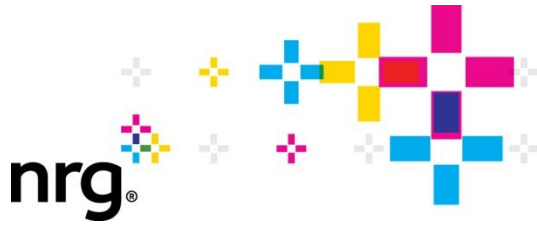


## DOCKETED

|                         |   |
|-------------------------|---|
| <b>Docket Number:</b>   | 15-AFC-01   |
| <b>Project Title:</b>   | Puente Power Project  |
| <b>TN #:</b>            | 215396  |
| <b>Document Title:</b>  | Applicant's Responses to Information Requested by VCAPCD re Application for Authority to Construct/ Determination of Compliance |
| <b>Description:</b>     | Letter dated 5/15/15  |
| <b>Filer:</b>           | Paul Kihm   |
| <b>Organization:</b>    | Latham & Watkins LLP  |
| <b>Submitter Role:</b>  | Applicant Representative  |
| <b>Submission Date:</b> | 1/15/2017 12:32:22 PM   |
| <b>Docketed Date:</b>   | 1/17/2017   |



NRG Energy Center Oxnard LLC  
5790 Fleet Street, Suite 200  
Carlsbad, CA 92008  
Phone: 760-710-2156  
Fax: 760-710-2158

May 15, 2015

Kerby E. Zozula  
Manager, Engineering Division  
Ventura County Air Pollution Control District  
669 County Square Drive, 2<sup>nd</sup> Floor  
Ventura, CA 93003

Subject: Application for an Authority to Construct/Determination of Compliance for the Proposed Puente Power Project (P3)

Dear Mr. Zozula:

NRG Energy Center Oxnard LLC is pleased to submit the following responses to the information requested in Ventura County Air Pollution Control District's (VCAPCD) April 15, 2015 letter regarding the March 19, 2015 Authority to Construct (ATC)/Determination of Compliance (DOC) application package (Application 00013-370) for the proposed Puente Power Project (P3).

Request 1: Pursuant to Rule 26.6C and Rule 26.2.B.4, please provide monthly fuel use data for 2010 through 2014 for the following existing equipment in order to calculate the quarterly profile for the actual emission reductions:

- East Steam Generator No. 1 and No. 2 at the Mandalay Generating Station
- The 201 BHP emergency diesel generator engine
- The 154 BHP emergency diesel firewater pump engine

*Response:* The monthly fuel use data from 2010 through 2014 for the existing combustion equipment at the Mandalay Generating Station are included in Attachment 1.

Request 2: Your project will require offsets pursuant to Rule 26.2.B. Please identify the specific offsets proposed for this project and identify if they will be "surplus at the time of use" as defined in Rule 26.11.

*Response:* The NOx emission reduction credits (ERCs) totaling approximately 52.7 tons/year that will be used for the P3 (on an as-needed basis) are Southern California Edison Company ERC certificate numbers 1078, 1079, 1080, 1083, 1084, 1085, 1091, 1092, 1094, 1097, 1104, 1107, and 1109. With

regard to the amount of these ERCs that will be “surplus at the time of use,” under Rule 26.11.C.6 this ERC surplus determination is not required for permitting actions occurring during periods when the annual equivalency demonstrations prepared by the VCAPCD show a positive balance. We note that the April 2014 annual equivalency demonstration prepared by the VCAPCD showed a positive year-end balance of 53.27 tons per year of ROC and 33.37 tons per year of NOx. Based on this result, new major sources and major modifications are exempt from the NOx/ROC ERC surplus determination until the submission of the next annual equivalency demonstration. While the results of the 2015 annual equivalency demonstration may show that an ERC surplus determination is not necessary for the P3, we are currently in the process of collecting the necessary background information on the above ERCs to make this determination. We expect to have this analysis completed within approximately two weeks and will submit the results to the VCAPCD at that time.

Request 3: As required by Rule 26.2.D, please provide a certification of statewide compliance.

*Response:* Enclosed as Attachment 2 is the statewide compliance certification letter.

Request 4: As required by Rule 26.2.E, please provide the analysis of alternatives for the project.

*Response:* An analysis of alternatives was included as Section 5 of the Application for Certification (AFC) for the P3 filed with the California Energy Commission on April 15, 2015. An electronic copy of the AFC is included in the enclosed compact disc. Section 5 of the AFC is provided as Attachment 3.

Request 5: You have proposed that the installation of the new GE H-Class natural gas-fired, simple-cycle gas turbine meets the definition of “replacement emissions unit” in Rule 26.1. In order to better understand your proposal, please compare and contrast the electrical functions of the new gas turbine engine, existing Steam Generator Nos. 1 and 2, existing Turbine Peaking Unit No. 3, and the existing nearby McGrath Beach Turbine Peaking Unit owned and operated by Southern California Edison.

*Response:* Provided below is a summary of the electrical functions of Mandalay Units 1-3, the McGrath Peaking Unit, and the proposed new H-Class combustion turbine generator (CTG).

- Mandalay Units 1 and 2 and the New H-Class CTG: Mandalay Units 1 and 2 are natural gas-fired steam boiler generating units with a combined nominal generating capacity of approximately 430 MW (net). The proposed new unit is a natural gas-fired simple-cycle CTG with a nominal generating capacity of approximately 262 MW (net). As is the case with Units 1 and 2, the new CTG will be connected to the SCE 220-kV switchyard (located adjacent to the project site). This switchyard is connected to the SCE Santa Clara substation, which is part of the high-voltage grid system serving the Big Creek/Ventura local reliability area. The new CTG will perform the same electrical function as is currently being performed by Mandalay Units 1 and 2. This function is to provide dispatchable power to the high-voltage 220-kV system mainly to provide voltage support to the Big Creek/Ventura local reliability area and to meet long-term capacity requirements. This voltage support is necessary to help maintain the grid stability needed due

to the intermittent operating nature of renewable generating sources (i.e., wind and solar power). The identical function of the new CTG and Mandalay Units 1 and 2 is supported by the similar number of annual startups and operating hours for the new and existing units. The new CTG is expected to undergo approximately 200 startups per year and be operated a total of approximately 2,453 hours per year. Over the past five years (2010 to 2014), Mandalay Units 1 and 2 have undergone a combined average of approximately 175 startups per year and operated a total of approximately 2,370 hours per year (these are hours synchronized to the grid). The advantage of the new CTG is that it can provide this grid support more efficiently by burning less fuel on a per-MW basis, with a faster response time, and with lower maintenance costs compared to Mandalay Units 1 and 2.

