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ALAMITOS ENERGY CENTER

Final Staff Assessment, Part 2 for Alamitos Energy Center (AEC)

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CALIFORNIA
ENERGY COMMISSION
Edmund G. Brown, Jr., Governor

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ALAMITOS ENERGY CENTER (13-AFC-01)
FINAL STAFF ASSESSMENT – Part 2

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EXECUTIVE SUMMARY

Keith Winstead

INTRODUCTION

This Final Staff Assessment (FSA) of the Alamitos Energy Center, LLC's, Supplemental Application for Certification (13-AFC-01) contains staff's final, independent, objective evaluation and testimony for the proposed Alamitos Energy Center (AEC), a nominal 1,040-megawatt electrical generating facility. The FSA examines engineering, environmental, public health, and safety aspects of the proposed AEC project, based on the information provided by the applicant, government agencies, interested parties, independent research, and other sources available at the time the FSA was prepared. The FSA contains analyses and responses to comments similar to those normally contained in a Final Environmental Impact Report (FEIR) required by the California Environmental Quality Act (CEQA). When evaluating a proposed project and making a determination on issuing a license, the Energy Commission is the lead state agency under CEQA and its certified regulatory program functions as a CEQA equivalent process.

The Energy Commission staff has the responsibility to complete an independent assessment of the project's engineering design and identify the potential impacts on the environment, the public's health and safety, and determine whether the project conforms to all applicable laws, ordinances, regulations and standards (LORS). Upon identifying any potentially significant environmental impacts, staff recommends mitigation measures in the form of conditions of certification for construction, operation and eventual closure of the project.

This FSA is not a decision document for these proceedings, nor does it contain findings of the Energy Commission related to environmental impacts or the project's compliance with local, state, and federal LORS. The FSA serves as staff's formal testimony in evidentiary hearings to be held by the Energy Commission Committee assigned to hear this case. The Committee will hold evidentiary hearings and will consider the recommendations presented by the staff, the applicant, intervenors, government agencies, and the public, prior to proposing its decision. The full Energy Commission will make the final decision, including findings, after the Committee's publication of its proposed decision.

PROPOSED PROJECT LOCATION AND DESCRIPTION

On October 26, 2015, AES Southland Development, LLC (AES) submitted a Supplemental Application for Certification (SAFC) to the California Energy Commission for the AEC project. The SAFC replaces the original Application for Certification (AFC) filed on December 27, 2013.

The project description in the SAFC for the proposed AEC has changed from what was described in the AFC filed on December 27, 2013. The AEC would be a nominal 1,040-MW, natural-gas-fired, combined-cycle and simple-cycle, air-cooled electrical generating facility consisting of two power blocks to provide fast starting and stopping, reliable, and flexible multistage generating resources. Power Block 1 would consist of two natural-gas-fired combustion turbine generators (CTG) in a combined-cycle configuration (collectively AEC CCGT), with two unfired heat recovery steam generators (HRSG), one steam turbine generator (STG), an air-cooled condenser, an auxiliary boiler, and related ancillary equipment for a nominal 640 MW. Power Block 2 would consist of four natural gas-fired, simple-cycle CTGs with fin-fan coolers and ancillary facilities (collectively AEC SCGT) for a nominal 400 MW. The AEC is proposed to use potable water provided by the city of Long Beach Water Department (LBWD) for construction, operational process, and sanitary uses. This water would be supplied through existing onsite potable water lines.

The AEC would be constructed on the site of the Alamitos Generating Station (AGS), an existing and operating power plant located at 690 North Studebaker Road in the city of Long Beach, Los Angeles County, California. The AEC project would be located on an approximately 21-acre site within the larger 71-acre AGS site. The proposed project site is bounded to the north by Southern California Edison's (SCE) Alamitos switchyard and State Route 22 (East 7th Street); to the east by the San Gabriel River and, beyond that, the Los Angeles Department of Water and Power Haynes Generating Station; to the south by the former Plains West Coast Terminals petroleum storage facility and undeveloped property; and to the west by the Los Cerritos channel, AGS cooling-water canals, and the residences west of the channel. Land use in the region primarily includes urban development, industrial areas, undeveloped land, parklands, open space, and wetlands preserves. The AGS facility was built between 1955 and 1967. The facility included natural gas/oil, steam-turbine power generating units and was originally owned and operated by SCE. During the late 1990s, the electric industry was restructured, and SCE sold most of its generating facilities. In 1998, AES Southland purchased AGS from SCE.

The project site comprises Assessor's Parcel Numbers (APN) 7237-017-805, 7237-017-806, 7237-017-807, 7237-017-808, 7237-017-809, 7237-018-807, 7237-018-808, 7237-019-005 and 7237-019-808, and the construction lay down area consists of 10-acres of an adjacent parcel to the south (APN 7237-019-006).

The AEC would interconnect to the existing SCE 230-kilovolt (kV) switchyard adjacent to the northern side of the property. No new offsite natural gas lines would be necessary for the project. AEC would be supplied via the existing service pipeline for AGS Units 5 and 6 from the offsite 30-inch-diameter, high-pressure pipeline owned and operated by Southern California Gas Company (SoCalGas). Natural gas compressors, water treatment facilities, emergency services, and administration and maintenance buildings would be constructed within the existing site footprint. Storm water would be discharged into two retention basins and then ultimately to the San Gabriel River via existing storm water outfalls.

As described in the SAFC, the AEC CCGT would be located on the southern-most portion of the AEC site, on the former AGS fuel oil-storage site. AEC CCGT would include the following principal design elements:

- Two General Electric (GE) 7FA.05 CTGs with a nominal rating of 227 MW each. The CTGs would be equipped with evaporative coolers on the inlet air system and dry low oxides of nitrogen (NOx) combustors;
- Two HRSGs with no supplemental firing, each equipped with a selective catalytic reduction (SCR) unit in the ductwork for the control of NOx emissions, and an oxidation catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions;
- One, single-flow, impulse, down-exhaust-condensing STG with a nominal rating of approximately 229 MW;
- One air-cooled condenser;
- A new natural gas compressor and compressor building for the CCGT;
- One generator step-up (GSU) transformer per each GE 7FA combustion turbine generator and one for the steam turbine generator; and
- One 230-kV interconnection to the existing SCE switchyard, which is adjacent to the site.

The AEC SCGT would be located on the northern portion of the AEC site, adjacent to the San Gabriel River. The AEC SCGT would include the following principal design elements:

- Four GE Energy LMS 100 PB natural gas-fired CTGs with a nominal rating of 100 MW each;
- Each CTG would be equipped with SCR equipment containing catalysts to further reduce NOx emissions, and an oxidation catalyst to reduce CO emissions;
- Auxiliary equipment associated with each CTG would include an inlet-air-filter house with evaporative cooler, turbine intercooler and associated intercooler circulating pumps;
- Each pair of CTGs would share one fin-fan heat exchanger and one GSU transformer;
- A new natural gas compressor and compressor building for the SCGT; and
- One 230-kV interconnection to the existing onsite SCE 230-kV switchyard.

The two power blocks would share the following design elements:

- Direct connection to an existing SoCalGas 30-inch-diameter, natural gas pipeline and metering station;
- Connection to existing onsite municipal and industrial water lines;
- Fire water and suppression systems;

- A new 1,000-linear-foot process/sanitary wastewater pipeline to the first point of interconnection with the existing LBWD sewer system at the east end of East Vista Street in Long Beach;
- An existing storm water retention pond; and
- Water treatment and storage systems.

OFFSITE INFRASTRUCTURE IMPROVEMENTS

The AEC would include a new 1,000 linear-foot process/sanitary wastewater pipeline to the first point of interconnection with the existing LBWD sewer system and would eliminate the current practice of treatment and discharge of process/sanitary wastewater to the San Gabriel River. The upgrading of approximately 4,000 linear feet of the existing offsite LBWD sewer line downstream of the first point of interconnection discussed in the SAFC is no longer necessary and has been removed from the project design.

PROJECT OBJECTIVES

The applicant’s SAFC identifies the project’s primary objective to design a project that provides local area capacity at the existing AGS site. In addition to the primary objective, these are the basic project objectives:

- Develop a project capable of providing energy, generating capacity, and ancillary electrical services (voltage support, spinning reserve, and inertia) to satisfy Los Angeles Basin Local Reliability Area requirements and transmission grid support, particularly in the western subarea of the Los Angeles Basin.
- Provide fast starting and stopping, flexible, controllable, generation with the ability to ramp up and down through a wide range of electrical output to allow the efficient integration of renewable energy sources into the electrical grid, and replace older, once-through cooled and less efficient generation.
- Develop on a brownfield power plant site and use existing infrastructure, including the existing switchyard and related transmission facilities, the SoCalGas natural gas pipeline system, the LBWD water connections, process water supply lines, and existing fire suppression and emergency service facilities.
- Use qualifying technology under the South Coast Air Quality Management District’s Rule 1304(a)(2) exemption that allows for the replacement of older, less-efficient electric utility steam boilers with specific new generation technologies on a megawatt-to-megawatt basis (that is, the replacement megawatts are equal or less than the megawatts from the electric utility steam boilers).

Staff’s alternatives analysis broadly interprets the applicant’s project objectives to foster a complete and robust discussion of potential alternatives to the applicant’s proposed project.

PROJECT ALTERNATIVES

As required by CEQA, staff evaluated a reasonable range of alternatives to the proposed project that would feasibly attain most of the basic objectives of the project and would avoid or substantially lessen any of the significant effects of the project. As a starting point, staff reviewed the alternatives analysis provided by the applicant in the SAFC. The applicant found that the alternatives considered in the SAFC were either infeasible, unable to reduce or avoid any adverse environmental impacts, or would not attain most of the basic objectives of the project; staff concurs with the applicant's assessment of their alternatives. The alternatives considered by staff in the FSA include one off-site alternative and the no-project alternative. The No-Project Alternative presented in staff's analysis evaluated a no-build scenario at the project site. Subsequently, the off-site alternative was eliminated from further consideration as infeasible, while the no-project alternative was carried forward for further evaluation. Staff also considered "preferred resources" (energy efficiency, demand response, utility-scale and distributed renewable generation, and storage) as alternatives to dispatchable natural gas-fired generation such as the proposed AEC. Staff has not identified a feasible alternative that would be environmentally superior to the proposed AEC.

PUBLIC AND AGENCY COORDINATION

On January 15, 2014, the Energy Commission staff issued a notification of receipt of the Application for Certification, together with a project description, to property owners within 1,000 feet of the proposed project and those located within 500 feet of the linear facilities (such as transmission lines, gas lines and water lines). See California Code of Regulations Title 20 section 1709.7(a)). These notices informed the public and agencies of the Commission's receipt and availability of the Supplemental AFC, discussed the Energy Commission's siting certification process, provided information on how the public can comment and participate in the proceeding, as well as provided a brief description of the project, and a link to a Commission-maintained project website http://www.energy.ca.gov/sitingcases/alamitos/index.html

LIBRARIES

On January 15, 2014, the Energy Commission staff also sent copies of the Alamitos Energy Center AFC to the following libraries:

Long Beach Main Library
101 Pacific Avenue
Long Beach, CA 90822

Long Beach Public Library – Los Altos Neighborhood
5614 E Britton Drive Long Beach, CA 95801

Bay Shore Neighborhood Library
195 Bay Shore Avenue
Long Beach, CA 90803

Los Alamitos-Rossmoor Library
12700 Montecito Road
Seal Beach, CA 90740

Brewitt Neighborhood Library
4036 E. Anaheim
Long Beach, CA 90804

In addition to these local libraries, copies of the AFC were also made available at the Energy Commission's Library in Sacramento, the California State Library in Sacramento, as well as state libraries in Eureka, Fresno, Los Angeles, San Diego, and San Francisco.

ENERGY COMMISSION'S PUBLIC ADVISER'S OFFICE

The Energy Commission's outreach program is also facilitated by the Public Adviser's Office (PAO). The PAO engages in continuous public outreach that has included placing a notice in the April 19, 2014 issue of the Long Beach Press-Telegram and Impacto USA newspapers announcing the Informational Hearing and Site Visit for this project that was held on April 29, 2014. The PAO also issued public notices informing the public of the availability of the project website where the public can obtain more information. The PAO requested public service announcements at a variety of organizations and distributed notices informing the public of the Commission's receipt of the AEC AFC.

CONSULTATION WITH LOCAL NATIVE AMERICAN COMMUNITIES

Energy Commission staff sent written correspondence to the Native American Heritage Commission, as well as to a number of Native American tribes who have expressed an interest in being contacted about development projects in the AEC area. This correspondence served as an invitation for tribes to consult on the project. Please see the **Cultural Resources** section of this staff assessment for details of staff's consultation with Native American tribes to date.

SUMMARY OF PROJECT IMPACTS, MITIGATION, AND LORS COMPLIANCE

Staff concludes that with implementation of staff's recommended mitigation measures described in the conditions of certification, the AEC would comply with all applicable laws, ordinances, regulations, and standards (LORS). Staff also concludes that for all areas, significant adverse direct, indirect, and cumulative impacts would not occur. In the technical area of Air Quality, additional information is needed to demonstrate that all applicable LORS would be met, and all impacts would be mitigated to less than significant.

The conclusions reached in each technical area (chapter) are summarized in the table and discussed below. For a detailed review of potentially significant impacts, related mitigation measures, and LORS compliance, please refer to each chapter of the FSA.

Executive Summary - Table 1
Summary of Environmental and Engineering Assessment

Technical Area	Complies with LORS	Impacts Mitigated	Additional Information Required
Air Quality/Greenhouse gases	Yes	Yes	No
Biological Resources	Yes	Yes	No
Cultural Resources	Yes	Yes	No
Facility Design	Yes	Yes	No
Geology and Paleontology	Yes	Yes	No
Hazardous Materials Management	Yes	Yes	No
Land Use	Yes	Yes	No
Noise and Vibration	Yes	Yes	No
Power Plant Efficiency	Yes	Yes	No
Power Plant Reliability	N/A	N/A	No
Public Health	Yes	Yes	No
Socioeconomics	Yes	Yes	No
Soil and Water Resources	Yes	Yes	No
Traffic and Transportation	Yes	Yes	No
Transmission Line Safety and Nuisance	Yes	Yes	No
Transmission System Engineering	Yes	N/A	No
Visual Resources	Yes	Yes	No
Waste Management	Yes	Yes	No
Worker Safety and Fire Protection	Yes	Yes	No

AIR QUALITY/GREENHOUSE GASES

Staff concludes that with the adoption of the proposed conditions of certification, AEC would not result in significant air quality related impacts during project construction or operation, and the project would comply with all applicable federal, state, and South Coast Air Quality Management District (SCAQMD) air quality LORS. Mitigation for operations would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits, registered Emission Reduction Credits, and offsets secured from SCAQMD internal accounts to fully mitigate the project's emissions of all nonattainment pollutants and their precursors. These mitigation measures are expected to reduce potential operational impacts of the proposed project to less than significant. The SCAQMD published a Final Determination of Compliance (FDOC) identifying all sources of the proposed mitigation for AEC. The FDOC concluded that AEC would comply with applicable LORS.

AEC would emit over 25,000 metric tonnes of carbon dioxide equivalent emissions and therefore would be subject to, and expected to comply with, mandatory state and federal greenhouse gas reporting and state cap-and-trade requirements. The applicant expects to operate the proposed combustion turbines below an annualized plant capacity factor of 60 percent. Therefore the proposed AEC would not be considered a base load facility and the combustion turbines would not be subject to California's Greenhouse Gases Emission Performance Standard.

PUBLIC HEALTH

Staff has conducted a health risk assessment for the proposed AEC and found no potentially significant adverse impacts for any receptors, including sensitive receptors. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the California Environmental Protection Agency Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff's assessment is protective of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff's analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions of this project, including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions, would not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

Staff incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that there would be no direct or cumulative significant public health impact on any population in the area. Therefore staff concludes that construction and operation of the AEC would comply with all applicable LORS regarding long-term and short-term project impacts in the area of public health.

Discussions regarding impacts and proposed mitigation for the other technical areas analyzed for the AEC AFC along with the Master List of Cumulative Projects considered in conjunction with the project, are in the AEC FSA Part 1, published September 23, 2016 (TN#213768).

REFERENCES

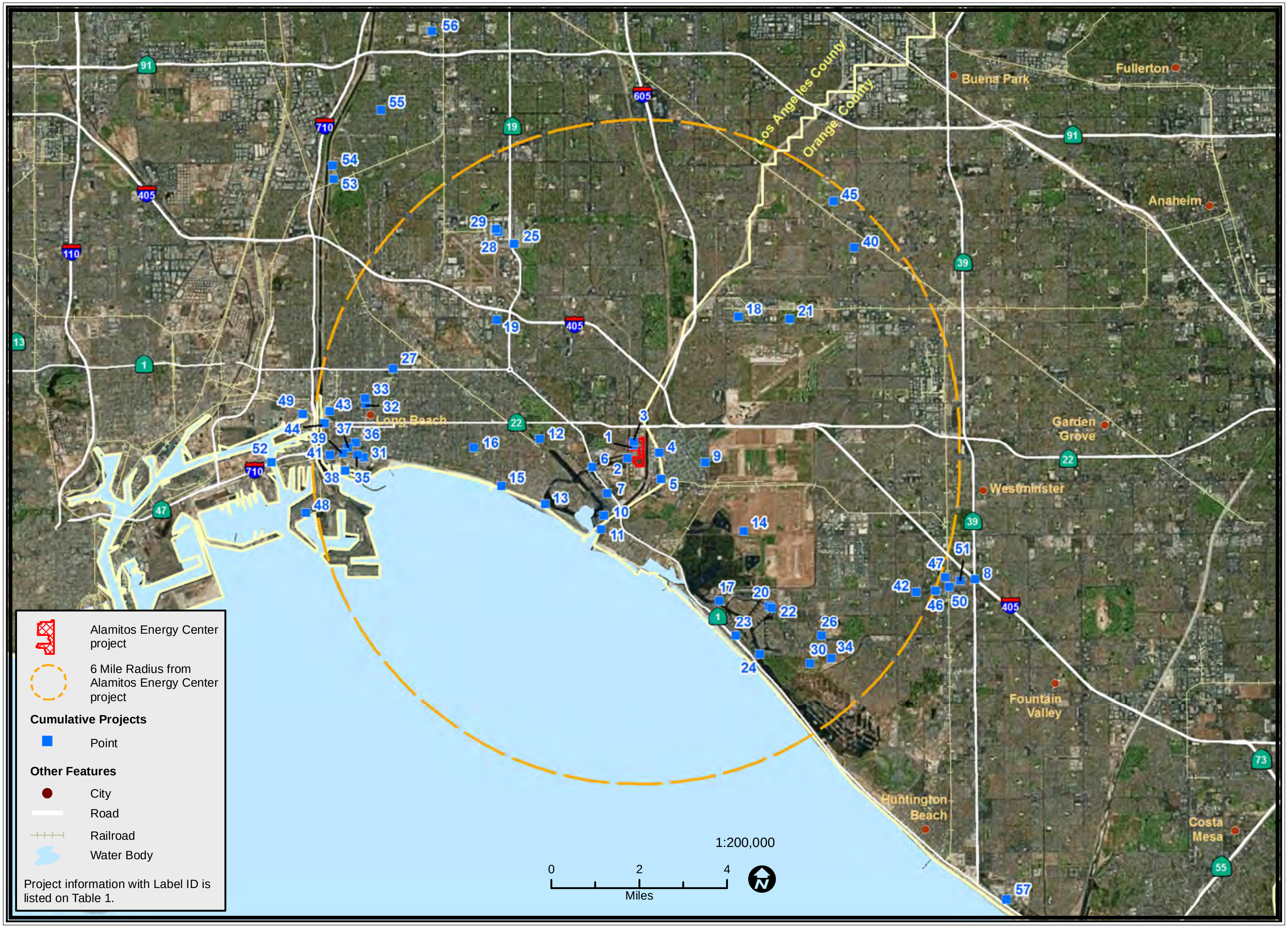
AEC 2015f – Alamitos Energy Center Supplemental AFC (TN 206427-1). Submitted on October 26, 2015. CEC/Docket on October 26, 2015.CH2 2016y – CH2MHill (TN 212487). Preliminary Staff Assessment Initial Comments, dated July 27, 2016. Submitted to CEC/Dockets on July 27, 2016

CEQ 1997 – Council on Environmental Quality. Environmental Justice: Guidance Under the National Environmental Policy Act. December 10, 1997, http://www.epa.gov/compliance/ej/resources/policy/ej_guidance_nepa_ceq1297.pdf .

