		PORT HURON	MI	48060
821-120-038				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-080-003				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-080-003				OCCUPANT	15550 W HOBSON WAY		BLYTHE	CA	92225
824-080-004				COUNTY OF RIVERSIDE	P.O. BOX 1180		RIVERSIDE	CA	92502
824-080-004				OCCUPANT	16870 W HOBSON WAY		BLYTHE	CA	92225
824-080-005				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-101-007				COUNTY OF RIVERSIDE	P.O. BOX 1180		RIVERSIDE	CA	92502
824-101-012				ALTAGAS SONORAN ENERGY Inc.	1411 THIRD ST #A		PORT HURON	MI	48060
824-101-013				ALTAGAS SONORAN ENERGY Inc.	1411 THIRD ST #A		PORT HURON	MI	48060
824-101-015				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-101-016				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-101-021				BLYTHE ENERGY	P.O. BOX 1210		BLYTHE	CA	92226
824-101-021				OCCUPANT	385 N BUCK BLVD		BLYTHE	CA	92225
824-101-022				USA	P.O. BOX 281213		LAKEWOOD	CO	80228
824-102-020				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-102-026				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036
824-102-027				GILA FARM LAND LLC	113 S LA BREA AVE		LOS ANGELES	CA	90036