- Mandalay Unit 3 and the McGrath Peaking Unit: Mandalay Unit 3 is a natural gas-fired simple-cycle CTG with a nominal generating capacity of approximately 130 MW (net). The existing SCE McGrath Peaking Unit is a natural gas-fired simple-cycle CTG with a nominal generating capacity of approximately 47 MW. Both Mandalay Unit 3 and the McGrath Peaking Unit are connected to the SCE 66-kV switchyard (located on the east side of North Harbor Blvd from the project site). This switchyard is connected to several SCE substations including the Santa Clara, Silver Strand, Gonzales, and San Miguel substations. Both Mandalay Unit 3 and the McGrath Peaking Unit provide the same electrical function, which is to provide local grid support due to system upsets such as the sudden loss of a generating unit or failure of a transmission line. Both units were designed with black start capability (i.e., the ability to startup without utility power) to help bring the grid back on-line due to a total system failure. It should be noted that while Mandalay Unit 3 is designed for black start capability, it would likely require the replacement of startup batteries for this unit to actually be able to achieve a black start. Due to the type of support provided to the grid, both Mandalay Unit 3 and the McGrath Peaking Unit will operate a limited number of hours per year. For example, over the past five years (2010 to 2014) Mandalay Unit 3 has undergone an average of approximately 22 startups per year and operated a total of approximately 60 hours per year (these are hours synchronized to the grid). Because Mandalay Unit 3 is an older-generation CTG compared to the McGrath Peaking Unit, the McGrath Peaking Unit would be more efficient to operate compared to Unit 3.

In addition to the above responses, please note that the screening-level health risk assessment (HRA) results in the April 15, 2015 AFC (see Section 4.9 - Public Health) are based on the recently issued HARP2 model, whereas the HRA results in the March 19, 2015 ATC/DOC permit application package were based on the earlier version of the HARP model. Therefore, we request that the VCAPCD use the HRA results in the AFC. The detailed HARP2 modeling files are included in the enclosed air quality modeling compact disc. This disc also includes the criteria pollutant modeling files, which are identical to the files submitted as part of the ATC/DOC permit application package.

It is our intention that the additional information provided will enable VCAPCD to issue a "completeness determination" with respect to Authority to Construct Application No, 00013-370. Such a letter will assist in meeting the CEC's Data Adequacy determination that is currently pending. CEC Data Adequacy is an important milestone in the processing of the AFC.

For the purposes of deeming the P3 ATC/DOC application package complete, we believe the VCAPCD can complete its completeness determination based on our application and the additional information

Mr. Kerby Zozula, VCAPCD

May 15, 2015

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we have provided herein. If you have any questions or need any additional information, please do not hesitate to contact me at 760-710-2156 or Tom Andrews of Sierra Research at 916-273-5139.

Sincerely,

A handwritten signature in black ink that reads "George L. Piantka". The signature is written in a cursive style with a large initial "G".

George L. Piantka, PE

Director, Regulatory Environmental Services

NRG West Region

Attachments

cc: Jon Hilliard, CEC  
Gerry Bemis, CEC  
CEC Dockets (15-AFC-01)  
Leonard Scandura, SJVAPCD  
Leland Villalvazo, SJVAPCD  
Tom Andrews, Sierra Research  
Michael J. Carroll, Latham & Watkins  
Anne Connell, AECOM

ATTACHMENT 1

MONTHLY FUEL USE SUMMARIES FOR MANDALAY  
GENERATING STATION (2010 To 2014)

**2010 Mandalay Generating Station Fuel Use**

| Equipment                           | January | February | March | April | May | June | July  | August | September | October | November | December | Annual Total |
|-------------------------------------|---------|----------|-------|-------|-----|------|-------|--------|-----------|---------|----------|----------|--------------|
| Unit 1 (MMscf)                      | 4.8     | 23.7     | 0.0   | 0.4   | 0.0 | 0.7  | 83.8  | 106.5  | 19.7      | 34.6    | 14.7     | 25.4     | 314.3        |
| Unit 2 (MMscf)                      | 77.3    | 23.1     | 0.6   | 0.0   | 0.0 | 0.9  | 178.7 | 127.4  | 59.1      | 73.6    | 22.6     | 24.4     | 587.6        |
| Unit 3 (MMscf)                      | 0.7     | 1.7      | 0.0   | 1.4   | 0.5 | 2.5  | 5.7   | 7.2    | 12.4      | 7.1     | 2.9      | 0.1      | 42.4         |
| Emergency Gen. Engine (gallons)     | 15.2    | 0.0      | 0.4   | 0.0   | 0.4 | 0.4  | 0.4   | 1.1    | 0.4       | 0.4     | 0.4      | 0.4      | 19.5         |
| Emergency Firepump Engine (gallons) | 0.3     | 0.3      | 0.3   | 0.0   | 0.0 | 0.3  | 0.6   | 0.6    | 0.3       | 0.3     | 0.3      | 0.6      | 3.8          |

**2011 Mandalay Generating Station Fuel Use**

| Equipment                           | January | February | March | April | May   | June | July | August | September | October | November | December | Annual Total |
|-------------------------------------|---------|----------|-------|-------|-------|------|------|--------|-----------|---------|----------|----------|--------------|
| Unit 1 (MMscf)                      | 82.5    | 0.0      | 0.0   | 6.2   | 0.0   | 53.6 | 91.0 | 50.1   | 50.2      | 0.0     | 0.6      | 0.0      | 334.2        |
| Unit 2 (MMscf)                      | 100.9   | 4.8      | 0.0   | 74.7  | 110.0 | 19.0 | 0.0  | 53.1   | 67.0      | 29.0    | 35.3     | 13.9     | 507.8        |
| Unit 3 (MMscf)                      | 0.0     | 0.0      | 1.4   | 2.7   | 5.0   | 9.6  | 2.1  | 0.0    | 4.3       | 2.6     | 2.6      | 0.0      | 30.4         |
| Emergency Gen. Engine (gallons)     | 0.4     | 0.7      | 0.4   | 0.4   | 1.1   | 0.7  | 0.0  | 0.7    | 0.4       | 0.4     | 0.4      | 0.4      | 5.9          |
| Emergency Firepump Engine (gallons) | 0.3     | 0.6      | 0.3   | 0.6   | 0.3   | 0.6  | 0.3  | 0.3    | 0.3       | 0.3     | 0.3      | 0.3      | 4.4          |

**2012 Mandalay Generating Station Fuel Use**

| Equipment                           | January | February | March | April | May   | June | July  | August | September | October | November | December | Annual Total |
|-------------------------------------|---------|----------|-------|-------|-------|------|-------|--------|-----------|---------|----------|----------|--------------|
| Unit 1 (MMscf)                      | 49.0    | 22.3     | 0.5   | 0.0   | 83.9  | 49.9 | 155.9 | 387.5  | 79.1      | 106.7   | 143.7    | 61.7     | 1140.2       |
| Unit 2 (MMscf)                      | 0.3     | 0.0      | 0.0   | 16.6  | 106.5 | 74.1 | 86.1  | 380.2  | 269.9     | 101.7   | 89.1     | 42.1     | 1166.5       |
| Unit 3 (MMscf)                      | 0.1     | 0.3      | 0.0   | 12.5  | 7.1   | 9.4  | 7.3   | 5.7    | 24.9      | 13.7    | 9.8      | 18.7     | 109.6        |
| Emergency Gen. Engine (gallons)     | 0.4     | 0.0      | 0.4   | 0.4   | 0.4   | 0.7  | 0.4   | 0.4    | 0.0       | 0.4     | 0.0      | 0.4      | 3.7          |
| Emergency Firepump Engine (gallons) | 0.3     | 0.3      | 0.6   | 0.0   | 0.0   | 0.6  | 0.0   | 0.0    | 0.3       | 0.3     | 0.0      | 0.3      | 2.6          |