US EPA 1998 – United States Environmental Protection Agency, Final Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. April 1998. http://www.epa.gov/compliance/ej/resources/policy/ej_guidance_nepa_epa0498.pdf

EXECUTIVE SUMMARY - FIGURE 1

Alamitos Energy Center - Cumulative Projects



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: OpenStreetMap January 2014, ESRI, Bing Aerial Image

INTRODUCTION

Keith Winstead

PURPOSE OF THIS REPORT

The Final Staff Assessment (FSA) is the California Energy Commission (Energy Commission) staff's independent analysis of the proposed Alamitos Energy Center (AEC). This FSA is a staff document. It is not a Committee document, nor a draft decision. The FSA describes the following:

- the proposed project;
- the existing environment;
- staff's analysis of whether the facilities can be constructed and operated safely and reliably in accordance with applicable laws, ordinances, regulations, and standards (LORS);
- the environmental consequences of the project including potential public health and safety impacts;
- the potential impacts of the project in conjunction with other existing and known planned developments;
- mitigation measures proposed by the applicant, interested agencies, intervenor, city of Long Beach and staff, which may lessen or eliminate potential impacts;
- staff's proposed conditions of certification (conditions) under which the project should be constructed and operated, if it is certified; and
- project alternatives.

Information for the analysis contained in this FSA comes from the following:

- the Application for Certification (AFC) and Supplemental AFC;
- responses to data requests;
- information from the local, state, federal agencies, interested organizations, and individuals;
- existing documents and publications;
- independent research; and
- comments made at public workshops or submitted in writing.

The FSA presents conclusions about potential environmental impacts and conformity with LORS, as well as proposed mitigation in the form of conditions of certification (COCs) that apply to the design, construction, operation and closure of the facility. The analyses for most technical areas include discussions of proposed COCs. The COCs contain staff's recommended measures to mitigate the project's environmental impacts and to ensure conformance with LORS. Each proposed COC is followed by a proposed means of "verification" to ensure the COCs are implemented. The Energy Commission analysis was prepared in accordance with Public Resources Code section 25500 et seq., Title 20, California Code of Regulations section 1701 et seq., and the California Environmental Quality Act (CEQA) (Pub. Resources Code § 21000 et seq.).

ORGANIZATION OF THE FSA

The FSA contains the Executive Summary, this Introduction, and a Project Description. The report then discusses Air Quality and Public Health and concludes with a list of staff that assisted in preparing this report, including their declarations and resumes.

Each section of the environmental and engineering assessment includes:

- applicable laws, ordinances, regulations and standards (LORS);
- the regional and site-specific setting;
- project specific and cumulative impacts;
- mitigation measures;
- closure requirements;
- Response to comments received on the PSA
- conclusions and recommendations; and
- conditions of certification for both construction and operation, if applicable.

ENERGY COMMISSION SITING PROCESS

The Energy Commission has the exclusive authority to certify the construction, modification, and operation of thermal electric power plants 50 megawatts (MW) or larger. The Energy Commission certification is in lieu of any permit required by state, regional, or local agencies, and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). The Energy Commission must review thermal power plant applications for certification (AFC) to assess potential environmental impacts including potential impacts to public health and safety, potential measures to mitigate those impacts, and compliance with applicable governmental laws or standards (Pub. Resources Code, § 25519 and § 25523(d)).

The Energy Commission's siting regulations require staff to independently review the AFC, assess whether all of the potential environmental impacts have been properly identified, and whether additional mitigation or other more effective mitigation measures are necessary, feasible, and available (Cal. Code Regs., tit. 20, § 1742). In addition, staff must assess the completeness and adequacy of the measures proposed by the applicant to ensure compliance with health and safety standards and the reliability of power plant operations (Cal. Code Regs., tit. 20, § 1742). Staff is required to develop a compliance plan (coordinated with other agencies) to ensure that applicable laws, ordinances, regulations, and standards are met (Cal. Code Regs., tit. 20, § 1744(b)).

Staff conducts its environmental analysis in accordance with the requirements of CEQA. No additional Environmental Impact Report (EIR) is required because the Energy Commission's site certification program has been certified by the Secretary of the California Natural Resources Agency as meeting all requirements of a certified regulatory program (Pub. Resources Code, § 21080.5 and Cal. Code Regs., tit. 14, § 15251 (j). The Energy Commission is the CEQA lead agency.

Staff prepares both a Preliminary Staff Assessment (PSA) and FSA. The PSA was published on July 13, 2016 and contains staff's preliminary analysis, conclusions, and recommendations. Staff provided a 30-day public comment period that follows the publication of the PSA. The comment period is also used to resolve issues between the parties and to narrow the scope of adjudicated issues in the evidentiary hearings. During this time, staff conducted one workshop in Long Beach to discuss its conclusions, proposed mitigation, and proposed verification measures. Based on the workshop dialogue and written comments received, staff refined its analysis, corrected errors, and finalized conditions of certification to reflect any changes agreed to between the parties. These revisions and changes are presented in the FSA which is published and made available to the public and all interested parties. The FSA serves as staff's primary testimony for evidentiary hearings.

The FSA is only one piece of evidence that will be considered by the Committee (two Energy Commission Commissioners who have been assigned to this project) in reaching a decision on whether or not to recommend that the full Energy Commission approve the proposed project. At the public evidentiary hearings, all parties will be afforded an opportunity to present evidence and to rebut the testimony of other parties, thereby creating a hearing record on which a decision on the project can be based. The hearing before the Committee also allows all parties to argue their positions on disputed matters, if any, and it provides a forum for the Committee to receive comments from the public and other governmental agencies.

Following the hearings, the Committee's recommendation to the full Energy Commission on whether or not to approve the proposed project, and the mitigation to be imposed, will be contained in a document entitled the Presiding Member's Proposed Decision (PMPD). Following publication, the PMPD is circulated for 30 days in order to receive written public comments. At the conclusion of the comment period, the Committee may prepare a revised PMPD if necessary. At the close of the comment period for the revised PMPD, the PMPD is submitted to the full Energy Commission for a decision on the project.

AGENCY COORDINATION

As noted above, the Energy Commission certification is in lieu of any permit required by state, regional, or local agencies and federal agencies to the extent permitted by federal law (Pub. Resources Code, § 25500). However, staff is required to provide notice of the proposed project to relevant agencies that administer LORS that are applicable to proposed projects or have other related expertise. Staff coordinates with these agencies in developing the staff assessment. The agencies associated with the AEC include the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, U.S. Army Corps of Engineers, California Coastal Commission, State Water Resources Control Board/Regional Water Quality Control Board, California Department of Fish and Wildlife, Caltrans, the California Air Resources Board, the South Coast Air Quality Management District, the city of Long Beach, and the Long Beach Fire and Police Departments.

OUTREACH

The Energy Commission's outreach program is primarily facilitated by the Public Adviser's Office (PAO). This is an ongoing process that provides a consistent level of public outreach, regardless of outreach efforts conducted by the applicant or other parties.

LIBRARIES

On January 15, 2014, Energy Commission staff sent the AEC AFC to the Long Beach Main Library; the Los Altos, Brewitt, and Bay Shore branches of the Long Beach Public Library; and the Los Alamitos-Rossmoor Library in Seal Beach. Copies were also provided to state libraries in Eureka, Sacramento, Fresno, San Francisco, Los Angeles and San Diego. On December 14, 2015, the Supplement to the AFC was also sent to the libraries.

INITIAL OUTREACH EFFORTS

The Public Adviser's Office (PAO) reviewed related information available from the applicant and others and then conducted its own, extensive outreach efforts to identify certain local officials, as well as interested entities, within a five-mile radius around the proposed site for the AEC. These entities include schools, as well as business, environmental, governmental, and ethnic organizations. By means of e-mail, the PAO notified these entities of the Informational Hearing and Site Visit for the project, held on April 29, 2014, at Grand Ballroom Recreation Park 18-hole Golf Course in Long Beach.

The PAO also identified and similarly notified local officials with jurisdiction in the project area. Notices directed the public to the website for more information. In addition, the PAO placed notices in the April 19, 2014 issues of the Long Beach Press-Telegram and Impacto USA newspapers announcing the Informational Hearing and Site Visit for this project.

Energy Commission regulations require staff to notice, at a minimum, property owners within 1,000 feet of a project and 500 feet of a linear facility (such as transmission lines, gas lines, and water lines). This was done for the project. Staff's ongoing public and agency coordination activities for this project are discussed under the Public and Agency Coordination heading in the **Executive Summary** section of the FSA.

Environmental Assessment

AIR QUALITY

Testimony of Nancy Fletcher

SUMMARY OF CONCLUSIONS

Staff concludes that with the adoption of the attached conditions of certification, the proposed Alamitos Energy Center (AEC or project) would not result in significant air quality related impacts during project construction or operation, and that the AEC would comply with all applicable federal, state, and South Coast Air Quality Management District (SCAQMD or District) laws, ordinances, regulations and standards (LORS) and California Environmental Quality Act (CEQA) requirements.

The project would be constructed on a site adjacent to the existing Alamitos Generating Station (AGS) power plant. AGS consists of six operating generating units (Units 1-6), and one retired generating unit (Unit 7). The AEC project owner will be utilizing SCAQMD's Rule 1304 program, which would require the retirement of a portion of the boilers operating at the AGS facility.

The SCAQMD published a Preliminary Determination of Compliance (PDOC) and proposed revised Title V permit on June 30, 2016. Written comments were received from the SCAQMD, the applicant, AES Alamitos Energy LLC (AES), and the public. A Final Determination of Compliance (FDOC) was published on November 18, 2016. The FDOC identified all the sources of the proposed mitigation for the AEC. The SCAQMD incorporated appropriate changes in the FDOC based on comments received on the PDOC. The FDOC includes an addendum detailing the comments received and provides responses to those comments. Per the FDOC, the SCAQMD determined the AEC would comply with applicable LORS.

The PDOC and the proposed revised Title V permit are being re-noticed by the SCAQMD concurrently with the FDOC review. There are no changes to the PDOC or any other document being re-noticed. Any comments received would be addressed prior to the issuance of the Permits to Construct. In addition, depending on the timing and scope of any changes made by the SCAQMD, the Energy Commission may need to take some action to address the changes. The project owner provided proof of noticing demonstrating that all required noticing was performed as required by Health and Safety Code §42301.6 and SCAQMD Rule 212(c)(1) and 212(c)(2).

Staff concludes that mitigation for operations would be provided in the form of Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs), registered Emissions Reduction Credits (ERCs), and offsets secured from SCAQMD internal accounts to fully mitigate emissions of all nonattainment pollutants and their precursors. These mitigation measures are expected to reduce potential operational impacts of the proposed project to less than significant.

Staff has assessed the potential for localized impacts and regional impacts for the project's proposed construction, commissioning, and operation. Staff is recommending mitigation and monitoring requirements sufficient to reduce potential adverse construction, commissioning, and operating emission impacts to less than significant.

Staff has considered the potential for adverse air quality impacts to the minority populations surrounding the site. The adoption of the recommended conditions of certification is expected to reduce the project's direct and cumulative air quality impacts to less than significant. The cumulative analysis was updated to reflect the revised cumulative modeling performed by the applicant and submitted to the docket on August 22, 2016 (CH2 2016ee). Per the updated analysis, the project is not expected to result in a significant or adverse impact to any identified environmental justice population.

Global climate change and greenhouse gas (GHG) emissions from the proposed project are discussed and analyzed in **Air Quality Appendix AIR-1**. The project owner expects to operate the proposed gas turbines below an annualized plant capacity factor of 60 percent. Therefore the proposed plant would not be considered a base load facility and the turbines would not be subject to the Greenhouse Gases Emission Performance Standard

The California Air Resources Board (ARB) adopted regulations implementing cap-and-trade regulations on December 22, 2011. The cap-and-trade program became active in January 2012, with enforcement beginning in January 2013. ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs. The proposed facility modifications are expected to be subject to federal and state mandatory GHG reporting and state cap-and-trade requirements. The project would emit over 25,000 metric tonnes of carbon dioxide equivalent ($MTCO_2e$) emissions and therefore would be subject to mandatory state and federal GHG reporting requirements.

INTRODUCTION

On December 27, 2014, AES Southland Development, LLC (AES-SD) submitted an Application for Certification (AFC) to the Energy Commission to construct and operate a combined-cycle generating facility. Due to changes in the project design, AES submitted a Supplemental Application for Certification (SAFC) for a combined-cycle Power Block 1 and simple-cycle Power Block 2 electrical generating facility on October 26th 2015. The project would be constructed on a site adjacent to the existing AGS power plant. AGS consists of Units 1-6, Unit 7, four aqueous ammonia tanks, and other associated equipment. AGS Units 1-6 are natural gas-fired boilers equipped with selective catalytic reduction (SCR) technology for emission control. Units 1-6 were installed by Southern California Edison (SCE) in 1956, 1957, 1961, 1962, 1969 and 1966 respectively. AGS was purchased from SCE by the AES Corporation in 1998. AGS is an electric generator currently in operation; however, it is not licensed through the Energy Commission. AGS is permitted by the SCAQMD and totals 1,950 megawatts (MW) for the six units.

AGS is a Title V, Acid Rain, and RECLAIM facility. AGS Units 1-6 would be in operation through the construction of the AEC. AGS is currently in compliance with all federal, state and local rules and regulations. This analysis evaluates the expected air quality impacts of criteria air pollutant emissions from the demolition, construction and operation associated with the proposed AEC. Criteria air pollutants are defined as air contaminants for which the state and/or federal government has established an ambient air quality standard to protect public health. The criteria pollutants analyzed are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), inhalable particulate matter (PM10), and fine particulate matter (PM2.5). In addition, nitrogen oxides (NOx), consisting primarily of nitric oxide (NO) and NO_2, sulfur oxides (SOx) and volatile organic compounds (VOC) are also analyzed. NOx and VOC react in the atmosphere as precursors to ozone. NOx and SOx emissions react in the atmosphere to form particulate matter, and are contributors to acid rain. GHG emissions from the project are discussed and analyzed in the context of cumulative impacts (**Air Quality Appendix AIR-1**).

In carrying out this analysis, the California Energy Commission (Energy Commission) staff evaluated the following major points:

- Whether the AEC is likely to conform with applicable federal, state, and SCAQMD air quality laws, ordinances, regulations and standards (Title 20, California Code of Regulations, section 1742 (d));
- Whether the AEC is likely to cause significant air quality impacts, including new violations of ambient air quality standards, or make substantial contributions to existing violations of those standards (Title 20, California Code of Regulations, section 1744.5); and
- Whether the mitigation measures proposed for AEC are adequate to lessen the potential impacts to a level of insignificance (Title 20, California Code of Regulations, section 1742 (b)).

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

The following federal, state, and local LORS and policies pertain to the control of criteria pollutant emissions and the mitigation of air quality impacts. Staff's analysis describes or evaluates the proposed facility's compliance with these requirements, shown in **Air Quality Table 1**. Additional analysis of AEC's compliance with these LORS, including discussion of how the facility meets the LORs requirements outlined in **Air Quality Table 1,** is included in the **Compliance with LORS** section.

Air Quality Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	**United States Environmental Protection Agency**
Title 40 Code of Federal Regulations (CFR) Part 50 (National Primary and Secondary Ambient Air Quality Standards)	National Ambient Air Quality Standards (NAAQS) are set in this part. NAAQS define levels of air quality that are necessary to protect public health.

Applicable LORS	Description
Title 40 CFR Part 51 (Requirements for Preparation Adoption and Submittal of Implementation Plans)	Requires new source review (NSR) facility permitting for construction or modification of specified stationary sources. NSR applies to sources of designated nonattainment pollutants. This requirement is addressed through SCAQMD Regulation XIII.
Title 40 CFR Part 52 (Approval and Promulgation of Implementation Plans)	Prevention of Significant Deterioration (PSD)–Establishes requirements for attainment emissions. PSD requirements apply on a pollutant specific basis for major stationary sources. Twenty-eight source categories are subject to PSD requirements for attainment pollutants if facility annual emissions exceed 100 tons per year. SCAQMD has partial delegation of PSD authority from the United States Environmental Protection Agency (U.S. EPA) depending on the calculation methodology and plant wide applicability limits.
Title 40 CFR Part 60, Subpart A (General Provisions)	Outlines general requirements for facilities subject to standards of performance including, notification, work practice, monitoring and testing requirements.
Title 40 CFR Part 60, Subpart Dc (Standards of Performance for Small Industrial Commercial Institutional Steam generating Units)	Establishes new source performance standards (NSPS) for steam generating units with heat input rates between 10 and 100 million British thermal units (MMBtu) per hour (hr). The auxiliary boiler would be subject to the requirements and fuel records would need to be retained.
Title 40 CFR Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines)	Establishes NSPS for new combustion turbines and the associated heat recovery steam generator (HRSG) and duct burners. NOx emissions are limited to 15 parts per million (ppm) at 15 percent oxygen (O_2) and fuel sulfur limit of 0.060 pounds (lbs) of SOx per MMBtu heat input.
Title 40 CFR Part 60, Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for electrical Generating Units)	Establishes standards of performance for carbon dioxide (CO_2). Affected base load electric generating units are subject to a gross energy output standard of 1,000 lbs of CO_2 per megawatt hour (MWh).
Title 40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)	Establishes National Emission Standards for Hazardous Air Pollutants (NESHAPS). The proposed AEC would not exceed the major source thresholds for hazardous air pollutants (HAPs) (10 tons per year for any one pollutant or 25 tons per year for HAPs combined). In additional this project does not include any stationary reciprocating internal combustion engines (ICEs).
Title 40 CFR Part 64 (Compliance Assurance Monitoring)	Compliance Assurance Monitoring (CAM) establishes operation and maintenance requirements for emission control systems. The proposed emission control system would require continuous emission monitoring under a Title V permits and is therefore exempt from these requirements.
Title 40 CFR Part 68 (Chemical Accident Prevention Provisions)	The proposed project would be exempt from this requirement. The proposed project would be subject to California's Accidental Release Prevention Program for aqueous ammonia storage and use.
Title 40 CFR Part 70 (State Operating Permit Programs) 42 USC 7661-7661 (Permits)	The proposed project would be considered a federal major source and subject to the Title V Operating Permit Program. Title V permits consolidate federally enforceable operating limits. AEC would exceed major source thresholds and a Title V permit would be required. AEC has submitted an application to SCAQMD to modify the existing Title V permit. The Title V program is within the jurisdiction of the SCAQMD with U.S. EPA oversight (see SCAQMD Regulation XXX).

Applicable LORS	Description
Title 40 CFR Part 72 (Permits Regulation)	Electrical generating units greater than 25 MW are subject to the provisions involving NOx and SO_2 reductions. Requires a Title IV permit and compliance with acid rain provisions, implemented through the Title V program. This program is within the jurisdiction of the SCAQMD with U.S. EPA oversight.
State	**California Air Resources Board and Energy Commission**
California Health & Safety Code (H&SC) §21080, 39619.8, 40440.14 (AB 1318)	Requires the executive officer of the SCAQMD, upon making a specified finding, to transfer emission reduction credits for certain pollutants from the SCAQMD's internal emission credit accounts to eligible electrical generating facilities.
H&SC §40910-40930 (District Plans to Attain State Ambient Air Quality Standards)	State Ambient Air Quality Standards should be achieved and maintained. The permitting of the source needs to be consistent with the approved clean air plan. The SCAQMD New Source Review (NSR) program needs to be consistent with regional air quality management plans.
H&SC §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.
H&SC §44300-44384 (Air Toxic "Hot Spots" Information and Assessment)	Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments. The SCAQMD requires participation in a district level inventory and reporting program.
California Public Resources Code §25523(a); 2300-2309 (CEC & ARB Memorandum of Understanding)	Requires that an Energy Commission Decision on a proposed Application for Certification include requirements to assure protection of environmental quality.
Title 13 California Code of Regulations (CCR), §2449 (General Requirements for In-Use Off-Road Diesel Fueled Fleets)	In-Use Off-road Diesel Vehicle Regulation. Imposes idling limits of five minutes, requires a plan for emissions reductions for medium to large fleets, requires all vehicles with engines greater than 25 horsepower (hp) to be reported to the ARB and labeled, and restricts adding older vehicles into fleets.
Title 17 CCR, Subchapter 10 (Climate Change)	Established requirements for mandatory greenhouse gas reporting, verification and other requirements pursuant to cap and trade regulations.
Title 20 CCR, §2900-2913 (Provisions Applicable to Power Plants 10 MW and Larger)	Establishes the greenhouse gases emission performance standard (EPS), applicable to 10 MW and larger power plants (SB1368).
Local	**South Coast Air Quality Management District**
Regulation II – Permits	This regulation sets forth the regulatory framework of the application for issuance of construction and operation permits for new, altered and existing equipment. **Rule 201 –** Permit to Construct. Established procedures for the review of new and modified emission sources through the issuance of permits. No further analysis necessary. **Rule 201.1** – Permit Conditions in Federally Issued Permits to Construct. Establishes requirements for federal permits. No further analysis necessary. **Rule 212 –** Standards for Approving Permits and Issuing Public Notice. Outlines specific criteria for approving permits and issuing public notice. Includes requirements for RECLAIM facilities. **Rule 218 –** Continuous Emission Monitoring. Requires specified facilities to install and maintain stack monitoring systems. The proposed project would be required to install and maintain stack monitoring systems by permit condition. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements.

Applicable LORS	Description
Regulation III – Fees	**Rule 301 –** Permitting and Associated Fees. Establishes application fees for the SCAQMD.
Regulation IV – Prohibitions	This regulation sets forth the restrictions for visible emissions, odor, nuisance, fugitive dust, various air emissions, and fuel contaminants. This regulation also specifies additional performance standards for specific emission units. **Rule 401 –** Visible Emissions. Establishes limits on visible emissions from stationary sources. **Rule 402 –** Nuisance. Prohibits the discharge of air contaminants or other material which could cause injury, detriment, nuisance or annoyance to the public or could damage business or property. **Rule 403 –** Fugitive Dust. Establishes requirements for controlling man-made fugitive dust. The provisions apply to any activity of man-made condition capable of generating fugitive dust. **Rule 404 –** Particulate Matter -Concentration. Specifies standards for particulate matter emission concentrations based on exhaust flow rate. This rule is not applicable to emissions from the combustion of gaseous fuels in steam generators or combustion turbines. **Rule 407 –** Liquid and Gaseous Contaminants. Limits emissions of CO and sulfur compounds calculated as sulfur dioxide (SO_2) from stationary sources. **Rule 408 –** Circumvention. Prohibits hidden or secondary rule violations. No further analysis required. **Rule 409 –** Combustion Contaminants. Limits total particulate emissions on a density basis. **Rule 429 –** Start-Up and Shutdown Exemption Provisions for Oxides of Nitrogen. Establishes limited exemptions during start up and shutdown and establishes record-keeping provisions. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. **Rule 430 –** Breakdown Provisions. Requires the reporting of breakdowns and excess emissions. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. **Rule 431.1 –** Sulfur Content of Gaseous Fuels. Limits sulfur content in gaseous fuels to reduce SOx emissions. **Rule 474 –**Fuel Burning Equipment –Oxides of Nitrogen. Establishes limits for NOx emissions from stationary sources. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. **Rule 475 –** Electric Power Generating Equipment. Limits combustion contaminant (PM10) emissions from any equipment with a maximum rating of more than 10 MW used to produce electric power. Combustion contaminants are limited to 11 pounds per hour and 0.01 grains per dry standard cubic feet (gr/dscf) calculated at 3 percent O_2 over 15 consecutive minutes. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. **Rule 476 -** Steam Generating Equipment. Limits NOx and particulate matter and specifies monitoring and recordkeeping from steam generating equipment with heat input ratings over 50 MMBtu/hr.
Regulation IX: Standards of Performance for New Stationary Sources (NSPS)	Adopts national standards of performance provisions from Part 60 in the CFR for specific source categories. Establishes the SCAQMD as the Administrator for specific source standards of performance.

Applicable LORS	Description
Regulation X: National Emission Standards for Hazardous Air Pollutants (NESHAPS)	Adopts national emission standards for hazardous air pollutants from Part 63 in the CFR for specific source categories. Establishes the SCAQMD as the Administrator for specific source standards.
Regulation XI: Source Specific Standards	Establishes requirements for specific source categories. **Rule 1134 –** Emissions of Oxides of Nitrogen from Stationary Gas Turbines. Establishes NOx limits and monitoring and testing requirements for applicable gas turbines. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. **Rule 1135 –** Emissions of Oxides of Nitrogen from Electric Power Generating Systems. Establishes NOx limits and monitoring and testing requirements for applicable electric power generating systems. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements. No further analysis necessary. **Rule 1146 –** Emissions of Oxides of Nitrogen from Industrial, Institutional and Commercial Boilers, Steam Generators, and Process Heaters. Establishes NOx limits and monitoring and testing requirements for applicable boilers. Per Rule 2001, RECLAIM facilities for NOx and SOx are exempt from NOx and SOx requirements.
Regulation XIII: New Source Review	Establishes the pre-construction review requirements for new, modified or relocated facilities to ensure that these facilities do not interfere with progress in attainment of the national ambient air quality standards and that future economic growth in the SCAQMD is not unnecessarily restricted. For RECLAIM facilities this regulation only applies to pollutants not addressed by Regulation XX (RECLAIM). **Rule 1303 –** Requirements. Establishes Best Available Control Technology (BACT), modeling and offset requirements. **Rule 1304/1304.1 –** Exemption. Establishes modeling and offset exemptions for specific categories including electric utility steam boiler replacements. A fee is established for projects utilizing the exemption. **Rule 1313 –** Permits to Operate. Established requirements for the existing AGS. **Rule 1325 –** Federal PM2.5 New Source Review Program. Outlines requirements for PM2.5 for any new major polluting facility or major modification to a major polluting facility located in areas designated as nonattainment for PM2.5.Establishes the use of lowest achievable emission rate (LAER), offsets, certification of compliance with emission limits and alternative analysis for applicable projects. SCAQMD adopted an update to this rule but the effective date is likely to be after the Energy Commission decision for AEC.
Regulation XIV: Toxics and Other Non-Criteria Pollutants	**Rule 1401 –** New Source review of Toxic Air Contaminants. Specifies limits for maximum individual cancer risk and acute and chronic hazard index for modifications to existing facilities emitting toxic air contaminants. Best Available Control Technology for Toxics (T-BACT) is required for projects with potential exposures over an established threshold. **Rule 1401.1 –** Requirements for New and Relocated Facilities Near Schools. Established additional health protection for children at schools located within 500 feet of new facilities.

Applicable LORS	Description
Regulation XVII: Prevention of Significant Deterioration	Prevention of Significant Deterioration (PSD). Establishes requirements for preconstruction review to ensure that the air quality in attainment does not significantly deteriorate and maintains a margin for future growth. Requirements for PSD review include use of BACT, modeling, and impact analysis. SCAQMD has partial delegation of PSD authority from the U.S. EPA depending on the calculation methodology and plant wide applicability limits. **Rule 1701, 1702, 1706** – Applicability. Establishes applicability requirements for PSD. **Rule 1703 –** Top Down BACT, Certificate of Compliance, Copy of Application, Analysis. Establishes process to perform Top-Down BACT analysis, requires certification of compliance and distribution to affected agencies and establishes procedures for analysis. **Rule 1714 –** Prevention of Significant Deterioration for Greenhouse Gases. Establishes requirements for the review of GHGs. Review includes a BACT analysis however modeling and monitoring is not required for GHGs.
Regulation XX: Regional Clean Air Incentives Market (RECLAIM)	RECLAIM is designed to allow facilities flexibility in achieving emission reduction requirements for NOx and SOx through controls, equipment modifications, reformulated products, operational changes, shutdowns, other reasonable mitigation measures or the purchase of excess emission reductions. **Rule 2005 –** New Source review for RECLAIM. BACT is required for increases of any nonattainment air contaminant, ozone-depleting compound or ammonia. Major sources must also verify that all stationary sources in jurisdiction of the project are in compliance with the CAA. Alternative analysis, compliance through CEQA, visibility protection, public notice, compliance –including compliance with state and federal NSR are all included in the RECLAIM analysis. **Rule 2011 –** Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions. Outlines the specific monitoring and reporting requirements for SOx. **Rule 2012 –** Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions. Outlines the specific monitoring and reporting requirements for NOx.
Regulation XXX: Title V Permits	The Title V federal program is the air pollution control permit system required by the CAA as amended in 1990. Regulation XXX defines the permit application and issuance as well as compliance requirements associated with the program. Any new or modified major source which qualifies as a Title V facility must obtain a Title V permit prior to construction, operation or modification of that source. Regulation XXX also integrates the Title V permit with the RECLAIM program such that a project cannot proceed without both.
Regulation XXXI Acid Rain Permits	Title IV of the federal Clean Air Act provides for the issuance of acid rain permits for qualifying facilities. Regulation XXXI integrates the Title V program with the RECLAIM program. Regulation XXXI requires a subject facility to obtain emission allowances for SOx emissions as well as monitoring SOx, NOx, and CO_2 emissions from the facility.

ENVIRONMENTAL IMPACT ANALYSIS

SETTING

The proposed project site is in the city of Long Beach in Los Angeles County. The AEC would be located in the South Coast Air Basin (SCAB). The proposed AEC site is a gently sloping coastal terrace above the Alamitos Bay Marina. There are no significant terrain features within the immediate area surrounding the AEC site. The only complex terrain feature within 6 miles of the AEC is Signal Hill, a city on a hill surrounded by the city of Long Beach. Signal Hill is approximately 365 feet above Long Beach and is not considered a significant terrain feature due to the gradual rise and small width.

The AEC would be located on approximately 21 acres of a 71-acre parcel within the existing AGS site located at 690 N. Studebaker Road. The 71-acre site is bordered by the SCE switchyard and State Route 22 to the north, the San Gabriel River and Los Angeles Department of Water and Power Haynes Generating Station to the east, the former Plains West Coast Terminals petroleum storage facility and some undeveloped property to the south, and the Los Cerritos channel, AGS cooling water canals, and residences to the west. The Rosie the Riveter Charter High School is located on the northwest corner of the AGS parcel.

CLIMATE AND METEOROLOGY

The dispersion of pollutants in the atmosphere affects the air quality in the region. Meteorological conditions such as wind velocity, atmospheric turbulence, stability, temperature and humidity all play a role in how pollutants are dispersed.

The climate of the South Coast Air Basin (SCAB) is strongly influenced by local terrain and geography. The SCAB is a coastal plain with connecting broad valleys and low hills, bounded by the Pacific Ocean on the west and south, and the San Gabriel, San Bernardino and San Jacinto Mountains to the north, and east. The climate is mild, tempered by cool sea breezes and is dominated by the semi-permanent high pressure of the eastern Pacific. The mild climatological pattern is interrupted infrequently by periods of extremely hot weather, winter storms, and Santa Ana winds.

The Long Beach WSCMO climatological station (045085) is located near the AEC site. The station measures site data including precipitation, temperature, humidity and wind movement. Information from the station indicates December and January are the coldest months, while the warmest month is August. The monthly average high is 84 degrees Fahrenheit in August and record highs of 111 degrees Fahrenheit have been reported in September and October of 2011. The annual average high is 74 degrees Fahrenheit and the average annual low is reported as 55 degrees Fahrenheit. The monthly average low is reported as 46 degrees Fahrenheit in January and December. The majority of the rainfall falls during the period from October through April, and the maximum average precipitation occurs in February. The annual average rainfall is reported as12.01 inches per year (WRCC 2016).

Wind flow patterns affect air movement in the atmosphere and influence the transport of pollutants to and from the site. The applicant provided quarterly and annual wind rose data collected at the Long Beach station from 2006-2009 and 2011. The data displays the wind direction, speed and frequency at the monitoring site. The most predominant annual wind direction is from the west. There are also less frequent winds from the south and northeast occurring throughout the year. The annual average wind speed is 1.89 meters/second (m/s).

Along with the wind flow, atmospheric stability and mixing heights are important factors in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, which results in more mixing and better dispersion. The vertical temperature profile influences the atmospheric stability of a region. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds within the mixing layer. In general, mixing is more limited at night and in the winter in the basin when there is a higher potential for lower level inversion layers being present along with low speed surface winds.

The southern California coast is characterized by the cooling effect of the ocean on the surface air. As the surface air cools, it becomes denser than the warmer air above it producing an inversion layer. Inversion layers are formed when temperature increases with height. Inversion layers are present on approximately 87 percent of the days in the year along the southern California coast. The inversion layer forms a stable layer that limits the mixing of air near the surface and therefore pollutants tends to be trapped close to the surface.

The meteorological conditions present affect the formation and concentrations of air pollutants. The potential for high concentrations of pollutants can vary seasonally. Temperature can influence the vertical mixing height and affects chemical and photochemical reaction time. During late spring, summer and early fall, light winds, low mixing heights and sunshine combine to create an environment favorable to the production of photochemical oxidants, particularly ozone. During the spring and summer, deep marine layers are frequently formed along the southern California coast and sulfate concentrations are at their peak.

Representative meteorological data is used in the dispersion modeling analysis to determine potential project impacts. The SCAQMD and U.S. EPA both have criteria for the data used for modeling. It is generally recommended that meteorological data from the closest station to the project site be used. However, besides proximity the guidelines also take into consideration the complexity of the terrain, the exposure of the meteorological monitoring site and the period of time the data is collected.

SCAQMD runs two monitoring stations in close proximity to the proposed site that collect meteorological data. The North Long Beach station is located 6.4 miles northwest of the project site and the Anaheim station is located 10.1 miles to the east-northeast of the project site. The meteorological data collected at the North Long Beach site was selected for the modeling because the station is the closest to the proposed site, there is no complex terrain between the station and the proposed site, and the land uses surrounding the monitoring site and AEC are similar. Specifically both are surrounded by a mix of low, medium and high intensity land use and have open water within 10 miles to the south-southwest.

AMBIENT AIR QUALITY STANDARDS

The U.S. EPA and the ARB have both established allowable maximum ambient concentrations of criteria air pollutants. These are based upon public health impacts and are called ambient air quality standards. The California Ambient Air Quality Standards (CAAQS), established by ARB, are typically lower (more stringent) than the federally established NAAQS.

Ambient air quality standards are designed to protect people who are most susceptible to respiratory distress such as asthmatics, the elderly, very young children, people already weakened by other disease or illness, and people engaged in strenuous work or exercise. The ambient air quality standards are also set to protect public welfare, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.

Current state and federal ambient air quality standards are listed in **Air Quality Table 2**. The averaging time for the various ambient air quality standards (the duration of time the measurements are taken and averaged) ranges from one hour to one year. The standards are read as a concentration, in ppm, parts per billion (ppb), or as a weighted mass of material per unit volume of air, in milligrams (mg) or micrograms (µg) of pollutant in a cubic meter (m^3) of ambient air, drawn over the applicable averaging period.

Air Quality Table 2
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	8 Hour	0.070 ppm (137 µg/m^3)[a]	0.070 ppm (137 µg/m^3)
	1 Hour	—	0.09 ppm (180 µg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual	53 ppb (100 µg/m^3)	30 ppb (57 µg/m^3)
	1 Hour	100 ppb (188 µg/m^3)[b]	180 ppb (339 µg/m^3)
Sulfur Dioxide (SO_2)	24 Hour	—	0.04 ppm (105 µg/m^3)
	3 Hour	0.5 ppm (1300 µg/m^3)	—
	1 Hour	75 ppb (196 µg/m^3)[c]	0.25 ppm (655 µg/m^3)
Respirable Particulate Matter (PM10)	Annual	—	20 µg/m^3
	24 Hour	150 µg/m^3	50 µg/m^3
Fine Particulate Matter (PM2.5)	Annual	12 µg/m^3	12 µg/m^3
	24 Hour	35 µg/m^3 [b]	—
Sulfates (SO_4)	24 Hour	—	25 µg/m^3

Pollutant	Averaging Time	Federal Standard	California Standard
Lead	30 Day Average	—	1.5 μg/m^3
	Rolling 3-Month Average	1.5 μg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42 μg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.01 ppm (26 μg/m^3)
Visibility Reducing Particulates	8 Hour	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

Source: ARB 2015c, U.S. EPA 2016 a,b
Note: [a] Fourth- highest maximum 8 – hour concentration, averaged over 3 years.
[b] 98th percentile of daily maximum value, averaged over 3 years
[c] 99th percentile of daily maximum value, averaged over 3 years

AMBIENT AIR QUALITY ATTAINMENT STATUS

The U.S. EPA, ARB, and the local air district have established air monitoring plans designed to obtain representative data on the ambient levels of pollutants. This data is used to classify an area as attainment, unclassified, or nonattainment, depending on whether or not the monitored ambient air quality data indicates compliance, insufficient data is available, or non-compliance with the ambient air quality standards, respectively. In general, an area is designated as attainment if the concentration of a particular air contaminant does not exceed the standard. Likewise, an area is designated as nonattainment for an air contaminant if that contaminated standard is violated.

Exceptional events that are out of human control that create very high pollutant concentrations such as wind storms and fires are generally excluded from attainment designations. In circumstances where there is not enough ambient data available to support designations as either attainment or nonattainment, the area can be designated as unclassified or unclassifiable. An unclassified area is normally treated the same as an attainment area for regulatory purposes. In addition, an area could be designated as attainment for one air contaminant while nonattainment for another, or attainment for the federal standard and nonattainment for the state standards for the same air contaminant.

The federal and state attainment status for specified pollutants in the SCAQMD is summarized in **Air Quality Table 3**. This area is designated as nonattainment for the federal and state ozone, state PM10 (both 24-hr and annual standards) and PM2.5 standards. The SCAQMD is designated as attainment or unclassified for federal PM10 (national 24-hour standard), CO, NO_2, and SO_2. Los Angeles County is also currently classified as federal nonattainment for lead (Pb).

Air Quality Table 3
Attainment Status of South Coast Air Quality Management District (SCAQMD)

Pollutants	Attainment Status	
	Federal Classification	**State Classification**
Ozone (1-hr)	No Federal Standard[a]	**Nonattainment**
Ozone (8-hr)	**Nonattainment**	**Nonattainment**
CO	Unclassified/Attainment	Attainment
NO_2	Unclassified/Attainment	Attainment
SO_2	Attainment	Attainment
PM10	Attainment	**Nonattainment**
PM2.5	**Nonattainment**	**Nonattainment**
Sulfates	No Federal Standard	Attainment
Lead	**Nonattainment**[b]	Attainment
Hydrogen Sulfide (H2S)	No Federal Standard	Unclassified
Visibility Reducing Particulates	No Federal Standard	Unclassified

Source: ARB 2016a, EPA 2016 a,b.
Note: [a] The federal 1-hour standard was revoked in June 2005, however the South Coast Air Basin has not attained this standard and is subject to anti-backsliding requirements.
Note: [b] Los Angeles County portion of the basin.

AMBIENT AIR QUALITY MONITORING STATIONS

There are several monitoring stations located near the project site summarized in **Air Quality Table 4**. South Coast Los Angeles County 2 (South Long Beach) station is located approximately 4.6 miles northwest of the project site. The South Long Beach station has been in operation since 2003 and monitors PM10, PM2.5, lead, and SO_4. The South Coast Los Angeles County 1(North Long Beach) station is located 6.4 miles northwest and currently measures PM2.5. Prior to the decommissioning in September, 2013 the North Long Beach monitoring site measured O_3, NO_2, CO, SO_2, PM10, PM2.5, and lead. Currently, this station only monitors PM2.5. The South Coastal Los Angeles 3 (Hudson Long Beach) station is located approximately 7.2 miles northwest of the project site and monitors O_3, NO_2, CO, SO_2, and PM10. The Long Beach Route 710 station is located approximately 8.5 miles north-northwest and measures NO_2 and PM2.5.The Central Orange County (Anaheim) station is located 10.1 miles to the east-northeast and measures O_3, NO_2, CO, PM10, and PM2.5. The South Central Los Angeles County (Compton) station is located 10.9 miles north-northwest and measures O_3, NO_2, CO, PM10, PM2.5, and lead. An additional monitoring station, Long Beach Route 710, was also identified. This site is not included because it is a new monitoring station and the duration of the record is too short.