**2013 Mandalay Generating Station Fuel Use**

| Equipment                           | January | February | March | April | May   | June  | July  | August | September | October | November | December | Annual Total |
|-------------------------------------|---------|----------|-------|-------|-------|-------|-------|--------|-----------|---------|----------|----------|--------------|
| Unit 1 (MMscf)                      | 143.6   | 0.6      | 0.0   | 0.0   | 127.0 | 125.4 | 122.7 | 46.8   | 71.5      | 48.8    | 191.9    | 184.8    | 1063.2       |
| Unit 2 (MMscf)                      | 104.4   | 14.6     | 201.6 | 141.5 | 178.1 | 151.9 | 97.6  | 67.1   | 86.1      | 37.8    | 158.5    | 189.8    | 1429.0       |
| Unit 3 (MMscf)                      | 8.5     | 5.5      | 4.7   | 0.1   | 4.1   | 0.2   | 2.2   | 21.4   | 19.8      | 0.0     | 0.0      | 0.9      | 67.5         |
| Emergency Gen. Engine (gallons)     | 0.7     | 0.4      | 0.4   | 0.7   | 0.0   | 0.7   | 0.7   | 0.4    | 0.4       | 0.4     | 0.4      | 0.4      | 5.6          |
| Emergency Firepump Engine (gallons) | 0.0     | 0.0      | 0.0   | 0.0   | 0.0   | 0.0   | 0.0   | 0.0    | 0.6       | 0.3     | 0.6      | 0.6      | 2.0          |

**2014 Mandalay Generating Station Fuel Use**

| Equipment                           | January | February | March | April | May  | June | July | August | September | October | November | December | Annual Total |
|-------------------------------------|---------|----------|-------|-------|------|------|------|--------|-----------|---------|----------|----------|--------------|
| Unit 1 (MMscf)                      | 89.0    | 19.7     | 6.0   | 60.8  | 37.9 | 9.4  | 25.8 | 41.4   | 70.3      | 191.9   | 86.7     | 108.3    | 747.2        |
| Unit 2 (MMscf)                      | 143.8   | 79.6     | 3.4   | 130.7 | 41.6 | 9.1  | 47.1 | 50.3   | 40.0      | 183.0   | 42.6     | 57.6     | 828.9        |
| Unit 3 (MMscf)                      | 0.9     | 2.3      | 1.5   | 1.4   | 1.3  | 0.0  | 4.6  | 4.5    | 2.9       | 0.0     | 0.9      | 1.5      | 21.8         |
| Emergency Gen. Engine (gallons)     | 0.0     | 2.3      | 2.3   | 3.5   | 10.5 | 1.2  | 1.2  | 2.3    | 1.2       | 1.2     | 1.2      | 1.2      | 28.1         |
| Emergency Firepump Engine (gallons) | 0.0     | 0.7      | 0.7   | 0.7   | 0.7  | 0.7  | 0.0  | 1.4    | 0.7       | 0.7     | 0.7      | 0.7      | 7.7          |

ATTACHMENT 2

STATEWIDE COMPLIANCE CERTIFICATION LETTER





**NRG Energy Center Oxnard LLC**  
5790 Fleet Street, Suite 200  
Carlsbad, CA 92008  
Phone: 760-710-2156  
Fax: 760-710-2158

May 13, 2015

Mr. Mike Villegas  
Air Pollution Control Officer  
Ventura County Air Pollution Control District  
669 County Square Drive, 2nd Floor  
Ventura, CA 93003

**Subject:** Puente Power Project – VCAPCD Rule 26.2.D Statewide Compliance Certification,  
Determination of Compliance

Dear Mr. Villegas,

In accordance with VCAPCD Rule 26.2.D, Statewide Compliance Certification, NRG Energy, Inc. is pleased to provide this compliance statement regarding the proposed Puente Power Project, which is owned by an NRG Energy, Inc. subsidiary, NRG Energy Center Oxnard LLC.

All major stationary sources in California owned or operated by NRG Energy, Inc., or by any entity controlling, controlled by, or under common control with NRG Energy, Inc., and which are subject to emission limitations, are currently in compliance or on a schedule for compliance with all applicable federal Clean Air Act emission limitations and standards. These sources include the following facilities:

- Coolwater Generating Station, Daggett, CA
- El Cajon Combustion Turbine Facility, El Cajon, CA
- Ellwood Generating Station, Goleta, CA
- El Segundo Generating Station, El Segundo, CA
- Encina Power Station, Carlsbad, CA
- Etiwanda Generating Station, Rancho Cucamonga, CA
- Kearny Mesa 1 Facility, San Diego, CA
- Kearny Mesa 2 and 3 Facility, San Diego, CA
- Long Beach Generating Station, Long Beach, CA
- Mandalay Generating Station, Oxnard, CA
- Marsh Landing Generating Station, Antioch, CA
- Midway-Sunset, Fellows, CA (50% owned; not Title V permit holder)
- Miramar Facility, San Diego, CA
- Ormond Beach Generating Station, Oxnard, CA
- Pittsburg Generating Station, Pittsburg, CA
- San Diego District Energy Center, San Diego, CA
- San Francisco Thermal, San Francisco, CA
- Sunrise Power Company, Fellows, CA
- Walnut Creek Energy Park, Industry, CA
- Watson Cogeneration, Wilmington, CA (49% owned; not Title V permit holder)

Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

Please contact George Piantka at 760-710-2156 if you have any questions regarding this certification.

Best Regards,



John Chillemi  
President

cc: Kerby Zozula, VCAPCD  
Leonard Scandura, SJVAPCD  
Leland Villavazo, SJVAPCD  
Jon Hilliard, CEC  
Gerry Bemis, CEC  
George Piantka, NRG  
Sean Beatty, NRG  
Michael Carroll, Latham & Watkins  
Tom Andrews, Sierra Research

ATTACHMENT 3

SECTION 5, ALTERNATIVES – PUENTE POWER PROJECT  
APPLICATION FOR CERTIFICATION



# Application for Certification

## Puente Power Project (P3)

Oxnard, CA

### Volume I



Submitted to:  
**The California Energy Commission**



Prepared by: **AECOM**

## 5.0 ALTERNATIVES

### 5.1 INTRODUCTION

The California Environmental Quality Act (CEQA) requires environmental documents to consider “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives” (14 California Code of Regulations [CCR] 15126.6[a]). Therefore, the focus of an alternatives analysis should be on alternatives that “could feasibly accomplish most of the basic objectives of the project and could avoid or substantially lessen one or more of the significant effects” (14 CCR 15126.6(c)). The CEQA Guidelines further provide that “[a]mong the factors that may be used to eliminate alternatives from detailed consideration in an EIR [Environmental Impact Report] are: (i) failure to meet most of the basic project objectives, (ii) infeasibility, or (iii) inability to avoid significant environmental impacts” (14 CCR 15126.6(c)).

A range of reasonable alternatives to the proposed Puente Power Project (P3 or project), or certain elements thereof, is identified and evaluated in this section. These alternatives include:

- The “No Project” alternative (that is, not developing a new power generation facility);
- Alternative generation technologies and configurations;
- Alternative sources of water supply;
- Alternative wastewater handling systems; and
- Alternative emission control technologies.