Air Quality Table 4
Pollutant Monitoring Summary of Surrounding Stations

Monitoring Station	Distance	Ozone	NO_2	CO	SO_2	PM10	PM2.5
South Coastal Los Angeles County 2 (South Long Beach)[a]	4.6 NW	N/A	N/A	N/A	N/A	Yes	Yes
South Coastal Los Angeles County 1 (North Long Beach)[a,b]	6.4 NW	Yes	Yes	Yes	Yes	Yes	Yes
South Coastal Los Angeles County 3 (Long Beach or Hudson)	7.2 NW	Yes	Yes	Yes	Yes	Yes	N/A
Los Angeles County (Long Beach Route 710)	8.5 NNW	N/A	Yes	N/A	N/A	N/A	Yes
Central Orange County (Anaheim)	10.1 ENE	Yes	Yes	Yes	N/A	Yes	Yes
South Central Los Angeles County (Compton)[a]	10.9 NNW	Yes	Yes	Yes	N/A	N/A	Yes

Source: AEC2013a, CH2 2016s, staff analysis
Note: N/A indicates no data for this pollutant.
Note: [a] Station also monitors lead.
Note: [b] Station currently only monitors PM2.5.

The maximum ambient background concentration is used in combination with the modeled pollutant concentrations from the project in order to assess potential impacts from the project. According to federal requirements, the background data used to evaluate the potential air quality impacts needs to be representative but it is not required to be collected at the project site. The ambient concentrations of criteria pollutants for at least three years from ARB certified monitoring sites is evaluated to determine appropriate background ambient concentrations of criteria pollutants at the proposed project site. The selection of background data was based on location, data quality and time period of the data collected.

The data from the monitoring stations identified in **Air Quality Table 4** were considered for use as representative data in the impact analysis. The South Long Beach monitoring station is the closest station to the proposed project site; however, the station only measures limited pollutants. The station measures the pollutants at a neighborhood scale and is considered to be a highest concentration type monitoring site for these pollutants. The South Long Beach station is considered to be representative of the project site. The impact analysis required for both PM10 and PM2.5 will use data from this monitoring station as representative.

The North Long Beach monitoring station is the next closest station to the proposed project site and measures each of the pollutants required in the air quality impact analysis. The station is located close to the Port of Long Beach and the Long Beach airport. The station measures pollutants on either a microscale, middle scale or neighborhood scale basis and is considered to be representative of highest concentrations or population exposure depending on the specific pollutant.

The Hudson monitoring station is slightly further away from the proposed AEC site than the North Long Beach station. The Hudson monitoring station measures pollutants on a microscale basis and is considered to collect data representing the highest concentrations. The SCAQMD has requested hourly NO_2 data from this monitor be used as representative background data for hourly NO_2 impact assessment. AES proposed the use the North Long Beach monitoring data for annual background NO_2 in the impact analysis. **Air Quality Table 5** includes data from both of these sites; the analysis is based upon the conservative concentrations measured at the Hudson monitoring station.

Data from several monitoring sites were not considered for use as representative data in the impact analysis. The Long Beach Route 710 station began operation in January 2015. Due to the limited data available from this station, it is not known if the station data could be classified as representative background data. The Anaheim station is downwind to the proposed site but is further away and more inland than several other monitoring stations. The Compton station is further away and more inland than the other sites and is therefore not considered representative of the project site. Therefore the Long Beach Route 710, Anaheim and Compton monitoring stations ware not evaluated any further in this analysis.

Ambient data collected at the South Long Beach monitoring station was used as representative background data for PM10 and PM2.5. Ambient data collected at the North Long Beach station was used as representative data for other pollutants not measured at the South Long Beach monitoring station with the exception of NO_2. The SCAQMD used NO_2 data from the Long Beach monitoring station. The Long Beach station was commissioned in 2010. U.S. EPA Region 9 believes that is representative and captures large NOx sources in the Port area upwind from the project site.

CRITERIA POLLUTANTS

Ambient monitoring data for select criteria pollutants (nitrogen dioxide, ozone, particulate matter, carbon monoxide and sulfur dioxide) collected from 2009 to 2014 from the monitoring stations near the project site is summarized in the following tables. Data marked in bold indicate that the current standard was exceeded in that period. Note that an exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.

Nitrogen Dioxide (NO_2)

NO_2 is a component of a group of highly reactive gases collectively known as NOx. NOx includes NO and NO_2. NOx is formed from the reaction of nitrogen and oxygen during combustion. Approximately 75 to 90 percent of the NOx emitted from combustion sources is NO. NO is oxidized in the atmosphere to NO_2 through reactions with oxidants such as oxygen and ozone. NO and oxygen slowly react to form NO_2. NO and ozone reactions occur primarily during the nighttime without the presence of sunlight. Sunlight can cause NO_2 to disintegrate into NO and O_2. High ambient concentrations of NO_2 usually occur during the fall and winter when atmospheric conditions tend to trap ground-level emissions but lack significant photochemical activity due to less sunlight. NO_2 concentrations are more prevalent during midmorning than midday or afternoon. In the summer, NO is converted to NO_2, but the relatively high temperatures and windy conditions (atmospheric unstable conditions) generally disperse pollutants and also engage NO in reactions with VOCs to form ozone. The formation of NO_2 in the presence of ozone is according to the following reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

Urban areas typically have high daytime ozone concentrations that drop substantially at night as the above reaction takes place, and ozone scavenges the available NO. If ozone is unavailable to oxidize the NO, less NO_2 will form because the reaction is "ozone-limited." This reaction explains why, in urban areas, ground-level ozone concentrations drop at night, while aloft and in downwind rural areas (without sources of fresh NO emissions), nighttime ozone concentrations can remain relatively high.

The U.S. EPA implemented a 1-hour NO_2 standard of 0.1 ppm, which became effective on April 12, 2010. The new standard is expressed as a 3-year average of the 98th percentile of the daily maximum 1-hour concentration (i.e., the 8th highest of daily highest 1-hour concentrations). **Air Quality Table 5** includes the maximum 1-hour NO_2 concentrations, the 1-hour 98th percentile average, and the annual arithmetic mean at North Long Beach and Long Beach stations. NO_2 concentrations measured at these stations from 2009 to 2014 do not exceed either the federal or state standards. The SCAQMD is currently designated as unclassified/attainment for the federal NO_2 standard. On February 26, 2014, the 2013 amendment to area designations for the state standards were finalized classifying the South Coast Air Basin in attainment for the state NO_2 standard.

Air Quality Table 5
Nitrogen Dioxide Concentrations, 2009-2014

Nitrogen Dioxide (ppm)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
North Long Beach	1-hour (Max)	0.11	0.0928	0.1064	0.0772	0.0669	----
	1-hour (98th)	0.07	0.0702	0.0676	0.0625	0.0557	----
	Annual	0.0212	0.0198	0.0177	0.0208	0.0140	----
Hudson Long Beach	1-hour (Max)	----	0.1178	0.0900	0.0978	0.0813	0.1359
	1-hour (98th)	----	0.0710	0.0740	0.0774	0.0713	0.0848
	Annual	----	0.022	0.0212	0.0253	0.0215	0.0207

Source: SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Ozone

Ozone is a colorless gas found in two regions of the atmosphere. In the upper region, it protects the earth from harmful rays from the sun. In the lower region, ozone forms what is generally called smog. Ozone is not directly emitted from stationary or mobile sources. It is a secondary pollutant formed through complex chemical reactions between NOx, and VOCs in the presence of sunlight. Ozone formation is highest in the summer and fall when abundant sunshine and high temperatures trigger the necessary photochemical reactions, and lowest in the winter. The days with the highest ozone concentrations in this region commonly occur between May and October. The SCAQMD is classified as a nonattainment area with respect to both state and national ambient air quality standards for ozone. **Air Quality Table 6** displays the maximum 1-hour and 8-hour concentrations at both the North Long Beach and Hudson Long Beach stations.

Air Quality Table 6
Ozone Concentrations, 2009-2014

Ozone (ppm)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
North Long Beach	1-hour	0.089	0.101	0.073	0.084	**0.092**	----
	8-hour	0.068	**0.084**	0.061	0.067	0.070	----
Hudson Long Beach	1-hour	----	**0.099**	0.074	0.080	0.090	0.087
	8-hour	----	**0.084**	0.063	0.066	0.069	**0.072**

Source: SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Respirable Particulate Matter (PM10)

PM10 is a mixture of small solid particles and liquid droplets with a size less than or equal to 10 microns diameter. PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx, and VOC from turbines, and ammonia from NOx control equipment, given the right meteorological conditions, can form particulate matter in the form of nitrates, SO_4, and organic particles. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid originates from NOx emissions from combustion sources. The nitrate ion concentrations during the wintertime are a significant portion of the total PM10, and an even higher contributor to PM2.5, described more fully below. The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) or sodium nitrate.

As shown with 2009-2014 monitoring data included in **Air Quality Table 7**, the CAAQS 24-hour and annual standards have been exceeded at both the South Long Beach and North Beach monitoring stations. The federal 24-hour PM10 standard of 150 µg/m3 has not been exceeded at the stations near the project site from 2009 through 2014. The SCAQMD is characterized as nonattainment for the state 24-hour and annual PM10 standard and attainment/maintenance for the federal 24-hour PM10 standard. The SCAQMD redesignation of attainment and PM10 maintenance plan was approved by the U.S. EPA in 2013.

Air Quality Table 7
Particulate Matter Less Than 10 Microns, 2009-2014

PM10 (µg/m^3)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
South Long Beach	24-hour	**83**	**76**	50	**54**	**54**	**59**
	Annual	**33.2**	**27.3**	**28.7**	**25.5**	**27.3**	**26.6**
North Long Beach	24-hour	**62**	44	43	45	37	----
	Annual	**30.5**	**22.0**	**24.2**	**23.3**	**23.2**	----

Source: SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Fine Particulate Matter (PM2.5)

PM2.5 refers to particles and droplets with a diameter less than or equal to 2.5 microns. PM 2.5 is believed to pose a greater health risk than PM10 because it can lodge deeply into the lungs due to the small size. PM2.5 includes nitrates, sulfates, organic carbon and elemental carbon, which mainly result from combustion and atmospheric reactions. Almost all combustion-related particles, including those from wood smoke and cooking, are smaller than 2.5 microns. Nitrate and sulfate particles are formed through complex chemical reactions in the atmosphere. Particulate nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NOx emissions from combustion sources. The nitrate ion concentrations during the winter make up a large portion of the total PM2.5.

Air Quality Table 8 summarizes the ambient PM2.5 data collected from the surrounding stations. The national 24-hour average NAAQS is met if the 3-year average of the 98th percentile concentration is 35 μg/m^3 or lower. The high 24-hour average maximum concentrations listed in **Air Quality Table 8** include values above the NAAQS standard. The maximum 24-hour concentrations however do not reflect the 3-year 98th percentile designation value. The 3-year 98th percentile values were not exceeded at either the South Long Beach or North Long Beach stations. The state and federal annual arithmetic mean designation value was exceeded at both the South Long beach and North Long Beach stations in 2009. For purpose of state and federal air quality planning and permitting, the SCAQMD is classified as nonattainment with both the federal and state PM2.5 standards.

Air Quality Table 8
Particulate Matter Less Than 2.5 Microns, 2009-2014

PM2.5 (μg/m^3)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
South Long Beach	24-hour (Max)	**55.8**	33.7	**42.0**	**46.7**	**42.9**	**52.2**
	24-hour (98th)	30.5	26.5	26.6	25.1	24.6	27.2
	Annual	**12.5**	10.4	10.7	10.57	10.97	10.72
North Long Beach	24-hour (Max)	**63**	35.0	**39.7**	**49.8**	**47.2**	**51.5**
	24-hour (98th)	34.2	28.3	27.8	26.4	26.1	31.3
	Annual	13.0	10.5	11.0	10.37	11.34	11.42

Source: SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Carbon Monoxide

Carbon monoxide is a product of incomplete combustion due to the insufficiency of oxygen content at the point of combustion. Mobile sources are the main sources of CO emissions. Ambient concentrations of CO are highly dependent on motor vehicle activity. CO is a local pollutant, with high concentrations usually found near the emission sources. The highest CO concentrations occur during rush hour traffic in the mornings and afternoons. Ambient CO concentrations attain the air quality standards due to two statewide programs: 1) the 1992 wintertime oxygenated gasoline program, 2) Phase I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to reduced CO emissions. **Air Quality Table 9** includes the maximum 1-hour and 8-hour CO concentrations from the North Long Beach and Hudson Long Beach monitoring stations. These values are well below respective ambient air quality standards.

Air Quality Table 9
Carbon Monoxide, 2009-2014

Carbon Monoxide (ppm)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
North Long Beach	1-hour	2.9	3.2	3.2	2.6	2.7	----
	8-hour	2.2	2.1	2.6	2.2	1.9	----
Hudson Long Beach	1-hour	----	4.1	3.7	4.2	4.1	3.7
	8-hour	----	2.6	3.3	2.6	2.6	2.6

SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Sulfur Dioxide

Sulfur dioxide is typically emitted as a result of the combustion of fuels containing sulfur. This proposed project would use natural gas, which contains very little sulfur and consequently has very low SO_2 emissions when burned. By contrast, fuels with high sulfur content, such as coal, emit very large amounts of SO_2 when burned. Sources of SO_2 emissions come from every economic sector and include a wide variety of fuels in gaseous, liquid and solid forms. The whole state is designated attainment for all state and federal SO_2 ambient air quality standards. **Air Quality Table 10** includes maximum state1-hour, federal 1-hour, and 24-hour SO_2 concentrations at the North Long Beach and Long beach stations.

Air Quality Table 10
Sulfur Dioxide, 2009-2014

Sulfur Dioxide (ppb)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
North Long Beach	1-hour (Max)	17	40.0	14.8	22.2	21.8	----
	1-hour (99^{th})	12	16	10.7	14.3	10.1	----
	24-hour	4.4	6	4.1	3	1.7	----
Hudson Long Beach	1-hour (Max)	----	35.6	43.3	22.7	15.1	14.7
	1-hour (99^{th})	----	16	24.7	21.3	11.6	10.1
	24-hour	----	4.4	11.6	4	3.9	3

SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

Visibility

Visibility in the region of the project site depends upon the area's natural relative humidity and the intensity of both particulate and gaseous pollution in the atmosphere. The most straightforward characterization of visibility is probably the visual range (the greatest distance that a large dark object can be seen). However, in order to characterize visibility over a range of distances, it is more common to analyze the changes in visibility in terms of the change in light-extinction that occurs over each additional kilometer of distance (1/km). In the case of a greater light-extinction, the visual range would decrease.

The SCAQMD is currently designated as unclassified for visibility reducing particles.

Lead

Lead is a naturally occurring metal that is soft and resistant to chemical corrosion. Lead forms compounds with both organic and inorganic substances. Lead has been used for many purposes for thousands of years and has accumulated in the environment. As an air pollutant, lead is present in small particles. Sources of lead emissions include industrial processes and emission from sources using coal and lead-based fuels such as aviation gas. In 1970, the ARB set the CAAQS for lead. In addition, the ARB has identified lead as a toxic air contaminant and is therefore involved in risk management activities for lead. In 1978, U.S. EPA set the NAAQS for lead. The NAAQS was substantially strengthened in 2008.

Lead is monitored as a toxic substance at the South Long Beach and North Long Beach monitoring sites. The SCAB is federally designated partial nonattainment for the Los Angeles County portion of the Basin for near-source monitors. **Air Quality Table 11** includes data from the South Long Beach and North Long Beach monitors. The values are well below respective ambient air quality standards.

Due to the very low concentrations shown in the available ambient monitoring data and the insignificant lead emissions from this project, it is assumed that the project would not create significant impacts based on the ambient lead standards. The Public Health Section provides additional information regarding the quantity of emissions and the health risks of the lead emissions from this project.

Air Quality Table 11
Lead, 2009-2014

Lead (μg/m^3)							
Monitoring Station	**Averaging Time**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
South Long Beach	30-day	0.01	0.01	0.013	0.007	0.012	0.012
	3-month	0.01	0.01	0.009	0.005	0.009	0.01
North Long Beach	30-day	0.01	0.01	0.010	0.005	0.006	----
	3-month	0.01	0.01	0.007	0.005	0.006	----

SCAQMD 2015, ARB 2016a, U.S. EPA 2016c

SUMMARY OF BACKGROUND AMBIENT AIR QUALITY

In summary, staff recommends using the background ambient air quality concentrations in **Air Quality Table 12** as the baseline for the modeling and impacts analysis. The highest criteria pollutant or average concentrations from the last three years of available data collected from the surrounding monitoring stations are used to determine the recommended background values. Concentrations in excess of their ambient air quality standard are shown in bold.

The pollutant modeling analysis was limited to the pollutants listed in **Air Quality Table 12**. Therefore recommended background concentrations were not determined for the other criteria pollutants (ozone, lead, visibility, etc.).

Air Quality Table 12
Staff-Recommended Background Concentrations (µg/m^3)

Pollutant	Averaging Time	Recommended Background	Limiting Standard	Percent of Standard
NO_2	State 1 hour	256	339	75
	Federal 1 hour	146	188	78
	Annual	48	57	84
PM10	24 hour	**59**	50	118
	Annual	**27.3**	20	137
PM2.5	24 hour	27.2	35	89
	Annual	10.97	12	95
CO	1 hour	3,665	23,000	16
	8 hour	2,978	10,000	30
SO_2	1 hour	58	655	9
	Federal 1 hour	31	196	10
	Federal 3 hour	58[a]	1,300	4
	24 hour	11	105	16

Source: SCAQMD 2015, ARB 2016a, U.S. EPA 2016c and staff analysis.
Note: An exceedance is not necessarily a violation of the standard, and that only persistent exceedances lead to designation of an area as nonattainment.
[a] The maximum one hour background is conservatively used for background.

PROJECT DESCRIPTION AND PROPOSED EMISSIONS

The AEC would consist of two natural gas-fired power blocks. Power Block 1 includes two GE Frame 7FA.05 combustion turbine generators (CTGs) with nominal ratings of 227 MW each, and one shared steam turbine generator (STG) with a nominal rating of 229 MW. Each CTG would exhaust to a HRSG without supplemental firing capabilities. Both of the CTG/HRSG trains would feed into the common STG, forming a standard 2-on-1 configuration.

Power Block 1 would also include an air-cooled condenser, a 70.8 MMBtu/hr Babcock and Wilcox auxiliary boiler and related ancillary equipment. The air-cooled condenser for the proposed project would eliminate the existing once-through-cooling system of the existing AGS. The auxiliary boiler would provide enhanced startup times by maintaining the steam cycle in a ready state. Prior to a combined-cycle startup, the auxiliary boiler increases load from a minimum turndown rate to produce steam. The steam is directed to the system for HRSG sparging, turbine seals, pipe warming, condenser dearating and fuel gas heating.

The Power Block 1 operating profile includes multiple operating scenarios based on the operating range of the proposed turbines. The proposed air quality conditions of certification include operating conditions proposed by the SCAQMD. The equipment descriptions included in the SCAQMD conditions is based on the operating scenario yielding the highest BTU/hr consumption. This scenario is identified as Case 1(28 degrees Fahrenheit, maximum load) in the combined-cycle turbine operating scenarios provided in the SAFC. The expected combustion turbine generator rating at Case 1 conditions is 236.645 MW-gross and 235.907 MW-net. The STG is rated at 219.615 MW-gross and 208.965 MW-net at Case 1 conditions. These equipment ratings will be included in the Condition of Certification equipment descriptions.

The two combined-cycle gas turbine Power Block 1 (CCGT) exhaust stacks would be equipped with SCR and CO oxidation catalysts to control NOx, CO and VOC emissions. The SCR will utilize 19% aqueous ammonia as the reducing agent for the SCR system. One new 40,000 gallon tank would be used to store ammonia solution. An oil/water separator would also be used to collect equipment wash water and rainfall.

Power Block 2 would include four 100-MW GE LMS-100PB simple-cycle, intercooled CTGs. Each CTG would include dry low NOx combustors, SCR equipment for NOx reduction and a catalyst to reduce CO emission. Ancillary equipment includes an inlet filter house with an evaporative cooler, turbine intercooler and associated intercooler circulating pumps. Two simple CTGs would share a fin-fan heat exchanger and one generator step up transformer and other ancillary equipment.

The four simple gas turbine Power Block 2 (SCGT) exhaust stacks would be equipped with SCR and CO oxidation catalysts to control NOx, CO and VOC emissions. The SCR will utilize 19% aqueous ammonia as the reducing agent for the SCR system. A second 40,000 gallon tank will be used to store ammonia solution. A second oil/water separator will also be used to collect equipment wash water and rainfall.

No diesel-fueled equipment would be used at this facility.

The proposed AEC would provide fast-starting and stopping capabilities and flexible generating resources. The AEC is proposed to be configured and deployed as a multi-stage generating facility allowing power generation across a wide operating range. The project is proposing multiple generators that could operate singly or in different combinations to provide a large range of generating capacity. The proposed facility would have rapid startup and turndown capabilities and the ability to quickly ramp when needed. The facility would be capable of serving peak and intermediate loads and capable of operating in either load-following or partial shutdown mode. AES is proposing this configuration in order to support the growth of California’s renewable energy portfolio by accommodating the intermittent properties associated with many renewable resources.

The SAFC stated some of the existing infrastructure at the AGS, including two emergency electric-driven fire water pumps, would be reused to the greatest extent possible. Energy Commission staff were informed by AES staff that the construction of AEC would include the installation of two new electric fire pumps. Since the proposed emergency engines are electric, emissions of criteria pollutants do not need to be quantified.

The proposed AEC would be constructed adjacent to the existing AGS. The demolition of existing AGS Units 1-6 equipment and ancillary equipment is not necessary for the construction of the proposed AEC and is therefore not considered part of the scope of the project. AGS Unit 7 has already retired; however, demolition of the unit and associated structures has not been completed. The removal of former Unit 7's building and ancillary equipment, fuel storage tank, tank berms, small maintenance shops and two wastewater retention basins, is needed to prepare the site for the construction of the AEC including Power Block 1. Therefore the remaining demolition of Unit 7 and the remaining site preparation is considered part of the proposed project scope and is evaluated in this analysis.

Existing AGS Units 1-6 will remain in operation throughout the AEC development and construction. Units 1, 2 and 6 will be retired once the AEC CCGT reaches the commissioning stage and becomes operational. Unit 3 would be retired once the AEC SCGT reaches the commissioning stage and becomes operational or by December 31, 2020, whichever occurs first. Units 4 and 5 may operate through December 31, 2020, the once-through-cooling (OTC) Policy compliance deadline. AES originally proposed that units 1, 2, 5, and 3 be retired. On October 26, 2016 AES proposed to retire Unit 6 instead of Unit 5 (CH2 2016hh) SCAQMD accepted the change for the FDOC. Units 5 and 6 are identical in size but were operated different hours in the recent past. The SCAQMD updated the FDOC to incorporate this change.

Separate emissions estimates for the proposed project during the construction phase, initial commissioning, and operation are each described in the following sections.

CONSTRUCTION

Construction of the AEC would consist of the installation of the AEC CCGT and AEC SCGTs and is expected to last approximately 56 months. The AEC will reuse existing onsite water, natural gas, storm water pipelines, and electrical transmission facilities. There is the possibility some modifications may be required to interconnect the AEC facility with these systems. AEC would require a new 1,000 foot process/sanitary wastewater pipeline.

The project would commence with the completion of the demolition of retired AGS Unit 7 scheduled for the first quarter of 2017. Remaining demolition activities for Unit 7 include the removal of former Unit 7's building and ancillary equipment, fuel storage tank, tank berms, small maintenance shops and two wastewater retention basins. The completion of the demolition of Unit 7 is expected by May 2017 and will allow for the construction of the AEC CCGT.

Construction of the AEC CCGT is expected to commence during the second quarter of 2017 and would be completed by the second quarter of 2020. The AEC CCGT is expected to commence commercial operation before May 1, 2020. Construction of the AEC SCGTs is scheduled to start in May 2020 and last until through August 2021. The SCAQMD provided conditions to accommodate the delayed construction of the SCGT units. The SCGTs are expected to begin commercial operation in the third quarter of 2021.

Onsite laydown areas throughout the site would be used during construction. An offsite laydown area of approximately ten acres adjacent to the project site would also be used to store equipment and material during construction. This offsite laydown area is also being proposed for use in the Huntington Beach Energy Project (HBEP). The preparation of this laydown area is expected to occur prior to the proposed construction of AES and associated emissions are included in the HBEP analysis. Due to uncertainty in the schedule for the HBEP and AEC projects, AES indicated there is a potential for the preparation of the adjacent laydown area to overlap with the construction of the AEC.

The proposed construction and demolition equipment would include equipment such as excavators, backhoes, dozers, loaders, cranes, graders, forklifts, aerial lifts, air compressors, generators, pick-up, stake and dump trucks, support vehicles, etc. During the construction period, air emissions would be generated from: 1) vehicle and construction equipment exhaust; 2) fugitive dust from vehicle and construction equipment, including grading, bulldozing and truck loading during construction.

Emissions of NOx, SOx, VOC, CO, PM10, and PM2.5 were quantified for the construction period. Maximum daily and annual emissions were estimated based on the expected construction equipment and workforce. Fugitive dust and construction equipment exhaust emissions were quantified using methodologies and emission factors consistent with the California Emissions Estimator Model. It was assumed the construction equipment would meet Tier 4 final engine control standards and construction activities were assumed to be scheduled for 10 hours per day, 23 days per month. Vehicle exhaust emissions were estimated using EMFAC 2014. Fugitive dust emissions would be mitigated with watering. The control efficiency for mitigation was determined per SCAQMD's CEQA Air Quality Handbook.

Estimates for the maximum daily, maximum monthly and total annual emissions over the 56-month construction period are included in **Air Quality Table 13**. The maximum daily emissions are expected to occur during month 18 for NOx, VOC, CO, and SOx, and during month 20 for PM10 and PM2.5. The maximum annual emissions vary depending on the pollutant. Maximum annual emissions occur between months 14 and 25 for VOC, SOx, and PM2.5, months 13 and 24 for NOx, months 15 and 26 for PM10, and months 16 and 27 for CO. The activity associated with the maximum daily and annual emissions includes the proposed construction of the AEC CCGT.

Air Quality Table 13
AEC, Estimated Maximum Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
Maximum Daily Construction Emissions (lbs/day)	142	7.16	23.4	7.90	113	0.61
Maximum Monthly Construction Emissions (lbs/month)	3,258	165	537	182	2,809	14
Peak Annual Construction Emissions (tons/year)	15.2	0.82	2.73	0.91	14.9	0.069

Source: AEC 2015
Note: Different activities have maximum emissions at different times during the construction period; therefore, total maximum daily, monthly, and annual emissions might be different from the summation of emissions from individual activities.

Estimates for the emissions from the laydown construction area correlated to the HBEP are included in **Air Quality Table 14**.

Air Quality Table 14
Laydown Area Construction Emissions

Construction Activity	NOx	VOC	PM10	PM2.5	CO	SOx
Maximum Daily Emissions (lbs/day)	13.1	1.28	0.96	0.70	6.29	0.0082
Peak Annual Construction Emissions (tons/year)	0.13	0.013	0.010	0.0070	0.063	0.000082

Source: AEC 2014b

INITIAL COMMISSIONING

New electrical generation facilities must go through initial commissioning phases before becoming commercially available to generate electricity. The commissioning period begins when the turbines and boiler are prepared for first fire and ends upon successful completion of initial performance testing. Emissions of NOx, CO, and VOC during the commissioning period are typically higher than during normal operations due to the fact that the combustors may not be optimally tuned and the emission control systems may be only partially operational or not operational at all. The commissioning period is needed to ensure the facility's operation is fine-tuned to minimize emissions during normal operations. The emission rates for PM10, PM2.5 and SOx during initial commissioning are not expected to be higher than normal operating emissions. PM and SOx emissions are proportional to fuel use and the potential maximum fuel use and not the emission control equipment. Emissions from PM10, PM2.5, and SOx are expected to be at or below emissions from full load operations.

The commissioning period for the AEC CCGT is expected to last 6 months. Commissioning activities for the combined-cycle turbines are expected to occur over approximately 1,992 operating hours total for both combustion turbines (996 hours per combustion turbine). During this period, each combustion turbine would require 216 hours of operation without or with partial emission control systems in place. Unabated commissioning activities include 48 hours of CTG testing, 120 hours of steam blows, 12 hours of setting unit HRSG & steam safety valves, 12 hours of dry low NOx (DLN) emissions tuning, and 24 hours of other emissions tuning. Abated commissioning activities include 336 hours of tuning and cleaning activities, 84 hours of pre-performance testing, 168 hours of initial testing, 132 hours of performance testing and 60 hours of California Independent System Operator (California ISO) certification testing per CTG.

Air Quality Table 15 presents the applicant's anticipated maximum commissioning emissions and emission rates of criteria pollutants for the AEC CCGT. Commissioning emissions of NOx, VOC, and CO are estimated based on information from the turbine vendor included in the SAFC. Maximum commissioning emissions for SOx, PM10, and PM2.5 are based on the maximum emission rates at 28 degrees Fahrenheit. Maximum hourly emission rates for NOx, VOC, and CO correspond to the initial CTG testing phase (full speed no load).

Air Quality Table 15
Maximum Initial CCGT Commissioning Emissions

Combined-Cycle	Maximum Commissioning Emissions and Fuel				
	NOx	CO	VOC	SOx[a]	PM10/2.5
Per CTG (lb/hr)	130	1,900	270	4.86	8.5
Total Commissioning (tons/CTG)	13.8	50.7	7.3	2.42	4.23
Total Commissioning (tons)	27.6	101	14.7	4.84	8.47
Total Commissioning (lbs/CTG)	27,597	101,328	14,682	4,841	8,466
Commissioning Fuel Per CTG	1,656.24 (mmcf/CTG)				
Emission Factor (lb,mmcf)	16.66	61.18	8.86	2.92	5.11

Source: CH2 2016s, SCAQMD 2016e and staff analysis.
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

The SCAQMD grouped the commissioning activities by duration to determine expected monthly activities and associated emissions. **Air Quality Table 16** presents the expected maximum monthly commissioning emissions for the AEC CCGT including the month associated with the maximum commissioning emissions. All months is used to designate there is no expected emission difference between the months.

Air Quality Table 16
Maximum Combined-Cycle Monthly Commissioning Emissions

Combined-Cycle	Maximum Monthly Commissioning Emissions				
	NOx	CO	VOC	SOx[a]	PM10/2.5
Maximum Month	1	1	1	5	All Months
Emissions per CTG (lb/month)	14,294	95,023	13,314	809	1,411

Source: SCAQMD 2016e
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas. Due to low emissions and rounding, the estimated SOx emissions vary slightly between the months.

The commissioning period for the AEC SCGT is expected to last 3 months. Commissioning activities for the simple-cycle turbines are expected to occur over approximately 1,120 operating hours total for all four combustion turbines (280 hours per combustion turbine). During this period, each combustion turbine would require up to 4 hours of operation without or with partial emission control systems in place for unit testing. Abated commissioning activities include up to 24 hours of tuning, 12 hours of base load testing, 12 hours of re-firing, 168 hours of initial testing, 24 hours of performance preparation, 24 hours of unit performance testing and 12 hours of California ISO certification per CTG.

Air Quality Table 17 presents the applicant's anticipated maximum commissioning emissions and emission rates of criteria pollutants for the AEC SCGT. Commissioning emissions of NOx, VOC and CO are estimated based on information from the turbine vendor included in the SAFC. Maximum commissioning emissions for SOx, PM10, and PM2.5 are based on the maximum emission rates at 65.3 degrees Fahrenheit. Maximum hourly emission rates for NOx, VOC, and CO correspond to the initial CTG testing phase.

Air Quality Table 17
Maximum Initial Simple-Cycle Commissioning Emissions

Simple-Cycle	Maximum Commissioning Emissions and Fuel				
	NOx	CO	VOC	SOx[a]	PM10/2.5
Per CTG (lb/hr)	40.1	244	5.08	1.62	6.23
Total Commissioning (tons/CTG)	2.9	12.7	0.42	0.23	0.87
Total Commissioning (tons)	11.4	50.8	1.67	0.91	3.49
Total Commissioning (lbs/CTG)	5,772	25,395	836	454	1,744
Commissioning Fuel Per CTG	226.68 (mmcf/CTG)				
Emission Factor (lb/mmcf)	25.24	112.03	3.69	7.69	2.00

Source: SCAQMD 2016e and staff analysis.
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

The SCAQMD grouped the commissioning activities by duration to determine expected monthly activities and associated emissions. **Air Quality Table 18** presents the expected maximum monthly commissioning emissions for the SCGT, including the month associated with the maximum commissioning emissions.

Air Quality Table 18
Maximum Simple-Cycle Monthly Commissioning Emissions

	NOx	CO	VOC	SOx[a]	PM10/2.5
Maximum Month	3	1	3	3	3
Emissions per CTG (lb/month)	1,913	8,594	285	151	583

Source: SCAQMD 2016e.
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

Air Quality Table 19 presents the anticipated maximum commissioning emissions of select criteria pollutants for the AEC auxiliary boiler. The auxiliary boiler commissioning activities includes first burner light-off, conditioning, establishing the air/fuel ratio and SCR ammonia injection curves. The commissioning will occur over five days and will require up to 6 fired hours per day. The commissioning emissions are expected to be the same as two cold startup events (additional details on cold startup emissions for the boiler are presented in the Proposed Operation section below).

Air Quality Table 19
Maximum Initial Boiler Commissioning Emissions

Boiler	Commissioning Emissions (lbs) and Fuel Use		
	NOx	CO	VOC
Daily Emissions	8.44	8.681	9.36
Total Commissioning Emissions	42.2	43.4	46.8
Total Fuel Use	414 MMBtu or 0.39 mmscf		

Source: AEC 2015s, SCAQMD 2016e

PROPOSED OPERATION

After commissioning, the combined-cycle and simple-cycle turbines, and boilers, have different operational modes: startup, shutdown and normal or steady state operation. During turbine startup and shutdown operating modes higher emission rates (relative to steady state operating mode) are expected for VOC, CO, and NOx because the emission control systems are not fully functional or within the operating temperature range. Emissions from the different operational modes are quantified separately based on manufacturer data and engineering estimates.

Combined–Cycle Turbines

The turbine startup events for combined-cycle combustion turbines include three classifications: cold, warm and hot. The air quality conditions of certification includes proposed definitions for these classifications. The events are currently described as follows:

- **Cold Start Event:** The combustion turbine and steam generation system are at ambient temperature at the time of startup. These conditions are expected to occur if the equipment has been non-operational for 48 hours. It can take up to 60 minutes from fuel initiation for the equipment to reach a base load operating rate.
- **Warm Start Event:** The combustion turbine and steam generation system have been non-operational between 10 and 48 hours. It can take up to 30 minutes from fuel initiation for the equipment to reach a base load operating rate.
- **Hot Start Event:** The combustion turbine and steam generation system have been non-operational up to10 hours. It can take up to 30 minutes from fuel initiation for the equipment to reach a base load operating rate.

A shutdown event for the AEC CCGT starts at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. The emissions associated with a shutdown event are expected to be less than startup events but more than normal operation. During the shutdown event, the emission control equipment ceases operation but the SCR and CO catalysts remain at elevated temperatures and control emissions for a portion of the shutdown.

The emission rates for startup and shutdown events for the combined-cycle turbines are summarized in **Air Quality Table 20**. The emission rates for warm and hot startup events are equivalent therefore the categories are combined in the emission calculations in the tables below and the proposed conditions of certification.

Air Quality Table 20
Combined-Cycle Startup and Shutdown Emission Rates Per Turbine

Event Description[a]	Event Duration	Emissions (lbs/event) and (lbs/hour)				
		NOx	CO	VOC	SOx	PM10/2.5
Cold Startup (lbs/event) Cold Startup (lbs/hour)	60 (min)	61.0 61.0	325 325	36.0 36.0	< 4.86 < 4.86	< 8.5 < 8.5
Non-Cold Startup (lbs/event) Non-Cold Startup (lbs/hour)	30 (min)	17.0 25.2	137 142	25.0 27.9	- < 4.86	- < 8.5
Shutdown (lbs/event) Shutdown (lbs/hour)	30 (min)	10.0 18.2	133 138	32.0 34.9	- < 4.86	- < 8.5

Source: CH2 2016s, SCAQMD 2016e and staff analysis.
[a] Staff is recommending the definitions be updated in the FSA

Normal or steady-state operations describe operation for the AEC CCGT when the CTGs, HRSGs, SCR/CO catalysts and STG are functioning as designed. During steady-state operations the emissions are controlled to BACT levels. NOx is controlled to 2.0 ppmvd, CO to 1.5 ppmvd, and VOC to 2.0 ppmvd at 15 percent oxygen. The PDOC and PSA required CO emissions from the CCGT to be controlled to 2.0 ppmvd. The BACT analysis for CO for the CCGT has been updated in the FDOC and FSA. AES confirmed the startup/shutdown emission rates for CO would not be changed due to the reduction in the BACT level for CO (see additional BACT discussion in the Compliance with LORS section). Emission rates for criteria pollutants vary depending on the operational profile of the equipment. The applicant provided estimated emission rates for 11 cases of turbine operation over various loads, and temperatures in the SAFC. An additional 3 cases were provided to the SCAQMD and are included in the SCAQMD FDOC. This information was used to assess maximum emissions using worst-case assumptions. The maximum hourly emission rates for steady-state operations for the AEC CCGT not including startup or shutdown emissions are based on Case 1 conditions and are included in **Air Quality Table 21**.

Air Quality Table 21
Maximum Combined-Cycle Hourly Steady-State Emission Rates

Combined-Cycle	Maximum Hourly Steady-State Emission Rates[a]					
	NOx	**CO**	**VOC**	**SOx[b]**	**PM10/2.5**	**NH_3**
Controlled (ppmvd)	2 (1-hour)	2 (1-hour)	2 (1-hour)	N/A	N/A	5
Emission Rates (lb/hr)	16.5	7.53	5.75	4.86	8.5	15.3

Source: Source: CH2 2016s, SCAQMDe
Note: [a] Based on ambient temperature of 28°F and excluded start-up and shutdown
[b] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

The expected maximum daily, monthly, and annual emissions for the AEC CCGT were determined factoring in potential startup and shutdown events with steady-state operation. The operating profiles used to determine the emission rates and emissions from these operating periods are included in **Air Quality Table 22**.

Air Quality Table 22
Combined-Cycle Operating Profile

Operating Parameters	Events	Hours
Daily		
Cold Startup	2	2
Non-Cold Startup	0	0
Shutdown	2	1
Steady-State	--	21
Total Daily	--	24
Monthly		
Cold Startup	15	15
Non-Cold Startup	47	23.5
Shutdown	62	31
Steady-State	--	674.5
Total Monthly	--	744
Annual		
Cold Startup	80	80
Non-Cold Startup	420	210
Shutdown	500	250
Steady-State		4,100
Total Annually		4,640

Source: CH2 2016s, SCAQMD 2016e and staff analysis.

The expected natural gas use and emissions for the AEC CCGT are included below in the **Total Facility** subsection. For the analysis, commissioning is expected to take a full six months and normal or steady state operation will begin with no overlap with daily or monthly emission estimates.

Simple-Cycle Turbines

The AEC SCGT has one startup scenario and a simpler shutdown sequence. The air quality conditions of certification includes the proposed parameters for the AEC SCGT startup and shutdown events. The emission rates for startup and shutdown events for the simple turbines are summarized in **Air Quality Table 23.**

Air Quality Table 23
Simple-Cycle Startup and Shutdown Emission Rates Per Turbine

Simple-Cycle Event Description	Event Duration	Emissions (lbs/event) and (lbs/hour)				
		NOx	CO	VOC	SOx	PM10/2.5
Startup (lbs/event) Startup (lbs/hour)	30 (min)	16.6 20.7	15.4 19.4	2.80 3.95	0.82 < 1.62	3.12 < 6.23
Shutdown (lbs/event) Shutdown (lbs/hour)	13 (min)/ 0.22 (hr)	3.12 9.56	28.1 34.4	3.06 4.86	0.35 < 1.62	1.35 < 6.23

Source: CH2 2016s, SCAQMD 2016e and staff analysis.