### 5.2 PROJECT OBJECTIVES

Applicant has identified several basic objectives for the development of P3:

- Fulfill Applicant’s obligations under its 20-year Resource Adequacy Purchase Agreement (RAPA) with Southern California Edison (SCE) requiring development of 262 megawatts (MW) nominal net output of newer, more flexible and efficient natural gas generation at the site of the existing Mandalay Generating Station (MGS);
- Provide an efficient, reliable, and predictable power supply by using a simple-cycle, natural-gas-fired combustion turbine to replace the existing once-through cooling (OTC) generation;
- Support the local capacity requirements of the California Independent System Operator Big Creek/Ventura Local Capacity Reliability area;
- Develop a 262-MW nominal net power generation plant that provides efficient operational flexibility with rapid-start and fast-ramping capability to allow for efficient integration of renewable energy sources in the California electrical grid;
- Be designed, permitted, built, and commissioned by June 1, 2020;
- Minimize environmental impacts and development costs by developing on an existing brownfield site and reusing existing transmission, water, wastewater, and natural gas infrastructure;
- Site the project on property that has an industrial land use designation with consistent zoning; and
- Safely produce electricity without creating significant environmental impacts.

Project objectives play an important role in determining what constitutes a range of reasonable alternatives to the proposed project. “Under the case law applying CEQA’s definition of feasibility, ‘[al]though a lead agency may not give a project’s purpose an artificially narrow definition, a lead agency may structure its EIR alternative analysis around a reasonable definition of underlying purpose and need not study alternatives that cannot achieve that basic goal.’” *Surfrider Found. v. State Water Res. Control Bd.* (2012) 211 Cal. App. 4th 557, 583 (citation omitted). Furthermore, what constitutes a reasonable range of alternatives must be determined in light of the specific context and circumstances under which a project is proposed. “CEQA establishes no categorical legal imperative as to the scope of alternatives to be analyzed in an EIR. Each case must be evaluated on its facts, which in turn must be reviewed in light of the statutory purpose.’ ... There is no ironclad rule governing the nature or scope of the alternatives to be discussed other than the rule of reason.” *Watsonville Pilots Assn. v. City of Watsonville* (2010) 183 Cal. App. 4th 1059, 1086 [citations omitted].

Although all of the project objectives should be taken into consideration when evaluating alternatives to the proposed project, the first project objective identified above is particularly important. It reflects the context in which the State of California plans for and procures its electricity supply. The RAPA is the end result of the California Public Utility Commission’s (CPUC) Long-Term Procurement Plan; CPUC decisions authorizing the procurement of electricity by the state’s investor-owned utilities; and the Request for Offers (RFO) process conducted pursuant to those authorizations. Through the RFO process, the utility evaluates a range of alternatives and awards RAPAs that are technology-specific and location-specific to those projects best suited to meet its needs. The RAPAs are then reviewed and approved by the CPUC. It is then incumbent upon the developer to deliver the project consistent with the terms of the RAPA. Therefore, this objective is not merely a goal or aspiration of the project developer, but a legal imperative. This must be kept in mind when determining what constitutes a range of reasonable alternatives, as well as which alternatives might be considered feasible. Alternatives that fail to satisfy the first project objective are neither reasonable nor feasible, and extensive analysis of such alternatives is unwarranted.

### **5.3 NO PROJECT ALTERNATIVE**

#### **5.3.1 Description**

The No Project Alternative “provides the decision makers and the public with specific information about the environment if the project is not approved. It is a factually based forecast of the environmental impacts of preserving the status quo.” *Planning & Conservation League v. Department of Water Resources* (2000) 83 Cal. App. 4th 892, 917, 918. In this case, P3 is intended to replace the generation currently provided by MGS Units 1 and 2. Because there are currently no other gas-fired projects proposed for development in the area, in the absence of P3, MGS Units 1 and 2 may continue to be needed to meet local reliability needs. However, the State Water Resources Control Board’s (SWRCB) Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, also referred to as the OTC Policy, requires that MGS Units 1 and 2 either cease use of ocean water for cooling or reduce the impacts of OTC to a level commensurate with closed-cycle cooling by December 31, 2020. Therefore, the No Project Alternative would be MGS Units 1 and 2 continuing to operate, but with an alternative cooling system that meets the requirements of the OTC Policy.

Prior to the decision to replace MGS Units 1 and 2 with P3, a number of alternative cooling systems for MGS Units 1 and 2 were evaluated (GenOn, 2011). The Mandalay Generating Station 2011 Implementation Plan for the OTC Policy evaluated closed-cycle wet-cooling options using salt (ocean) water and fresh water, including recycled water. Due to logistical, technical, and permitting/environmental constraints, all closed-cycle wet-cooling options were determined to be infeasible. The 2011 Implementation Plan did not evaluate retrofitting MGS Units 1 and 2 with dry cooling. Ultimately, the 2011 Implementation Plan outlined compliance with the OTC Policy through implementation of

technological and/or operational measures to reduce impingement and entrainment to required levels. This approach requires a 3-year impingement and entrainment monitoring program to establish baseline conditions against which to evaluate the effectiveness of the proposed technological and/or operational measures. On May 14, 2012, the compliance strategy laid out in the 2011 Implementation Plan was changed to the current strategy of replacing MGS Units 1 and 2 with new dry-cooled generation (GenOn, 2012).

In the event that P3 did not move forward (i.e., the No Project Alternative), it would be necessary to revisit alternative OTC Policy-compliant cooling systems for MGS Units 1 and 2. The circumstances affecting the feasibility of closed-cycle wet cooling have not changed materially since development of the 2011 Implementation Plan, and those technologies continue to be infeasible. One option would be to revert to the Track 2 compliance strategy laid out in the 2011 Implementation Plan, namely implementation of technological and/or operational measures that may include variable-speed drive pumps to more efficiently manage intake flow and intake screens to reduce entrainment. However, because of the need to conduct a 3-year baseline monitoring program, after which such a strategy change would be implemented, it may not be possible to implement Track 2 prior to the compliance deadline of December 31, 2020. Therefore, notwithstanding certain engineering challenges, retrofitting MGS Units 1 and 2 with dry cooling appears to be the most viable option for bringing those units into compliance with the OTC Policy in the event that P3 does not move forward. This is, therefore, the No Project Alternative.

For the dry-cooling scenario, two ACCs, one for each unit, would be provided. Each ACC would be approximately 130 feet by 290 feet by 100 feet tall. The site would have sufficient space to accommodate this infrastructure. Process water requirements would continue to be met from the existing potable water supply. The amount of potable water would be approximately the same amount of potable water that the MGS currently uses.

### **5.3.2 Ability of No Project Alternative to Meet Project Objectives**

The No Project Alternative would meet certain project objectives. However, it would also fail to meet certain important project objectives. The No Project Alternative would not allow Applicant to fulfill its obligations under the 20-year RAPA with SCE requiring development of newer, more flexible and efficient natural gas generation. Although retrofitting MGS Units 1 and 2 with an alternative cooling system would help support the local capacity requirements, the older generating technology would not provide the same efficient operational flexibility, with rapid-start and fast ramping capability, to allow for efficient integration of renewable energy sources in the California electrical grid.

### **5.3.3 Potential Environmental Effects of No Project Alternative**

Some of the construction-related impacts associated with P3 would be eliminated with the No Project Alternative; however, there would be construction impacts associated with constructing the alternative cooling system. Because MGS Units 1 and 2 are older and less-efficient technology, the No Project Alternative would result in increased fuel and water consumption and air pollution compared to the proposed P3 project.