Normal or steady-state operations describe operation for the AEC SCGT when the CTGS and SCR/CO catalysts are functioning. NOx is controlled to 2.5 ppmvd, CO to 2.0 ppmvd, and VOC to 2.0 ppmvd at 15 percent oxygen. The PDOC and PSA required CO emissions from the SCGT to be controlled to 4.0 ppmvd. The CO BACT analysis for CO for the SCGT has been updated in the FDOC and FSA. AES confirmed the startup/shutdown rates for CO would not be affected by the reduction in the BACT level for CO from 4 ppmvd to 2 ppmvd (see additional BACT discussion in the Compliance with LORS section). Emission rates for criteria pollutants vary depending on the operational profile of the equipment. The applicant provided estimated emission rates for 11 cases of turbine operation over various loads, and temperatures in the SAFC. An additional 3 cases were provided to the SCAQMD and are included in the SCAQMD FDOC. This information was used to assess maximum emissions using worst-case assumptions. The maximum hourly emission rates for steady-state operations for the AEC SCGT not including startup or shutdown emissions are based on Case 1 and are included in **Air Quality Table 24**.

Air Quality Table 24
Maximum Simple-Cycle Hourly Steady-State Emission Rates

Simple-Cycle	Maximum Hourly Steady-State Emission Rates[a]					
	NOx	CO	VOC	SOx[b]	PM10/2.5	NH_3
Controlled (ppmvd)	2.5 (1-hour)	4 (1-hour)	2 (1-hour)	N/A	N/A	5
Emission Rates (lb/hr)	8.23	4.01	2.30	1.62	6.23	6.09

Source: CH2 2016s, CH2 2016ii, SCAQMD 2016e
Note: [a] Based on ambient temperature of 28°F and excluded start-up and shutdown
[b] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

The expected maximum daily, monthly, and annual emissions for the AEC SCGT were determined factoring in potential startup and shutdown events with steady-state operation. The operating profiles used to determine the emission rates and emissions from these operating periods are included in **Air Quality Table 25**.

Air Quality Table 25
Simple-Cycle Operating Profile

Simple-Cycle Operating Parameters	Events	Hours
Daily		
Startup	2	1
Shutdown	2	0.4[a]
Steady-State	--	22.6
Total Daily	--	24
Monthly		
Startup	62	31
Shutdown	62	13.4
Steady-State	--	700
Total Monthly	--	744
Annual		
Startup	500	250
Shutdown	500	108
Steady-State	--	2,000
Total Annually	--	2,358

Source: CH2 2016s, SCAQMD 2016e and staff analysis.
Note: [a] Calculated: 2 events * 13 min / 60 min/hr
[b] Calculated: 62 events * 13 min / 60 min/hr

The expected natural gas use and emissions for the AEC SCGT are included below in the Total Facility subsection.

Auxiliary Boiler

Startup events for auxiliary boiler include three classifications: cold, warm and hot. The air quality conditions of certification includes proposed definitions for these classifications. The events are currently described as follows:

- **Cold Start Event:** The auxiliary boiler is at ambient temperature at the time of startup. These conditions are expected to occur if the equipment has been non-operational for 48 hours. It can take up to 170 minutes from fuel initiation for the equipment to reach a base load operating rate.
- **Warm Start Event:** The auxiliary boiler has been non-operational between 10 and 48 hours. It can take up to 85 minutes from fuel initiation for the equipment to reach a base load operating rate.
- **Hot Start Event:** The auxiliary boiler has been non-operational up to10 hours. It can take up to 25 minutes from fuel initiation for the equipment to reach a base load operating rate.

A shutdown for the auxiliary boiler is almost instantaneous and therefore a shutdown scenario for the boiler does not need to be developed. The auxiliary boiler emission rates for startup events are summarized in **Air Quality Table 26**.

Air Quality Table 26
Auxiliary Boiler Startup Emission Rates

Auxiliary Boiler Event Description	Event Duration	Emissions (lbs/event) and (lbs/hour)				
		NOx	CO	VOC	SOx	PM10/2.5
Cold Startup (lbs/event) Cold Startup (lbs/hour)	170 min	4.22 1.49	4.34 1.53	4.69 1.65	0.24 <0.048	0.84 <0.3
Warm Startup (lbs/event) Warm Startup (lbs/hour)	85 min	2.11 1.49	2.17 1.53	2.34 1.65	0.12 <0.048	0.42 <0.3
Hot Startup (lbs/event) Hot Startup (lbs/hour)	25 min	0.62 0.87	0.64 2.29	0.69 0.96	0.035 <0.048	0.12 <0.3

Source: CH2 2016s, CH2 2016ii, SCAQMD 2016e and staff analysis.

Normal or steady-state operation emission factors for auxiliary boilers are not as heavily influenced by external parameters such as weather as compared to the AEC CCGT and SCGT. The original auxiliary boiler operational emission rates proposed were based on the maximum heat input rating of 70.8 MMBtu/hr. In emails dated 1/7/2016 and 4/6/2016, AES requests to SCAQMD to permit the boiler at a reduced operating emission rate. Per an email to SCAQMD dated 4/6/2016, AES requested a monthly heat input limit. The SCAQMD calculated the hourly emissions rate based on the boiler at 21.23 MMBtu/hr corresponding to operation at approximately 30 percent load (modeling was performed at maximum impacts). The revised SAFC submitted to the Energy Commission on 4/12/2016 included hourly emission rates based on the maximum hourly heat input of 70.8 MMBtu/hr. **Air Quality Table 27** includes the proposed auxiliary boiler parameters.

Air Quality Table 27
Maximum Auxiliary Boiler Hourly Steady-State Emission Rates

Auxiliary-Boiler	Maximum Hourly Steady-State Emission Rates				
	NOx	CO	VOC	SOx[a]	PM10/2.5
Controlled	5 ppmv	50 ppmv	0.0052 lb/MMBtu	0.0020 lb/MMBtu	0.0072 lb/MMBtu
AEC Emission Rates (lb/hr)	0.42	2.83	0.47	0.14	0.51
SCAQMD Emission Rate (lb/hr)	0.13	0.80	0.11	0.042	0.15

Source: CH2 2016s and staff analysis.
Note: [a] Based upon 0.75 gr/100 scf; worst case, short-term sulfur content of natural gas.

The proposed maximum daily, monthly, and annual emissions for the auxiliary boiler were determined factoring in potential startup and shutdown events with steady-state operation. Proposed daily, monthly and annual emissions are calculated based on the proposed monthly operating profile included in **Air Quality Table 28**. The daily emissions were calculated by dividing the proposed monthly emissions by an assumed thirty days per month and the annual emissions are based of the monthly multiplied by an assumed 12 months per year.

Air Quality Table 28
Auxiliary Boiler Operating Profile

Auxiliary Boiler Operating Parameters	Events	Hours
Monthly		
Cold Startup	2	2.83
Warm Startup	4	1.42
Hot Startup	4	0.42
Steady-State	--	730.98
Total Monthly[a]	--	744

Source: CH2 2016s, SCAQMD 2016e and staff analysis.
[a] Total monthly hours is the total of the events times the expected duration hours

The expected natural gas use and emissions for the auxiliary boiler are included below in the Total Facility subsection.

Oil/Water Separators

Two 5,000 gallon oil/water separators would be utilized to collect equipment wash water and rainfall. The wash water and rainfall would be contaminated with lubricating oils and grease from the equipment which could be a source of VOCs. An emission factor of 0.000018 pound of VOC per 1000 gallons of wastewater was derived by the SCAQMD based on the U.S. EPA Compilation of Air Pollutant Emission Factors Section 5.1, Table 5.1-3 Fugitive Emission Factors for Petroleum Refineries adjusted according to the vapor pressure of the turbine lubricant. The oil/water separators associated with the AEC CCGT and AEC SCGT would collect from a total containment area of 106,000 square feet and 16,117 square feet respectively. An annual average precipitation in Long Beach of 13 inches was used as the worst case maximum monthly precipitation to determine the maximum monthly volume of waste water. The calculated oil/water separator emissions are summarized in **Air Quality Table 29**.

Air Quality Table 29
Oil/Water Separator Emissions

Equipment and Duration	Oil/Water Separator	
	Maximum Volume (gallons)	VOC (pounds)
AEC CCGT Separator 30-day average	26,958	0.0005
AEC CCGT Separator Monthly	808,737.6	0.015
AEC CCGT Separator Annual	9,704,851	0.18
AEC SCGT Separator 30-day average	4,114	0.00007
AEC SCGT Separator Monthly	122,966	0.0022
AEC SCGT Separator Annual	1,481,088	0.0264
AEC Oil / Water Separators Annual Total	------	0.2064

Source: SCAQMD 2016e and staff analysis.

Total Facility

Air Quality Table 30 presents the expected maximum fuel use for normal operation (excluding commissioning), for each combustion emissions source and the expected facility total based on manufacturer's equipment data and the operating profiles presented in each equipment section. Case 1 conditions are used to determine the expected hourly, daily and monthly fuel usage. Case 4 (65.3 degrees Fahrenheit, maximum load, inlet air cooling) conditions are used to determine the expected annual fuel usage. Case 4 is used for annual calculations because the parameters are based on a temperature considered more representative of annual conditions expected at the AEC site.

Air Quality Table 30
Estimated AEC Equipment Fuel Use

Equipment	Hourly Usage	Daily Usage	Monthly Usage	Annual Usage
AEC CCGT (MMBtu per unit)[a]	2,275	54,604	1,692,600	10,440,000
AEC CCGT (mmscf/hr per unit)[b]	2.2	52	1,612	9,943
AEC CCGT (total MMBtu)[c]	4,550	109,208	3,385,200	20,880,000
AEC SCGT (MMBtu per unit)[a]	879	21,096	653,976	2,065,608
AEC SCGT (mmscf/hr per unit)[b]	0.8	20	622.83	1,967
AEC SCGT (total MMBtu)[d]	3,516	84,384	2,615,904	8,262,432
Auxiliary Boiler (MMBtu)[e]	70.8	535	16,057	189,120
Facility Total	8,137	194,127	6,017,161	29,326,924

Source: CH2 2016s, CH2 2016aa, CH2 2016bb, SCAQMD 2016e and staff analysis.
Note:[a] Hourly, daily and monthly usage based upon Case 1 conditions. Annual usage based on Case 4 conditions.
[b] Based on fuel BTU content of 1050 MMBtu/mmscf
[c] Based on two CCGTs
[d] Based on four SCGTs
[e] Hourly and daily based on maximum heat input. Monthly and annual based on reduced load corresponding to approximately 21.23 MMBtu/hr

Air Quality Table 31 includes estimated operational emissions for routine operation for the proposed AEC. The emissions are calculated based on the equipment emission rates and operating profiles for each emission unit.

Air Quality Table 31
Estimated Aec Total Operational Emissions

Project Component	Total Emissions				
	NOx	CO	VOC	SOx[a]	PM10/2.5
	Maximum Daily Operations (lbs/day)				
AEC CCGT	488.50	1,074.13.00	256.75	116.64	204.00
AEC SCGT	225.11	177.47	63.61	38.89	149.49
Auxiliary Boiler[a]	10.88	69.62	12.17	3.54	12.46
Auxiliary Boiler[b] (30-day)	3.81	20.16	3.4	1.06	3.78
Equipment Total[a]	1,888	2,928	780	392	1,018
Equipment Total[b]	1,881	2,878	771	390	1,010

Project Component	Total Emissions				
	NOx	CO	VOC	SOx[a]	PM10/2.5
	Maximum Monthly Operations (lbs/month)				
AEC CCGT	13,463.25	24,638.99	7577.38	3,615.84	6,324.00
AEC SCGT	6,983.64	5,504	1,973.32	1,206.55	4,638.14
Auxiliary Boiler[a]	114.39	604.70	101.91	31.8	113.49
Auxiliary Boiler[b]	326.37	2,088.59	365.06	106.18	373.90
AEC CCGT Separator	----	----	0.015	----	----
AEC SCGT Separator	----	----	0.0022		----
Equipment Total[a]	55,187	71,899	23,413	12,164	31,574
Equipment Total[b]	54,975	73,383	23,150	12,090	31,314
	Maximum Monthly Operation (tons/month)				
Equipment Total[a]	27.49	35.95	11.57	6.04	15.66
Equipment Total[b]	27.59	36.69	11.71	6.08	15.79
	Maximum Annual Operation (lbs/year)				
AEC CCGT	83,850	180,544	52,668	7,435	39,440
AEC SCGT	26,260	29,730	7,510	1,275	14,695
Auxiliary Boiler	1,350.8	7,256	1.223	382	1,362
AEC CCGT Separator	----	----	0.18	----	----
AEC SCGT Separator	----	----	0.0264		----
	Maximum Annual Operation (tons/year)				
AEC CCGT	41.93	90.27	26.33	3.72	19.72
AEC SCGT	13.13	14.87	3.76	0.64	7.35
Auxiliary Boiler	0.68	3.63	0.61	0.19	0.68
AEC CCGT Separator	----	----	0.00009	----	----
AEC SCGT Separator	----	----	0.000013		----
	Maximum Combined Equipment Annual Operation (tons/year)				
AEC CCGTs (total)	83.86	180.54	52.66	7.44	39.44
AEC SCGTs (total)	52.52	59.48	15.04	2.56	29.39
Auxiliary Boiler	0.68	3.63	0.61	0.19	0.68
Oil/Water Separators	----	----	0.000103	----	----
Total Facility	137	244	68	10	70

Source: CH2 2016s, CH2 2016aa, CH2 2016bb, SCAQMD 2016e and staff analysis.
Notes: [a] Emissions Includes two CCGTS and four SCGTs. Based on maximum auxiliary boiler heat input.
[b] Emissions Includes two CCGTS and four SCGTs. Based on auxiliary boiler reduced heat input used by SCAQMD

The maximum commissioning year emissions are included in **Air Quality Table 32.** Maximum commissioning year emissions calculated by adding the total emissions from commissioning to the remaining maximum normal operating emissions for the remaining timeframe. For example, the commissioning of the AEC CCGT is expected to take 6 months. The commissioning year emissions would include emissions from the commissioning period and 6 months of routing operation emissions. Maximum commissioning year emissions are used to determine the first year RECLAIM requirements. Since the auxiliary boiler would have a minimal commissioning period, maximum annual emissions are used for the auxiliary boiler commissioning year emissions.

Air Quality Table 32
Maximum Annual Emissions, Commissioning Year

	Commissioning Year Emissions (lbs/year)				
Project Component	**NOx**	**CO**	**VOC**	**SOx**	**PM10/2.5**
AEC CCGT	108,377	249,162	60,146	26,536	46,410
AEC SCGT	68,575	74,931	18,596	11,31243,4	43,487
Auxiliary Boiler	1,351	7,256	1,223	382	1,362

Source: SCAQMD 2016e

Ammonia Emissions

Ammonia (NH_3) is injected into the flue gas stream as part of the SCR system that controls NOx emissions. In the presence of the catalyst, the ammonia and NOx react to form harmless elemental nitrogen and water vapor. However, not all of the ammonia reacts with the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered from the stacks. These ammonia emissions are known as ammonia slip.

Per BACT, SCAQMD requires a maximum ammonia slip rate of 5 ppmvd at 15 percent oxygen for the proposed turbines and 5 ppmvd at 3 percent oxygen for the auxiliary boiler. The expected ammonia emissions from the SCR/CO oxidation catalyst systems are included in **Air Quality Table 33.** For the AEC CCGT and AEC SCGT, Case 1 was used in conjunction with the 5 ppm NH_3 BACT limit to calculate a maximum hourly ammonia emission rate. The annual emission rate is based off of Case 4 and the AEC CCGT operating profile in **Air Quality Table 22**. The maximum hourly emission rate for the auxiliary boiler assumed the boiler operated at maximum heat input. The auxiliary boiler annual and annual hourly rate assumes the load reduction operating profile used by the SCAQMD.

Air Quality Table 33
Estimated AEC Equipment Ammonia Emissions

Equipment	**Maximum Hourly Rate (lbs/hr)**	**Annual Hourly Rate (lbs/hr)**	**Maximum Annual (lbs/year)**	**Maximum Annual (ton/year)**
AEC CCGT[a]	15.7	15.1	70,004	35.0
AEC SCGT[a]	6.09	6.07	14,313	7.16
Auxiliary Boiler[b]	0.16	0.05	423	0.22
Total Equipment[c]	---	----	197,683	98.86

Source: SCAQMD 2016e and staff analysis.
Note: [a] Maximum hourly is based on Case 1, Max hourly based on Case 4
[b] Max hourly is based on maximum heat input. Annual hourly is based on reduced load.
[C] Total Equipment consists of two CCGTs, four SCGTs and one auxiliary boiler

The project owner expects the ammonia slip rate from the SCRs of the of the GE 7FA.05 combined-cycle turbines, the GE LMS-100PB simple-cycle turbines, and the auxiliary boiler would not exceed the 5.0 ppmvd limit. Energy Commission staff notes that control systems can be operated and maintained to routinely achieve less than 5.0 ppmvd, as established in the Guidance for Power Plant Siting (ARB 1999). The SCAQMD FDOC includes proposed permit conditions establishing a 5 ppmvd emissions limit for ammonia on the proposed turbines and the auxiliary boiler. These conditions would be incorporated into the conditions of certification.

The proposed AEC includes two 40,000 gallon storage tanks. No ammonia emissions are expected from the tanks because the filling losses will be controlled by a vapor return line and the breathing losses by a 50 psig pressure valve.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Potential impacts from the AEC result from the proposed construction, initial, commissioning, and normal operation phases, and cumulative effects. The cumulative impacts analysis assesses impacts that result from the proposed project's incremental effect combined with other emission sources. The project's incremental effect is viewed over time with other closely related past, present, and reasonably foreseeable future projects whose impacts may compound or increase the incremental effect of the proposed project. (Pub. Resources Code § 21083; Cal. Code Regs., tit. 14, §§ 15064(h), 15065I, 15130, and 15355). Additionally, cumulative impacts are assessed in terms of conformance with the District's attainment or maintenance plans.

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

Staff characterizes air quality impacts as follows: All project emissions of nonattainment criteria pollutants and their precursors (NOx, VOC, PM10, PM2.5, and SOx) are considered significant and must be mitigated. For short-term construction activities that essentially cease before operation of the power plant, our assessment is qualitative and mitigation consists of controlling construction equipment tailpipe emissions and fugitive dust emissions to the maximum extent feasible. For operating emissions, mitigation includes both the Best Available Control Technology (BACT) and emission reduction credits (ERC) or other valid emission reductions to mitigate emissions of both nonattainment criteria pollutants and their precursors.

The ambient air quality standards used by staff as the basis for characterizing project impacts are health-based standards established by the ARB and U.S. EPA. They are set at levels that contain a margin of safety to adequately protect the health of all people, including those most sensitive to adverse air quality impacts such as the elderly, persons with existing illnesses, children, and infants.

DIRECT/INDIRECT IMPACTS AND MITIGATION

Ambient air quality impacts occur when project emissions cause the ambient concentration of a pollutant to increase. The proposed project emits pollutants on a mass basis. Project-related emissions are the actual mass of emitted pollutants, which are dispersed in the atmosphere before reaching the ground. Impacts refer to the concentration of any pollutant that reaches the ground level. An impact analysis includes quantifying the emissions released from the proposed equipment and the use of an atmospheric dispersion model to determine the probable impact at ground level. The analysis focuses on the predicted change to the ground level impact due to the additional emissions from the proposed project.

Air dispersion models provide a means of predicting the location and ground level magnitude of the impacts of a new emissions source. These models consist of several complex series of mathematical equations, which are repeatedly calculated by a computer for many ambient conditions to provide theoretical maximum offsite pollutant concentrations for short-term (one-hour, three-hour, eight-hour, and 24-hour) and annual periods. The model results are generally described as maximum concentrations, often described as a unit of mass per volume of air, such as micrograms per cubic meter ($\mu g/m^3$).

The project owner conducted air dispersion modeling based on guidance presented in the *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) and the American Meteorological Society/Environmental Protection Agency Regulatory Model known as AERMOD (version 15181). The U.S. EPA designates AERMOD as a “preferred” model for refined modeling in all types of terrain. AERMOD considers emissions in the context of various ambient meteorological conditions, local terrain and nearby structures that could affect air flow.

The inputs for the air dispersion models include stack information (exhaust flow rate, temperature, and stack dimensions), specific turbine emission data and meteorological data, such as wind speed and atmospheric conditions, and site elevation. For the proposed AEC, the meteorological data collected at the North Long Beach site was selected for the modeling because the station is the closest to the proposed site, there is no complex terrain between the station and the proposed site, and the land uses surrounding the monitoring site and AEC are similar. Specifically both are surrounded by a mix of low, medium and high intensity land use and have open water within 10 miles to the south-southwest.