## **5.4 ALTERNATIVE SITES**

The proposed P3 project site is in the existing MGS site and would be constructed north of the existing power-generating facilities. The proposed site is currently undeveloped, but was previously graded. Construction of the new facility on the proposed site would capitalize on the close proximity to the existing SCE Substation, adjacent to MGS. Additionally, locating P3 within the boundaries of the existing MGS site would allow the reuse of infrastructure such as the ammonia tank, access roads, and

electrical, water, wastewater, and natural gas systems. This would eliminate the need for offsite linear facilities and minimize environmental impacts.

According to Public Resources Code (PRC) 25540.6(b), evaluation of alternative sites is not required when a natural-gas-fired thermal power plant is proposed for development at an existing industrial site such as MGS. P3 is just that type of project that was envisioned by this code section; therefore, it is reasonable not to analyze alternative sites for the project. P3 would be adjacent to the existing SCE switchyard, and because of adjacent existing infrastructure, would minimize the need for offsite linear features. Therefore, evaluation of alternative sites outside the boundaries of the MGS is not required.

In addition, as stated above, CEQA requires environmental documents to consider a range of reasonable alternatives that would feasibly attain most of the basic objectives of the project, but would avoid or substantially lessen any of the significant effects; and states that failure to do either may be grounds for elimination of an alternative. “Although CEQA requires that an EIR identify alternatives to a project, it does not expressly require a discussion of alternative project locations.” *Mira Mar Mobile Community v. City of Oceanside*, 119 Cal. App. 4th 477, 491 (2004) (citing PRC §§ 21001 (g), 21002.1(a), 21061). “[T]here is no rule requiring an EIR to explore offsite project alternatives in every case.” *California Native Plant Society v. City of Santa Cruz* (2009) 177 Cal. App. 4th 957, 991. An agency may determine that no feasible locations exist either because basic project objectives cannot be achieved at another site, or because there are no sites meeting the criteria for feasible alternative sites. See *City of Long Beach v. Los Angeles Unified Sch. Dist.*, 176 Cal. App. 4th 889, 921 (2009).

It would not be feasible to meet most of the project objectives if P3 was constructed at an alternate site. First and foremost, the RAPA awarded by SCE is location-specific and calls for new generation to be developed at the MGS site. In its RFO process, SCE evaluated numerous proposals at a variety of different locations, and selected the Applicant’s proposal at the MGS location as the proposal that best meets its needs. Applicant does not have the ability under the RAPA to select an alternative location for the development of P3. Even if Applicant had the ability to select an alternative location, doing so would not meet other project objectives, including reusing existing infrastructure to minimize development costs and environmental impacts.

Furthermore, Applicant does not have ownership or control over alternative sites on which P3 could be located, and it is unlikely that Applicant could identify, evaluate, and acquire an alternative site, including necessary rights-of-way for gas, water, and transmission infrastructure, and meet its commissioning date of June 1, 2020. “A feasible alternative is one which can be ‘accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors.’ . . . Surely whether a property is owned or can reasonably be acquired by the project proponent has a strong bearing on the likelihood of a project's ultimate cost and the chances for an expeditious and ‘successful accomplishment.’ . . . [T]he law does not require in depth review of alternatives which cannot be realistically considered and successfully accomplished . . .” *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal. 3d 553, 574–75 [internal citations omitted].

Finally, construction and operation of a power plant at an alternate location would likely result in new, significant environmental impacts associated with the additional construction and operation of infrastructure that would be required because existing plant infrastructure would not be used. This would potentially result in greater impacts related to Air Quality, Biological Resources, Cultural Resources, Hazards and Hazardous Materials, Noise, Soils, Transportation and Circulation, Visual Resources, and Water Resources.

For the reasons set forth above, further evaluation of alternative sites outside the boundaries of the MGS is not required.



## 5.5 ALTERNATIVE GENERATING CONFIGURATIONS AND TECHNOLOGIES

### 5.5.1 Proposed Configuration

The proposed configuration includes one General Electric (GE) 7HA.01 natural-gas-fired combustion turbine generator (CTG) operated in simple-cycle mode. The proposed layout has been optimized for plant-operating efficiencies, such as effective use of existing infrastructure and reuse of various facilities, including the ammonia tank and retention basins. The identified location for P3 is the most efficient location within the MGS boundaries that could support a facility of this configuration.

### 5.5.2 GE LMS-100s

Applicant initially considered use of a GE LMS-100s system. In its response to SCE's RFO for the Moorpark Sub-Area of the Big Creek/Ventura Local Reliability Area, Applicant submitted bids for three options: GE 7HA.01, GE LMS-100s, and conventional combined cycle. Based on the competitive bidding process, SCE selected the GE 7HA.01, and therefore the RAPA requires deployment of this technology. Deployment of alternative generating technology would fail to meet the project objective of meeting the obligations of the RAPA. Therefore, use of a GE LMS-100s system was eliminated from further consideration.

### 5.5.3 Conventional Combined-Cycle

Applicant initially considered use of a conventional combined-cycle system. As stated above, Applicant proposed a conventional combined-cycle plant as one of three options in response to SCE's RFO. Based on the competitive bidding process, SCE selected the GE 7HA.01, and therefore the RAPA requires deployment of this technology. Deployment of alternative generating technology would fail to meet the project objective of meeting the obligations of the RAPA. Therefore, use of a conventional combined-cycle plant was eliminated from further consideration.

## 5.6 WATER SUPPLY

P3 would be a dry-cooled facility and would use very little water (less than 20 acre-feet per year [AFY]). P3 will not include a steam cycle, and it will not use water for steam condensation purposes or as part of any process that uses water to reject power plant process heat or waste heat to the atmosphere. P3 will only use water for evaporative cooler makeup, service water, and water for combustion turbine washes. The proposed source of the process water for P3 is potable water provided by the City of Oxnard, the local water supply purveyor.

California Energy Commission (CEC) Staff and the Commission have found that a project deploying essentially the same technology as P3 was not using water for cooling purposes within the meaning of the CEC's policy on the use of fresh water for power plant cooling, as set forth in the CEC's 2003 Integrated Energy Policy Report, and the similar policy in State Water Quality Control Board (SWQCB) Resolution 75-58. (See Commission Decision, Marsh Landing Generating Station [MLGS], Docket 08-AFC-3, pp. 83-84, citing Staff Assessment, Exhibit 300, pp. 4.9-23 through 4.9-25 [CEC, 2010].) These policies specify that the use of fresh water for cooling purposes by power plants will be approved only when alternative water supply sources and alternative cooling technologies are shown to be environmentally undesirable or economically unsound. In the case of MLGS, Staff concluded, and the Commission concurred, that the proposed use of 50 AFY of fresh water supplied by the City of Antioch was consistent with these policies (CEC, 2010). In its Decision, the Commission found:

*“The MLGS will use water in CTG inlet air evaporative coolers and for service water and other industrial purposes. The inlet air evaporative coolers use a relatively small amount of water to reduce the temperature of the ambient air as it enters the combustion turbines to improve power*

*output and efficiency. In this process, water is introduced into the ambient air as it is drawn through the turbine. The MLGS will not use water for wet cooling or as part of a steam cycle or for steam condensation purposes. The MLGS also will not use any water for the purpose of rejecting waste heat produced by power plant processes to the atmosphere. Staff concluded that the MLGS will not use water for cooling purposes because it utilizes a project design that minimizes the use of water . . . We find that the Marsh Landing Project's use of either brackish groundwater or fresh water supplied by the City of Antioch for process uses will comply with Energy Commission water policy and SWQCB Resolution 75-58." (citations omitted)*

The technology to be deployed at P3, and the purposes for which water will be used, are essentially the same as in the case of the MLGS. The only material difference is that P3 will use considerably less water than even MLGS.

### 5.6.1 Recycled Water

As discussed above, the availability of recycled water (i.e., tertiary treated wastewater) at the MGS site was carefully evaluated in the 2011 Implementation Plan developed in connection with the OTC Policy. At that time, it was concluded that recycled water was not available at the MGS site. The circumstances surrounding the availability of recycled water have not changed materially since that time. The use of recycled municipal wastewater for process water needs at the P3 is still considered to be infeasible for the reasons provided below.

1. The City of Oxnard began construction of its Advanced Water Purification Facility (AWPF) in 2009. The plant currently is undergoing its final commissioning process. It is anticipated that the plant will begin operations in spring 2015. The Recycled Water Backbone System has been completed. This main pipeline will convey recycled water from the AWPF, north along Perkins, C Street, and Ventura Road to the River Ridge Golf Course, near the Santa Clara River. The first phase of the recycled water production capacity is 6.25 million gallons per day (MGD), or 7,000 AFY. Approximately, 1,500 AFY to 1,800 AFY of this will be delivered to the River Ridge Golf Club for irrigation. The remaining 5,200 to 5,500 AFY of recycled water will be delivered to an aquifer storage and recovery well that the City plans to construct in 2015, and to agricultural customers (Rydberg, 2014). The closest connection point from the P3 site to the City of Oxnard's Recycled Water Backbone System is more than 4 miles away (near Fifth Street and Ventura Road), and construction of a pipeline through already congested utility corridors to interconnect would be economically infeasible, considering the small amount of water used by P3.
2. The City of Ventura owns and operates the Ventura Water Reclamation Facility (VWRF), north of the Santa Clara River. Currently, the VWRF generates approximately 9 MGD of tertiary treated wastewater. This water is used for irrigation of golf courses, parks, and landscaping in the City of Ventura, and is discharged to the Santa Clara River Estuary (just north of the river where the river discharges to the ocean) under an order from the Los Angeles Regional Water Quality Control Board. Recently, in compliance with the renewal of the discharge permit, the City of Ventura has been conducting special studies for the Santa Clara River Estuary to assess continued discharge of the recycled water to the estuary or identify other potential customers, for uses such as urban and agricultural irrigation throughout the City of Ventura, and groundwater recharge and other uses outside the City of Ventura (Carollo and Stillwater Sciences, 2011; Carollo, 2014).

The VWRF is outside the boundaries of, and does not serve, the City of Oxnard. There is no connectivity between the City of Oxnard's water system and the VWRF distribution system. If the proposed project were to obtain recycled water from the VWRF, it would require installation of an approximately 2.5-mile-long pipeline along North Harbor Boulevard and across a large river (i.e., the Santa Clara River). Such an installation, assuming this water supply would be

available, would be considered economically infeasible given the small quantity of water needed by P3. An interconnection to an outside water purveyor may not even be administratively feasible.

3. The next closest facilities are 10 miles or more away from the site, and extensive infrastructure would be required to deliver recycled water, if even available, to the site. These facilities include:
  - The Ojai Valley Wastewater Treatment Plant is approximately 10 miles north of P3; it currently does not produce recycled water (Casitas Municipal Water District, 2011).
  - Camrosa Water Reclamation Facility is in the City of Camarillo, approximately 15 miles southeast of P3; it currently produces approximately 1.5 MGD of reclaimed water (Camrosa Water District, 2015)
  - Santa Paula Water Recycling Facility is approximately 12 miles northeast of P3; it currently produces approximately 3.4 MGD of recycled water (Santa Paula Water District, 2015).
  - The City of Fillmore Water Recycling Plan produces approximately 1.8 MGD of recycled water and is more than 20 miles away from P3 (American Water, 2015).
  - The Moorpark Wastewater Treatment Plan produces approximately 5 MGD of recycled water and is more than 20 miles away from P3 (PSOMAS, 2014).

There is no connectivity between the City of Oxnard's water system and any of these other water purveyors. Tertiary-treated recycled water is not feasibly available from these facilities due to jurisdictional, supply, and interconnection constraints. Accordingly, based on currently available information, recycled water supplies are not available.

P3 will deploy dry-cooling technology and use only a small quantity of potable water. Consistent with the MLGS Decision, the proposed use does not constitute use of fresh water for power plant cooling as governed by applicable CEC and SWQCB policies. There is an existing water supply line on the MGS property, and no new offsite infrastructure will be required to deliver water to the project. Use of recycled water would require construction of costly new pipelines, with resulting environmental impacts and disruptions due to construction in congested routes. Under these circumstances, even if P3's proposed water use fell within the scope of applicable policies, use of recycled water as an alternative water supply would be environmentally undesirable and economically unsound.

Furthermore, as discussed in Section 4.15, Water Resources, the quantity of potable water used for the proposed replacement project will be substantially less than what is currently used, which reduces the impact on the local water supply, and is a substantial benefit to the region.

### **5.6.2 Irrigation Return Flow**

Agriculture is a major industry in Ventura County and the City of Oxnard. In the vicinity of the project site, strawberries and row crops are the predominant crop types (Larry Walker Associates, 2013).

Discharges from irrigated agricultural lands in Ventura County, including irrigation return flows, flows from tile drains, and stormwater runoff, must comply with the Los Angeles Regional Water Quality Control Board's Conditional Waiver of Waste Discharge Requirements for Discharges from Irrigated Lands within the Los Angeles Region ("Conditional Waiver," Order No. R4-2010-0186).

These discharges can affect water quality by transporting nutrients, pesticides, sediment, salts, and other pollutants from cultivated fields into surface waters, potentially impairing designated beneficial uses of

receiving water bodies. The Ventura County Agricultural Irrigated Lands Group (VCAILG) is a group of landowners and growers that have joined together to comply with the Conditional Waiver as a “Discharger Group.”

The Oxnard Central Drain collects agricultural discharges from approximately 447 acres of farmland in northwestern Oxnard. A VCAILG monitoring site is located on the Oxnard Central Drain near Harbor Boulevard and Gonzales Road, approximately 1 mile north of the P3 site. The Oxnard Central Drain is monitored periodically during the year, usually one or two wet events and one or two dry events. For the 12 events monitored in 2007, 2009, 2010, and 2012, monitoring results indicate that flow in the drain has ranged from approximately 0.36 cubic foot per second (cfs) (dry period in July 2012) to 93.2 cfs (wet period in January 2010). Water quality exceeded benchmarks for nitrates, copper, and pesticides. Total dissolved solids exceeded 2,500 milligrams per liter for 9 of the 12 events (Larry Walker Associates, 2008, 2009, 2010, 2011, 2013).

Irrigation return flow is considered infeasible due to the cost of infrastructure that would be required to deliver the water to the project site, the unreliability of the flows, and the cost of treatment, if the water is even available. The use of irrigation return flow from the Oxnard Central Drain is considered impracticable for the following reasons:

- An extensive and costly infrastructure system would be required to deliver the water from the drain to the site. A pipeline would need to be constructed within the existing road rights-of-way along Harbor Boulevard, between the site and the drain (approximately 1 mile). A pump station would likely be required because of the generally flat terrain.
- The drain provides an unreliable source of water. The amount of water that is available depends on how the fields are operated, and how much irrigation water is applied and when; which in turn depends on the crop, climate, etc. Based on the data from VCAILG for recent monitoring, flow at the Oxnard Center Drain is highly variable throughout the year and from year to year. Because there are only periodic data available, it is uncertain if there is a sustained minimum flow at the drain.
- As a result of increased water conservation measures by growers, including more efficient irrigation practices and conversion to more water-efficient crops, irrigation return flows would be expected to become an increasingly unreliable source of water.
- The irrigation return flow may require treatment for use at the plant. The limited water quality data that are available for the Oxnard Central Drain indicate that the water would be expected to have elevated amounts of nitrates, pesticides, salts, and minerals.