North Long Beach station meteorological data was compiled by the SCAQMD for the dispersion modeling analysis. The compiled data includes years 2006 through 2009 and 2011. Data from 2010 was not recommended by the SCAMQD due to incompleteness. In addition 2012 data was not recommended due to suspicious wind speed. The complied data was provided by the SCAQMD to the project owner to be processed through AERMET.

U.S. EPA approved NO_2 to NOx conversion ratios of 0.80 and 0.75 are assumed for evaluating 1-hour and annual NO_2 impacts from the project respectively. The base modeling receptor grid for AERMOD modeled impacts consists of receptors placed at the project's property boundary and Cartesian-grid receptors that are placed beyond the Project's site boundary at spacing that increases with distance from the origin. An additional receptor was placed at the charter school located at the proposed AEC site.

Project-related modeled concentrations are added to the highest background concentrations to determine the total impact of the project. This is a conservative approach because it assumes the highest project impacts occur concurrently with the worst case background concentrations. Staff revised the background concentrations provided by the project owner where necessary to reflect the most recent worst case background values. The background values used by staff are the values in **Air Quality Table 12**. Staff combined the project owner modeled impacts with the appropriate background concentrations, and compares the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new exceedance of the ambient air quality standards or would contribute to an existing exceedance.

The modeling analysis included higher stack exit concentrations of CO originally proposed in the PDOC and PSA. The BACT levels reviewed for CO in the FDOC and FSA are lower. The normal BACT operating rate for CO decreased from 2.0 ppmvd at 15 percent oxygen to 1.5 ppmvd at 15 percent oxygen for the combined-cycle turbines and from 4.0 ppmvd to 2.0 ppmvd for the simple-cycle turbines. The decrease in the CO operating rate did not require the project to be remodeled since the final CO emission levels were lower than the levels previously modeled. The projects emissions did not exceed any CAAQS or NAAQS with the higher emission rate. Therefore, exceedances are not expected with lower emission rates.

CONSTRUCTION IMPACTS

The AEC short-term construction ambient air quality impacts were estimated by the project owner. The maximum construction emission estimates are associated with the construction of Power Block 1, or the AEC CCGT. This activity is expected to last approximately 34 months and will occur while the existing AGS is in operation. In order to accurately capture the impacts of the construction while the existing AGS boilers are in operation, overlap scenarios were developed and modeled. The modeled overlap scenario including AEC CCGT is described as follows:

- **Overlap Scenario 1**: AEC CCGT construction with simultaneous operation of the existing AGS Units 1-6.

The construction of the two power blocks will occur at different time periods. The construction of the SGCT is expected to occur between May 2020 and August 2021. During this time period the AEC CCGT is expected to be in operation. AEC developed a second overlap scenario capture the impacts of the operation of the AEC CCGT while the AEC SCGT is undergoing construction. In addition, AEC included the potential overlap of the operation of the existing AGS boilers 3, 4, and 6. Originally AES proposed AGS boilers 1, 2, and 5 would be retired once the AEC CCGT commences operation and were therefore not included. In addition, originally, existing AGS Units 3, 4, and 6 were scheduled for retirement prior to the expected completion of the AEC SCGT.

- **Overlap Scenario 2**: AEC SCGT construction with the simultaneous operation of the AEC CCGT and existing AGS Units 3, 4 and 6

The modeled impacts from these overlap scenarios are included in the Overlap Impacts Analysis section and included in the Operation Impacts and Mitigation section after Visibility Impacts. In addition the construction mitigation discussion will be included following the overlap impacts discussion. On October 26, 2016, AES requested Unit 6 be retired instead of Unit 5. The SCAQMD accepted this change since both Unit 5 and Unit 6 are identical units. Units 5 and 6 are permitted with identical potentials to emit through the SCAQMD. Recent actual emissions from Units 5 and 6 are presented in the SCAQMD FDOC. According to SCAQMD records, actual emissions from 2013 for Unit 5 were higher than Unit 6 whereas actual emissions from 2014 for Unit 5 were lower than Unit 6. Regardless of the historical operating profile, Units 5 and 6 are identical in size and close to one another and therefore any future operation would be expected to be equivalent. Therefore the modeling scenarios are still representative of potential overlap and do not need to be reanalyzed.

OPERATION IMPACTS AND MITIGATION

The following section discusses the project's direct and cumulative ambient air quality impacts, as estimated by the project owner and subsequently evaluated by staff. The facility owner performed a number of direct impact modeling analyses for routine operations including start up and shutdown scenarios, shoreline fumigation and inversion break-up, commissioning activities, and whole facility overlap scenarios.

<u>Routine Operation Impacts</u>

Emissions and operating parameters exhibit variation with ambient temperature and operating load. To determine the worst case air quality impacts a dispersion modeling analysis was conducted at three load scenarios and at three different temperature. The load scenarios are minimum (45 percent for AEC CCGT and 50 percent for AEC SCGT), average (75 percent) and full load (100 percent) and ambient temperatures are 28, 65.3, and 107 degrees Fahrenheit. Source parameters were provided by the manufacturer for the different scenarios.

The modeling assessment for the AEC CCGT included the following assumptions and conditions for normal operation and startup/shutdown scenarios:

- The maximum 1-hour impacts assumed that both GE Frame 7FA.05 units were in start-up mode.

- The 3-hour SO_2 impacts assumed both GE Frame 7FA.05 units were in continuous average load operation.
- The 1-, 3-, and 24-hour SO_2 emission rates were based off a fuel sulfur concentration of 0.75 grain of sulfur per 100 dscf of natural gas.
- The 8-hour CO emission rates were based on two cold starts, two shutdowns and the balance in steady-state operation.
- .The 24-hour PM10 and PM2.5 emission rates used 8.5 pounds per hour for each modeling scenario.
- The annual emission rates were based on 4,100 hours of steady-state operation, 80 cold startups 88 warm startups and 332 hot startups and 500 shutdowns.
- The stack heights would all be 42.7 meters with 6.10 meter diameters.

Air Quality Table 34 includes the AEC CCGT operating assumptions used in the modeling analysis.

Air Quality Table 34
Modeled Scenarios for the Combined-Cycle Gas Turbines

Pollutant	Averaging Period	Operating Case Scenario	Operating Load	Emission Rate (lbs/hr)
NO_2	1 hour	Case 3	Minimum	61
	1 hour NAAQS	Case 3	Minimum	61
	Annual	Case 7	Minimum	6.24
CO	1 hour	Case 3	Minimum	325
	8 hour	Case 3	Minimum	118
PM10	24 hour	Case 7	Minimum	8.5
	Annual	Case 7	Minimum	4.5
PM2.5	24 hour	Case 7	Minimum	8.5
	Annual	Case 7	Minimum	4.5
SO_2	1 hour	Case 2	Average	3.84
	1 hour NAAQS	Case 6	Average	3.72
	3 hour NAAQS	Case 6	Average	3.72
	24 hour	Case 6	Average	3.72

Source: CH2 2016s, Table 5.1 -31,

The modeling assessment for the AEC SCGT included the following assumptions and conditions for normal operation and startup/shutdown scenarios:

- The maximum 1-hour impacts assumed that all four GE LMS-100PB were in start-up mode and included one startup, one shutdown, and the balance of the hour in steady-state operation.
- The 1-, 3-, and 24-hour SO_2 emission rates were based on a fuel sulfur concentration of 0.75 grain of sulfur per 100 dscf of natural gas.
- The 8-hour CO emission rates were based on two starts, two shutdowns and the balance in steady-state operation.

- .The 24-hour PM10 and PM2.5 emission rates used 6.23 pounds per hour for each modeling scenario.
- The annual emission rates were based on 2,000 hours of steady-state operation, 500 startups and 500 shutdowns.
- The stack heights would all be 24.4 meters with 4.11 meter diameters.

Air Quality Table 35 includes the AEC SCGT operating assumptions used in the modeling analysis.

Air Quality Table 35
Modeled Scenarios for the Simple-Cycle Gas Turbines

Pollutant	Averaging Period	Operating Case Scenario	Operating Load	Emission Rate (lbs/hr)
NO_2	1 hour	Case 3	Minimum	21.2
	1 hour NAAQS	Case 3	Minimum	21.2
	Annual	Case 7	Minimum	2.29
CO	1 hour	Case 3	Minimum	44.9
	8 hour	Case 3	Minimum	15
PM10	24 hour	Case 7	Minimum	6.23
	Annual	Case 7	Minimum	1.68
PM2.5	24 hour	Case 7	Minimum	6.23
	Annual	Case 7	Minimum	1.68
SO_2	1 hour	Case 1	Maximum	1.62
	1 hour NAAQS	Case 5	Maximum	1.61
	3 hour NAAQS	Case 5	Maximum	1.61
	24 hour	Case 5	Maximum	1.61

Source: CH2 2016s, Table 5.1 -31,

The modeling assessment for the auxiliary boiler included the following assumptions and conditions for normal operation and startup/shutdown scenarios:

- The maximum 1- and 3-hour impacts were based on the maximum hourly firing rates, excluding startup and shutdown.
- The 1-, 3-, and 24-hour SO_2 emission rates were based off a fuel sulfur concentration of 0.75 grain of sulfur per 100 dscf of natural gas.
- The 8-hour CO emission rates were based on one cold startup and the balance in steady-state operation.
- The 24-hour emission rates were based on 30-day average monthly emissions rates including a heat input of 16,055 MMBtu, 2 cold startups, 4 warm startups and 4 hot startups.
- The annual emission rates were based on a heat input of 189,155 MMBtu, 24 cold startups, 48 warm startups and 48 hot startups.
- The stack height would be 24.4 meters and the exhaust temperature would be 318 degrees Fahrenheit.

Air Quality Table 36 includes the auxiliary boiler emission rates used for the modeling analysis.

Air Quality Table 36
Modeled Emission Rates for the Auxiliary Boiler

Pollutant	Averaging Period	Emission Rate (lbs/hr)
NO_2	1 hour	0.42
	1 hour NAAQS	0.42
	Annual	0.15
CO	1 hour	2.83
	8 hour	2.37
PM10	24 hour	0.16
	Annual	0.15
PM2.5	24 hour	0.16
	Annual	0.15
SO_2	1 hour	0.14
	1 hour NAAQS	0.14
	3 hour NAAQS	0.14
	24 hour	0.046

Source: CH2 2016s, Table 5.1 -31

Air Quality Table 37 summarizes the predicted maximum ground-level concentrations for criteria pollutants and the corresponding averaging period. The table includes background values and compares the total impact to the limiting AAQS. The values shown in bold indicated an exceedance of an air quality standard.

Air Quality Table 37
Proposed AEC Routine Operations Impacts

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)[a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1 hour	31.3	256	287	339	85%
	1 hour NAAQS	22.6	146	169	188	90%
	Annual	0.20	48	48	57	84%
PM10	24 hour	1.71	**59**	**61**	50	**121%**
	Annual	0.19	**27.3**	**27.49**	20	**137%**
PM2.5	24 hour	1.25	27.2	28.45	35	81%
	Annual	0.19	10.97	11.16	12	93%
CO	1 hour	186	3,665	3851	23,000	17%
	8 hour	44.3	2,978	3022	10,000	30%
SO_2	1 hour	2.12	58	60	655	9%
	1 hour NAAQS	1.59	31	32	196	16%
	3 hour NAAQS	1.69	58	60	1,300	5%
	24 hour	0.53	11	11	105	11%

Source: CH2 2016s Table 5.1 -38 and staff analysis.
[a] Background values are adjusted as presented in **Air Quality Table 12**

Air Quality Table 37 demonstrates that the project would not cause a significant impact except for 24-hour and annual PM10 emissions. Routine Operation Impacts could contribute to existing violations of annual PM10 ambient air quality standards. The impacts of PM2.5 are close to the most stringent standards due to the existing high background concentrations, but the routine project impacts would not create new violations.

The direct impacts of CO and SO_2 would not be significant because routine operation of the project would neither cause nor contribute to a violation of these standards. Mitigation for emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing impacts to PM10, PM2.5, and ozone.

Fumigation Impacts Fumigation Modeling Impact Analysis

There is the potential that higher short-term concentrations of pollutants may occur during fumigation conditions. During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air would also be vertically mixed, bringing some of those emissions down to the ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning pollution event, called fumigation, usually lasts approximately 30 to 90 minutes.

Fumigation conditions are short-duration events and are generally only compared to one-hour standards. Two types of fumigation are analyzed using the SCREEN3 model: inversion breakup and shoreline. Inversion breakup fumigation occurs under low-wind conditions when a rising morning mixing height caps a stack (i.e., is at or right above the stack height) limiting plume rise and mixing, which fumigates the air below. Shoreline fumigation occurs near a large water body shoreline when both a roughness boundary and more dominant thermal boundary cause turbulent dispersion to be much more enhanced near the ground, fumigating air below.

The project owner completed a fumigation analysis using the U.S. EPA AERSCREEN (Version 15181) model. The analysis considered operating scenarios and loads included in the Routine Operation Analysis previously discussed using regulatory default mixing heights.

The SAFC analysis assumed all emission sources were located 2,960 meters from the shoreline. The combined-cycle and simple-cycle turbine stacks are expected to be located more than 3,000 meters away from the shoreline. The auxiliary boiler however is expected to be located 2,960 meters away from the shoreline. Fumigation events are short term meteorological events. Therefore, only short term averaging periods are considered. Federal NO_2 and SO_2 standards are not evaluated because of the long term averaging periods associated with those standards. Total project impacts were determined by adding the modeled impacts from the combined-cycle turbines, simple-cycle turbines and the auxiliary boiler.

The revised analysis indicated the combustion sources were too far away from the shoreline to result in shoreline fumigation occurrences. Shoreline fumigation was not calculated by AERSCREEN because the plume height was below the thermal internal boundary layer height for the distance to the shoreline. The results of the revised inversion break-up impacts analysis combined with background concentrations are included in **Air Quality Table 38.**

Air Quality Table 38
Maximum Revised Inversion Break-Up Impacts, (µg/m^3)

Pollutant	Averaging Period	Project Impact (µg/m^3)	Background (µg/m^3) [a]	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Percent of Standard
NO_2	1 hour[b]	69.4	256	325	339	96%
CO	1 hour	414	3,665	4079	23,000	18%
	8 hour	138	2,978	3116	10,000	31%
SO_2	1 hour	4.9	58	63	655	10%
	3 hour	4.9	58	63	1,300	5%

Source: SCAQMD 2016e Table 50A and staff analysis.
[a] Background values are adjusted, based on staff analysis as presented in **Air Quality Table 12**.
[b] Includes an ambient NO_2 to NOx conversion ratio of 0.80

The maximum inversion break-up impacts combined with background values are below the applicable AAQS and therefore no further analysis is necessary.

Commissioning-Phase Impacts

Plant commissioning impacts from the AEC CCGT and AEC SCGT would occur during two separate periods. Each commissioning event would only occur over a short-term period. A dispersion analysis was provided by AES for both the AEC CCGT and AEC SCGT commissioning events.

The commissioning period for the AEC CCGT is expected to last 6 months. Commissioning activities for the combined-cycle turbines are expected to occur over approximately 1,992 operating hours total for both combustion turbines (996 hours per combustion turbine). The AERMOD dispersion analysis for Power Block 1 assumed both turbines would be simultaneously commissioned. The maximum impact would occur if both turbines were undergoing commissioning activities with the highest unabated emissions. For the AEC CCGT this corresponds to CTG Testing (Full Speed No Load).

The short term concentrations impacts from the commissioning phase were combined with ambient background concentrations and compared to the short-term AAQS. Emission rates of PM10, PM2.5 and SO_2 are generally expected to be equal or lower than normal operating rates during the commissioning phase due to reduced commissioning loads however lower operating loads can result in slightly elevated impacts. Annual impacts were also evaluated for during the commissioning year using the six month commissioning emissions and six months of normal operation. All commissioning scenarios included impacts from the steady state operation of the auxiliary boiler.

The federal 1-hour NO_2 and SO_2 standards are expressed as a 3-year average of the 98th and 99th percentile of the daily maximum 1-hour concentration respectively. Since these are statistically based standards, it is not applicable to the short-duration commissioning phase. Staff does not expect significant impacts due to the very limited commissioning period compared to the 3-year averaging time used for these standards.

Air Quality Table 39 includes the results of the AEC CCGT commissioning phase impact analysis. The predicted impacts from the PM10 emissions, highlighted in bold font, are above the CAAQS. However the PM10 background concentrations are above the CAAQS without taking into account an incremental contribution from the proposed AEC. Therefore the commissioning of the GE 7FA.05 combined-cycle turbines would contribute to existing violations of annual PM10 ambient air quality standard. The impacts from PM2.5 and NO_2 are close to the most stringent standards due to the existing high background concentrations, but would not create new violations.

Air Quality Table 39
Proposed Combined-Cycle Commissioning Impacts, ($\mu g/m^3$)[a]

Pollutant	Averaging Period	Project Impact[a] ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total[b] Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2[c]	1 hour	67.6	256	323.6	339	95%
	Annual	0.26	48	48	57	85%
PM10	24 hour	1.62	**59**	**61**	50	**121%**
	Annual	0.21	**27.3**	**27.5**	20	**138%**
PM2.5	24 hour[d]	1.14	27.2	28.3	35	81%
	Annual	0.21	10.97	11.18	12	93%
CO	1 hour	1,231	3,665	4,896	23,000	21%
	8 hour	835	2,978	3,813	10,000	38%
SO_2	1 hour	2.24	58	60	655	9%
	3 hour	1.92	58	60	1,300	5%
	24 hour	0.55	11	12	105	11%

Source: CH2 2016s and staff analysis
Notes:
[a] Includes impacts from commissioning of two GE Frame 7FA.05 turbines and normal operation of the auxiliary boiler
[b] Modeled concentration plus background values adjusted by staff
[c] NO_2 determined with U.S. EPA Ambient Ratio Method (ARM) based on NO_2/NOx ratio of 0.80 and 0.75 for 1-hour and annual averaging times respectively.
[d] The 24-hour PM2.5 standards is based on 5-year average, high-8th-high modeled concentration

The commissioning period for the four AEC SCGTs is expected to last 90 days. Commissioning activities for the simple-cycle turbines are expected to occur over approximately 1,120 operating hours total for all four combustion turbines (280 hours per combustion turbine). The AERMOD dispersion analysis for Power Block 2 assumed the four CTGs would be simultaneously commissioned while both combined-cycle CTGs were operated in cold start mode. The maximum impact would occur if both turbines were undergoing commissioning activities with the highest unabated emissions. For the AEC SCGT this corresponds to emissions tuning.

The short term concentrations impacts from the commissioning phase were combined with ambient background concentrations and compared to the short-term AAQS. Emission rates of PM10, PM2.5, and SO_2 are generally expected to be equal or lower than normal operating rates. Annual impacts were also evaluated for during the commissioning year using the 90 day commissioning emissions and normal operation emissions for remainder. All commissioning scenarios included impacts from the steady state operation of the auxiliary boiler.

The federal 1-hour NO_2 standard is expressed as a 3-year average of the 98th percentile of the daily maximum 1-hour concentration. Since this is a statistically based standard, it is not applicable to the short-duration commissioning phase. Staff does not expect it to have significant impact due to the very limited commissioning period compared to the 3-year averaging time used for the standard.

Air Quality Table 40 includes the results of the AEC SCGT commissioning phase impact analysis. The predicted impacts from the PM10 emissions, highlighted in bold font, are above the CAAQS. However the PM10 background concentrations are above the CAAQS without taking into account an incremental contribution from the proposed AEC. Therefore the commissioning of the GE LMS-100PB simple-cycle turbines would contribute to existing violations of annual PM10 ambient air quality standard. The impacts from PM2.5 and NO_2 are close to the most stringent standards due to the existing high background concentrations, but would not create new violations.