### 5.6.3 Desalination

The existing MGS Units 1 and 2 currently use ocean water for once-through-cooling. The intake is located in the Edison Canal, and discharge is through the existing outfall structure. The proposed project could use ocean water as a supply for process water needs. The ocean water would require treatment at an onsite desalination facility. Desalination systems need to run continuously to be efficient and cost-effective. P3 is a peaking facility that will operate up to a 30 percent capacity factor. In addition, the very small amount of water needed by P3 does not justify the costs for constructing and operating an onsite desalination facility.

There are no regional desalination plants in the project region. The closest desalination plant to the project site is the Charles E. Meyer Desalination Facility in Santa Barbara, California, which is more than 40 miles away. This plant is currently mothballed and not in operation. It was constructed more than

20 years ago, but was never used. However, the City of Santa Barbara is currently evaluating water supply alternatives, including potentially starting this desalination plant.

Even if this plant were to begin operating, the distance makes connection to the project site economically infeasible.

#### **5.6.4 Onsite Groundwater**

Groundwater underlying the MGS property has been impacted by historical SCE (i.e., the former owner of MGS) operations. A Land Use Covenant will reportedly be put in place, restricting the use of groundwater pumped from the site. Therefore, this alternative water supply has not been considered for the proposed project.

### **5.7 WASTEWATER DISCHARGE**

P3 will discharge construction wastewater, process wastewater and stormwater to the existing MGS retention basins, and discharge via the existing outfall structure to the ocean in accordance with MGS' existing Waste Discharge Requirements (WDR) Order No. 01-057, National Pollutant Discharge Elimination System Permit Number CA0001180 (LARWQCB, 2001). Sanitary wastewater will be discharged to the existing MGS septic system in accordance with WDR Order No. R4-2008-0087 (LARWQCB, 2008). Reuse and repurposing of existing infrastructure minimizes the environmental impact footprint.

P3 will use inlet-air evaporative coolers and dry-cooling technology to reduce water consumption. P3 does not include a steam cycle and will not use water for steam condensation purposes. The project will use a reverse osmosis system to recycle process wastewater for reuse on site, further reducing process water demand. The project will incorporate water recycling from the evaporative cooling blowdown, and reuse this water in the cooling-water system.

The project evaluated the use of zero-liquid discharge (ZLD) technology. It was determined that the use of this technology for P3 is not viable for the following reasons: increased capital costs, increased annual operation costs, required transport and disposal of sludge to an offsite landfill, and consumption of energy, which reduces power plant output and efficiency. Considering the very small amount of water consumed by the proposed project (less than 20 AFY), the resulting small amount of wastewater (less than 10 AFY), and water quality and treatment considerations, the use of ZLD is not considered an economically viable alternative.

### **5.8 ELECTRIC TRANSMISSION LINES**

P3 would interconnect at the existing SCE switchyard, which is adjacent to the MGS site. Because the P3 transmission line would be very short and would connect directly into the SCE switchyard without the construction of offsite transmission lines, no alternative electric transmission routes were considered.

### **5.9 NATURAL GAS SUPPLY LINE**

Natural gas will be delivered to P3 by SoCalGas, which currently delivers natural gas to the MGS site. Natural gas will be provided using a new 10-inch-diameter line that will connect to a new gas metering station adjacent to the project site. The connection line will continue generally westward to a new gas compression enclosure on the P3 site. Because the gas pipeline interconnection is short and runs through existing power-generating facilities, no alternative gas pipeline routes were considered.

## 5.10 ALTERNATIVE AIR POLLUTION EMISSION CONTROL ANALYSIS

The project must comply with the requirements of the Ventura County Air Pollution Control District's (VCAPCD) permit regulations requiring the application of the Best Available Control Technology (BACT) to control air emissions. To comply with the VCAPCD's BACT requirements for oxides of nitrogen (NO<sub>x</sub>), the project's design includes dry low-NO<sub>x</sub> combustion controls on the gas turbines and selective catalytic reduction (SCR) to control NO<sub>x</sub> emissions. To comply with VCAPCD's BACT requirements for reactive organic compounds (ROCs), a carbon monoxide (CO) catalyst will be employed.

The SCR system for the CTG will operate with aqueous ammonia injected into the exhaust gas stream upstream of a catalyst bed to reduce NO<sub>x</sub> to inert nitrogen and water. The SCR technology proposed for P3 uses a 19 percent solution of ammonia to reduce NO<sub>x</sub> emissions to elemental nitrogen, water, and a small quantity of unreacted ammonia. Although the use and storage of ammonia would represent a potential risk to the public in the event of a catastrophic breach of the storage tank, the offsite consequence analysis (presented in Section 4.5, Hazardous Materials Management) shows that the potential impacts associated with the project's use and storage of ammonia would not result in a significant public health impact.

The remainder of this section presents alternative NO<sub>x</sub> emission control technologies considered for the project. The information presented below is based on the air quality analysis presented in Section 4.1, Air Quality.

Potential NO<sub>x</sub> control technologies for combustion gas turbines include the following:

- Combustion controls
  - Dry combustion controls
  - Dry low-NO<sub>x</sub> combustor design
  - Catalytic combustors (e.g., XONON™)
- Post-combustion controls
  - Selective non-catalytic reduction (SNCR)
  - Non-selective catalytic reduction (NSCR)
  - SCONO<sub>x</sub>™

The technical feasibility of available NO<sub>x</sub> control technologies is presented below.

### 5.10.1 Combustion Modifications

#### 5.10.1.1 Dry-Combustion Controls

Combustion modifications that lower NO<sub>x</sub> emissions without wet injection include lean combustion, reduced combustor residence time, lean pre-mixed combustion, and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor's primary combustion zone to cool the flame, thereby reducing the rate of thermal NO<sub>x</sub> formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NO<sub>x</sub> formation. Dry low-NO<sub>x</sub> combustion would be used on the GE 7HA.01 CTG for this project.

Catalytic combustors use a catalytic reactor bed mounted in the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name Xonon™ in a 1.5-MW natural-gas-fired combustion turbine in Santa Clara, California. No turbine vendor, other than

Kawasaki, has indicated the commercial availability of catalytic combustion systems at the present time, and the largest size is 18 MW. The technology is not commercially available for the proposed P3 turbine and other similarly sized combustion turbines; therefore, it is not considered further.

#### 5.10.1.2 Wet-Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NO<sub>x</sub> control techniques. These wet-injection techniques lower the peak flame temperature in the combustor, reducing the formation of thermal NO<sub>x</sub>. The injected water or steam exits the turbine as part of the exhaust. Although the lower peak flame temperature has a beneficial effect on NO<sub>x</sub> emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, emissions of CO and reactive organic gases increase as water/steam injection rates increase.

Water and steam injection have been in use on both oil- and gas-fired combustion turbines in all size ranges for many years, so these NO<sub>x</sub> control technologies are generally considered technologically feasible and widely available. Because dry low-NO<sub>x</sub> combustion controls are used in the GE 7HA.01 CTG and are more effective than water injection, water injection is not considered for this project.

#### 5.10.1.3 Post-Combustion Controls

Selective catalytic reduction is a post-combustion technique that controls both thermal and fuel-bound NO<sub>x</sub> emissions by reducing NO<sub>x</sub> with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NO<sub>x</sub> conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NO<sub>x</sub> combustion controls. SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO<sub>x</sub> control are in excess of 90 percent. SCR would be used on this project, in conjunction with the dry low-NO<sub>x</sub> combustion controls on the GE 7HA.01 CTG.

SNCR involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1,200 degrees Fahrenheit (°F) to 2,000°F, and is most commonly used in boilers. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for P3.

NSCR uses a catalyst without injected reagents to reduce NO<sub>x</sub> emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary internal combustion engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust, where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for P3.

The SCONO<sub>x</sub><sup>TM</sup> system, also known as EMX<sup>TM</sup>, is an add-on control device that reduces emissions of multiple pollutants. SCONO<sub>x</sub><sup>TM</sup> uses a single catalyst for the reduction of CO, volatile organic compounds (VOCs), and NO<sub>x</sub>, which are converted to carbon dioxide (CO<sub>2</sub>), water, and nitrogen.

The catalyst is a monolithic design, made from a ceramic substrate with both a proprietary platinum-based oxidation catalyst and a potassium carbonate adsorption coating. The catalyst simultaneously oxidizes nitric oxide to nitrogen dioxide, CO to CO<sub>2</sub>, and VOCs to CO<sub>2</sub> and water; while nitrogen dioxide is adsorbed onto the catalyst surface, where it is chemically converted to and stored as potassium nitrates and nitrites. The SCONO<sub>x</sub> potassium carbonate layer has a limited adsorption capability, and requires regeneration approximately every 12 to 15 minutes in normal service. Each regeneration cycle requires

approximately 3 to 5 minutes. At any point in time, approximately 20 percent of the compartments in a SCONO<sub>x</sub> system would be in regeneration mode, and the remaining 80 percent of the compartments would be in oxidation/absorption mode.

All installations of the technology have been on small, natural-gas facilities, and all of those facilities have experienced performance issues. The fact that SCONO<sub>x</sub><sup>TM</sup> has not been applied to large-scale natural-gas CTGs like the GE 7HA.01 creates concerns regarding the feasibility.

In a recent BACT analysis performed by SCAQMD for the Redondo Beach Energy Project, SCAQMD engineers did carry forward SCONO<sub>x</sub><sup>TM</sup> as a potential control for its turbines; however, the turbine proposed for this project is considerably larger (260 MW vs. 132 MW on the Redondo Beach Energy Project), and it remains true that SCONO<sub>x</sub><sup>TM</sup> has not been demonstrated in practice on a turbine similar to that proposed for P3. For the above reasons, SCONO<sub>x</sub><sup>TM</sup> is considered technically infeasible to meet the 2-parts per million NO<sub>x</sub> emission level that can be achieved with SCR.

### 5.10.2 Alternatives to Ammonia-Based Emission Control Systems

Over the last few years, several vendors have designed urea-based systems to generate ammonia on site, thereby eliminating the need to transport and store ammonia. These units are referred to as Ammonia on Demand and Urea-to-Ammonia (U2A) systems. The U2A system has limited commercial availability.

The U2A system generates ammonia from solid dry urea. The process starts by dissolving urea in deionized water to produce an aqueous urea solution. Steam is used in the U2A reactor to convert the urea solution into a gaseous mixture of ammonia, CO<sub>2</sub>, and water for use in the SCR system. The U2A technology has not been widely applied and accepted for use at simple-cycle or combined-cycle turbine facilities. Aqueous ammonia is currently used at the MGS site. Site personnel are trained and familiar with the safe handling and operation of the systems. Therefore, the U2A system is not considered for this project.

## 5.11 ALTERNATIVE TECHNOLOGIES

Although the SCE RFO included solicitation for renewable generation, the Applicant's offer was for a natural-gas-fired facility that would integrate with renewables. Therefore, the following alternative technologies were not considered because their use would not meet project objectives:

- Hydrogen-fired
- Biomass
- Solar
- Wind
- Oil
- Coal
- Nuclear
- Hydroelectric
- Geothermal
- Fuel cells

Alternative generating processes, such as solar or wind, generation plants, or use of "clean fuels," such as hydrogen or biomass, represent a completely different family of power generation plant designs from natural-gas peaking and combined cycle plants. Although hydrogen-fired or biomass-fired generation facilities may have certain similar components, such as cooling towers and turbine generators, the technical basis for these plants differs markedly from the natural-gas plant represented in the RAPA. In



addition, natural gas is a clean fuel, with its lower sulfur dioxide and particulate emissions than alternative fossil fuels; and in some cases, natural gas plants may be cleaner than combustion of hydrogen or biomass.

Use of solar or wind generation would not meet a couple of the primary objectives of the project, namely SCE's RAPA, and generation that would integrate renewable energy. Solar or wind generation therefore is not considered further as an alternative technology. Hydrogen-fired or biomass-fired generation would likewise not meet SCE's RAPA. Furthermore, space requirements, water use, and the cost of generation for these alternative technologies are relatively high compared to natural-gas-fired technologies, and may not allow for the same operating flexibility that the natural-gas-fired technologies provide.

Alternative fossil fuels such as oil and coal were not considered, due to the relatively lower efficiency and higher emissions of air pollutants per kilowatt-hour generated. Furthermore, the use of these fossil fuels is counter to California policy on use of lower carbon technologies.

California law prohibits new nuclear plants until the scientific and engineering feasibility of disposal of high-level radioactive waste has been demonstrated. To date, the CEC is unable to make the findings of disposal feasibility required by law for this technology to be viable in California. This technology, therefore, is not possible at this time.

Most of the sites for hydroelectric facilities have already been developed in California, and the remaining potential sites face lengthy environmental licensing periods. It is doubtful that this technology could be implemented within 3 to 5 years, and the cost would probably be higher than the cost of a conventional simple-cycle combustion turbine. There are no hydroelectric sites in the project area.

Geothermal development is not viable at the project location because suitable thermal resources and strata are not present. Therefore, geothermal was eliminated from consideration.

Fuel cells cleanly and efficiently convert chemical energy from hydrogen-rich fuels into electrical power and usable high quality heat in an electrochemical process, with minimal emission of pollutants. Fuel cell power plant applications come in building blocks of 1.4 MW. The largest stationary fuel cell power plant currently installed in the United States is 11.2 MW. To generate electricity, fuel cells require a continuous supply of fuel. The fuel can be any hydrogen-rich fuel, including natural gas or biogas. Fuel cells are not a viable option at this site for the following reasons: the technology has not been proven at the scale needed for the project; fuel cell plants are not engineered to be dispatchable or operate in a peaking manner; and fuel cells are significantly less efficient than the simple-cycle CTG technology proposed for P3. For all of these reasons, this technology would not be considered technologically or economically feasible for a 262-MW (nominal net) facility that needs to provide rapid-start and fast-ramping capability to allow for efficient integration of renewable energy sources.

## 5.12 REFERENCES

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