Air Quality Table 40
Proposed Simple-Cycle Commissioning Impacts, (µg/m^3)[a]

Pollutant	Averaging Period	Project Impact[a] (µg/m^3)	Background (µg/m^3)	Total[b] Impact (µg/m^3)	Limiting Standard (µg/m^3)	Percent of Standard
NO_2[c]	1 hour	61.9	256	317.9	339	94%
	Annual	0.20	48	48	57	85%
PM10	24 hour	1.71	**59**	**61**	50	**121%**
	Annual	0.20	**27.3**	**27.5**	20	**138%**
PM2.5	24 hour[d]	1.25	27.2	28.5	35	81%
	Annual	0.20	10.97	11.17	12	93%
CO	1 hour	470	3,665	4,135	23,000	18%
	8 hour	240	2,978	3,218	10,000	32%
SO_2	1 hour	2.12	58	60	655	9%
	3 hour	1.69	58	60	1,300	5%
	24 hour	0.53	11	12	105	11%

Source: CH2 2016s and staff analysis
Notes:
[a] Includes impacts from commissioning of two GE Frame 7FA.05 turbines and normal operation of the auxiliary boiler
[b] Modeled concentration plus background values adjusted by staff
[c] NO_2 determined with U.S. EPA Ambient Ratio Method (ARM) based on NO_2/NOx ratio of 0.80 and 0.75 for 1-hour and annual averaging times respectively.
[d] The 24-hour PM2.5 standards is based on 5-year average, high-8th-high modeled concentration

Chemically Reactive Pollutant Impacts

The project's gaseous emissions of NOx, SOx, VOC, and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5.

Ozone Impacts

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the modeling to determine ozone impacts. Currently, there are no regulatory agency models approved for assessing single-source ozone impacts although guidance documents are becoming available. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the AEC project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts would be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards.

PM2.5 Impacts

Secondary particulate formation, which is assumed to be 100 percent PM2.5, is the process of conversion from gaseous reactants to particulate products. The process of gas-to-particulate conversion, which occurs downwind from the point of emission, is complex and depends on many factors, including local humidity and the presence of air pollutants. The basic process assumes that the SOx and NOx emissions are converted into sulfuric acid and nitric acid first and then react with ambient ammonia to form sulfate and nitrate. The sulfuric acid reacts with ammonia much faster than nitric acid and converts completely and irreversibly to particulate form. Nitric acid reacts with ammonia to form both a particulate and a gas phase of ammonium nitrate. The particulate phase will tend to fall out; however, the gas phase can revert back to ammonia and nitric acid. Thus, under the right conditions, ammonium nitrate and nitric acid establish a balance of concentrations in the ambient air. There are two conditions that are of interest, described as *ammonia rich* and *ammonia limited*. The term ammonia rich indicates that there is more than enough ammonia to react with all the sulfuric acid and to establish a balance of nitric acid-ammonium nitrate. Further ammonia emissions in this case would not necessarily lead to increases in ambient PM2.5 concentrations. In the case of an ammonia limited environment, there is insufficient ammonia to establish a balance and thus additional ammonia would tend to increase PM2.5 concentrations.

U.S. EPA issued guidance on May 20th, 2014 that requires secondary PM2.5 impacts be addressed for sources seeking PSD permits. This guidance provides several methods, or tiers, that can be used to analyze secondary PM2.5 impacts; including refined air dispersion modeling methods.

Ammonia (NH_3) is a particulate precursor but not a criteria pollutant because there is no ambient air quality standard for ammonia. Reactive with sulfur and nitrogen compounds, ammonia can be found from natural sources, agricultural sources, and as a byproduct of tailpipe controls on motor vehicles and stack controls on power plants.

Energy Commission staff recommends limiting ammonia slip emissions to the maximum extent feasible. This level of control is appropriate for avoiding unnecessary ammonia emissions, consistent with staff policy to reduce emissions of all nonattainment pollutant precursors to the lowest feasible levels.

Visibility Impacts

A visibility analysis for Class II areas within 50 km of the proposed AEC site was performed using VISCREEN per the procedures outlined in the Workbook for Plume Visual Impact Screening and Analysis (EPA 1992). VISCREEN calculates the potential impact of a plume of specified emissions for specific transport and dispersion conditions. Tier I and Tier II assessments were conducted using Class I criterion which is conservative for Class II areas.

Air Quality Table 41 summarizes the VISCREEN results for the Class II areas evaluated.

Air Quality Table 41
Maximum Revised Inversion Break-Up Impacts, (μg/m^3)

Class II Area	Minimum Distance	Maximum Distance	Variable	Sky Result	Terrain Result	Criteria
Crystal Cove State Park	30.3	35.5	Color Difference	1.009	1.893	2.0
			Contrast	0.012	0.016	0.05
Water Canyon/Chino Hills State Park	29.6	42.2	Color Difference	1.393	1.951	2.0
			Contrast	0.016	0.016	0.05
Kenneth Hahn State Park	34.6	37.3	Color Difference	0.815	1.594	2.0
			Contrast	0.01	0.014	0.05

CH2 2016s Table 5.1-42, CH2 2016aa, CH2 2016bb

As shown in **Air Quality Table 41**, the modeled results for sky and terrain are below the Class I area criteria for both color difference and contrast.

Overlap Impact Analysis

Construction activities associated with the AEC would overlap with operation of both the existing AGS boilers and the AEC CCGT. As discussed in the Construction Impacts section, two overlap scenarios were developed for modeling:

- Overlap Scenario 1: AEC CCGT construction with simultaneous operation of existing AGS Units 1-6; and
- Overlap Scenario 2: AEC SCGT construction with simultaneous operation of the AEC CCGT and existing Units 3, 4 and 6.

Air Quality Table 42 summarizes the results of the modeling analysis for the modeled Overlap Scenario 1. The maximum construction short-term and annual emissions rates presented in **Air Quality Table 31** were used in conjunction with the maximum rolling 24-month emissions from 2008 through 2012 from each AGS unit. Staff inquired in Data Request 6, Request 123 why the most recent annual data from the AGS was not used for the overlap modeling and requested the annual AGS data in Data Request 6, Request 122. AEC provided 2013 and 2014 data in Data Response Set 6 (AEC 2015s) which had lower emission rates than those used for the overlap modeling. The total impact is the sum of the existing background condition plus the maximum impact predicted by the modeling analysis for Overlap Scenario 1. The values in **bold** in the Background and Total Impact columns of **Air Quality Table 42** represent the values that either equal or exceed the relevant ambient air quality standard.

Air Quality Table 42
Proposed Maximum Overlap Scenario 1 Impacts, ($\mu g/m^3$)[a]

Pollutant	Averaging Period	Project Impact[a] ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total[b] Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2[c]	1 hour	12.7	256	268	339	79%
	1 hour NAAQS[d]	12.5	146	159	188	85%
	Annual	1.87	48	49	57	87%
PM10	24 hour	7.31	**59**	66	50	**133%**
	Annual	2.08	**27.3**	29.4	20	**147%**
PM2.5	24 hour[d]	1.60	27.2	28.8	35	82%
	Annual	0.67	10.97	11.64	12	97%
CO	1 hour	277	3,665	3942	23,000	17%
	8 hour	183	2,978	3161	10,000	32%
SO_2	1 hour	1.59	58	60	655	9%
	1 hour NAAQS	1.24	31	32	196	16%
	3 hour NAAQS	1.24	58	59	1,300	5%
	24 hour	0.45	11	11	105	11%

Source: CH2 2016s Table 5.1-43 and staff analysis
Notes:
[a] Onsite construction only
[b] Modeled concentration plus background values adjusted by staff
[c] NO_2 determined with U.S. EPA Ambient Ratio Method (ARM) based on NO_2/NOx ratio of 0.80 and 0.75 for 1-hour and annual averaging times respectively.
[d] The 24-hour PM2.5 and federal 1-hour NO_2 standards are based on 3-year average of 98[th] percentile daily maximum values

Air Quality Table 43 summarizes the results of the modeling analysis for the modeled Overlap Scenario 2. The maximum SCGT construction short-term and annual emissions rates presented in **Air Quality Table 31** were used in conjunction with the maximum rolling 24-month emissions from 2008 through 2012 from AGS Units 3, 4, and 6 (later replaced by Unit 5), and AEC CCGT operating scenarios resulting in maximum impacts. The total impact is the sum of the existing background condition plus the maximum impact predicted by the modeling analysis for Overlap Scenario 2. The values in **bold** in the Background and Total Impact columns of **Air Quality Table 43** represent the values that either equal or exceed the relevant ambient air quality standard.

Air Quality Table 43
Proposed Maximum Overlap Scenario 2 Impacts, (μg/m^3)

Pollutant	Averaging Period	Project Impact[a] (μg/m^3)	Background (μg/m^3)	Total[b] Impact (μg/m^3)	Limiting Standard (μg/m^3)	Percent of Standard
NO_2[c]	1 hour	31.2	256	287	339	85%
	1 hour NAAQS[d]	25.6	146	172	188	92%
	Annual	0.93	48	49	57	85%
PM10	24 hour	12.8	**59**	72	50	**144%**
	Annual	2.24	**27.3**	29.5	20	**148%**
PM2.5	24 hour[d]	4.93	27.2	32.13	35	92%
	Annual	0.76	10.97	11.73	12	98%
CO	1 hour	234	3,665	3899	23,000	17%
	8 hour	111	2,978	3089	10,000	31%
SO_2	1 hour	2.39	58	61	655	9%
	1 hour NAAQS	2.14	31	33	196	17%
	3 hour NAAQS	2.14	58	60	1,300	5%
	24 hour	0.7	11	11	105	11%

Source: CH2 2016s Table 5.1-44, CH2 2016aa, CH2 2016bb, and staff analysis
Notes:
[a] Onsite construction only
[b] Modeled concentration plus background values adjusted by staff
[c] NO_2 determined with U.S. EPA Ambient Ratio Method (ARM) based on NO_2/NOx ratio of 0.80 and 0.75 for 1-hour and annual averaging times respectively.
[d] The 24-hour PM2.5 and federal 1-hour NO_2 standards are based on 3-year average of 98th percentile daily maximum values

Air Quality Tables 42 and 43 demonstrate that the emissions from the entire facility during routine operations would not cause new exceedances of any state or federal air quality standard. The PM10 emissions from the entire facility would contribute to existing violations of ambient air quality standards due to the high background concentrations. The direct impacts of NO_2, CO and SO_2 would not be significant because construction of the proposed facility modifications would neither cause nor contribute to a violation of these standards. Mitigation for construction emissions of PM10, PM2.5, SOx, NOx, and VOC would be appropriate for reducing impacts to PM10, PM2.5, and ozone.

Construction Mitigation

The facility owner proposes the following mitigation measures to reduce the exhaust emissions from the diesel heavy equipment and fugitive dust emissions during the construction of the proposed project modifications:

- Watering unpaved roads three times per day.
- During construction, watering areas disturbed by grading and bulldozing activities every three hours.
- Limiting onsite vehicle speed to 10 miles per hour, or other speeds as approved by the Energy Commission compliance project manager based on site conditions, and posting the approved speed limit.

- 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 2 weeks.
- Use of Tier 4 final 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.

Adequacy of Proposed Construction Mitigation

Staff generally concurs with the facility owner's proposed mitigation measures, which mirror many of the staff's mitigation recommendations from previous siting cases. But staff has been proposing additional fugitive dust mitigation, such as requiring the use of soil binders or paving to reduce emissions on unpaved roads, considered necessary to reduce the high fugitive dust emission potential during construction. Staff incorporates off-road equipment mitigation measures beyond those proposed by the facility owner to fully implement current staff recommendations.

Project Owner's Proposed Mitigation for Operation

The project owner is proposing to mitigate the proposed project's NOx, VOC, SOx, and PM10 emissions through the use of BACT and emission reduction credits (ERCs). BACT includes limiting the ammonia slip emissions to 5 ppm. The equipment description, equipment operation, and emission control devices are provided in **Project Description and Proposed Emissions** (above).

Emission Controls

The project owner proposes the use of dry low NOx combustors with selective catalytic reduction (SCR) to control NOx emissions to 2.0 ppmvd (1-hour average) for the GE 7FA.05 combined-cycle turbines and 2.5 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes the use of flue gas recirculation and SCR to control NOx emissions of the auxiliary boiler to 5.0 ppmvd corrected to 3 percent oxygen. The project owner is proposing best combustion design and the installation of an oxidation catalyst system to reduce CO emissions to 1.5 ppmvd for the GE 7FA.05 combined-cycle turbines and 2.0 ppmvd (1-hour average) for the GE LMS-100PB simple-cycle turbines. The project owner proposes to use flue gas recirculation and good combustion design to control CO emissions of the auxiliary boiler to 50 ppmvd at 3 percent oxygen.

The project owner proposes best combustion design and the installation of an oxidation catalyst system to control VOC emissions to 2.0 ppmvd (1-hour average) for the GE 7FA.05 combined-cycle turbines and the GE LMS-100PB simple-cycle turbines as BACT for VOC emissions. The use of pipeline quality natural gas and good combustion design for VOC control is BACT for the auxiliary boiler. Using best combustion practices, pipeline-quality natural gas, and inlet air filtration to limit PM10/PM2.5 emissions to 8.5 pounds per hour for the GE 7FA.05 turbines, 6.23 pounds per hour for the GE LMS-100PB turbines, and 0.51 pounds per hour for the auxiliary boiler are consistent with BACT at other similar sources. Operating exclusively on low sulfur pipeline-quality natural gas with a maximum fuel sulfur content of 0.75 grains/100 scf is the BACT for SOx.

Emission Offsets

The applicant proposes to provide emission offsets for PM10, SO_2 and VOC emissions and RECLAIM Trading Credits (RTCs) for NOx emissions consistent with SCAQMD Rules 1303, Rule 1304(a)(2), 1304.1 and 2005. Under SCAQMD Rule 1304(a)(2), PM10, SO_2 and VOC offsets for AEC would be secured from the SCAQMD internal accounts for the combined-cycle and simple-cycle turbines.

The applicant is proposing to provide VOC and PM10 offsets for the auxiliary boiler at a 1.2-to-1 ratio, consistent with SCAQMD Rule 1303(b)(2). The applicant has secured 5 pounds of VOC and PM10 emission reduction credits to fully offset the auxiliary boiler.

The applicant calculated the expected NOx RECLAIM requirements for the commissioning and operation scenarios. The applicant's expected SCAQMD RECLAIM requirements are included in **Air Quality Table 44**. The applicant states they hold sufficient NOx RTC allocations for the operating and commissioning periods outlined in **Air Quality Table 44**.

Air Quality Table 44
Applicant Expected RECLAIM Trade Credit Requirements

Equipment	(lbs/year)
	NOx, RTCs[a]
AEC CCGT Commissioning and Operation	220,432
AEC CCGT Operation	165,238
AEC CCGT Operation and SCGT Commissioning and Operation	293,102
AEC CCGT and SCGT Operation	270,213

Source: CH2 2016s Table 5.1-46

Adequacy of Proposed Mitigation

Emission Controls

The SCAQMD completed a detailed BACT evaluation for the AEC. The SCAQMD BACT evaluation concurred with the proposed BACT limits outlined above (see BACT analysis in the Compliance with LORS Section for a more detailed analysis). In addition, the SCAQMD evaluation includes commissioning, start up, and shutdown events.

During commissioning, it is not feasible to meet BACT limits for all periods of operation. The AEC CCGT, AEC SCGT, and auxiliary boiler would use low-NOx combustors that may not be optimally tuned during commissioning. In addition, the emissions are only partially abated as the control systems are installed and tested in stages. The turbines and boiler are not expected to operate at a full load during commissioning. The SCAQMD is proposing to add limits to the commissioning period for the CTGs and auxiliary boiler. In addition, maximum operating hour limits when emission controls are not available will be included for the AEC CCGT and AEC SCGT.

During startup periods, it is also not feasible to meet BACT limits for all periods of operation. The AEC CCGT, AEC SCGT and auxiliary boiler emission control equipment are not fully effective. It takes time for the catalyst to reach the recommended operating temperature. The SCAQMD is proposing cold, warm and hot startup events for the AEC CCGT and limiting the duration, emissions and total number of each startup event. SCAQMD is proposing to limit emissions from startup events for the AEC CCGT by restricting the number of events, the duration, and emission from startup. The SCAQMD is proposing cold, warm and hot startup events for the boiler and placing restrictions on the number of events and corresponding emissions.

During shutdown periods, it is not feasible to meet BACT limits for all periods of operation for all equipment. For the AEC CCGT and AEC SCGT, the SCR used to control emissions ceases operations. However, the SCR and CO catalysts are still above ambient temperature and partially controlling emissions. The SCAQMD is proposing to limit shutdown events including the number of events, duration and corresponding emissions.

Staff concurs with the SCAQMD's determination that the project's proposed emission controls/emission levels for criteria pollutants and ammonia slip meets BACT requirements (see full BACT discussion in Compliance with LORS).

Staff agrees with the District proposed District Permit Conditions to be included in the air quality conditions of certification.

Emission Offsets

SCAMD Rule 1303(b)(2) requires that all increases in emissions be offset unless exempt from offset requirements pursuant to District Rule 1304. Since CO is an attainment pollutant and not a precursor to any nonattainment pollutant offset requirements for CO are not applicable. Staff concurs that CO mitigation in the form of emission offsets would not be required for the AEC since modeling demonstrated the proposed project would not cause or contribute to a violation of a CO ambient air quality standard.

District Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement states that if electric utility steam boilers are replaced by combined-cycle gas turbine(s), or other advanced gas turbines (including intercooled turbines), the project would be exempt from emission offset requirements for non-RECLAIM pollutants unless there is a basin-wide electricity generation capacity increase on a per-utility basis. If there is an increase in basin-wide capacity, only the increased capacity must be offset via traditional offset rules and regulations. The language of this exemption allows for exemptions from offset and modeling normally required if the in-basin megawatt capacity of the utility receiving the facility's energy does not increase. The purpose was to facilitate the removal of older and less efficient boiler/steam turbine technology with cleaner gas turbine technology at the utilities. Since the advent of RECLAIM, the exemption was expanded to include modifications conducted for compliance with Regulation XX rules.

Per District Rule 1304, the project owner would be exempt from providing offset directly for the AEC combined-cycle and simple-cycle turbines. Instead, AEC would get the offsets from SCAQMD internal accounts. Per the FDOC, AES is proposing 1,094.7 MW of new generation for the two combined-cycle turbines (692.951 MW-gross total) and four simple-cycle turbines (401.751 MW-gross total) by retiring existing AGS Unit 1 (175 MW-gross), AGS Unit 2 (175 MW-gross), AGS Unit 3 (320 MW-gross), and AGS Unit 6 (480 MW-gross). AES has not identified plans for the surplus 55 MWs from the retirements of these four utility boilers. The generating capacity from AEC would be limited to 1094.7 MW by Condition of Certification **AQ-E11** (E448.1). In addition Condition of Certification **AQ-F5** (F52.1) would require the project owner to develop a plan to shut down AGS Units 1, 2, 3 and 6, to mitigate emissions of the new combined-cycle and simple-cycle units.

The operating equipment besides the combined-cycle and simple-cycle turbines would not be eligible for the offset exemption. Therefore, the project owner would need to provide offsets for the auxiliary boiler and the oil/water separators. The amount of offsets required for each pollutant is determined using the 30-day emission averages. The 30-day average is based on the highest emissions for any month, including a month where commissioning takes place. The offset ratio for ERCs is 1.2-to-1. The SCAQMD calculated offset requirements are included in **Air Quality Table 45**. The oil/water separator has a minimal contribution to the total VOC pound per day and is therefore included for completeness with the auxiliary boiler.

The Energy Commission mitigation requirements under CEQA are different than the SCAQMD offset requirements. The Energy Commission normally recommends mitigation on least a one-to-one ratio applied to the annual emissions expected to occur. For comparison, **Air Quality Table 45** also includes the maximum annual emissions from the auxiliary boiler and the oil/water separator and the calculated annualized daily emissions.

Air Quality Table 45
Project Offset Requirements for Emission Reduction Credits

Component	VOC	SOx	PM10
Auxiliary Boiler and Oil/Water Separator 30-Day Emission Averages (lb/day)	3.4	1.06	3.78
SCAQMD Offset Ratio for ERCs	1.2	1.2	1.2
Total Calculated (lb/day)	4.08	1.27	4.54
SCAQMD Rounded Required Offset (lb/day)	4	1	5
Maximum Annual Auxiliary Boiler and Oil/Water Separator Emissions (lb/yr)	1,223	382	1,362
Annualized Auxiliary Boiler and Oil/Water Separator Emissions (lb/day)	3.35	1.05	3.73

Source: SCAQMD 2016e Table 62, staff analysis
Note: [a] First Year

Air Quality Table 45 demonstrates that mitigation for VOC, SOx and PM10 in the form of ERCs required by the SCAQMD would be acceptable to staff since the SCAQMD proposed mitigation is more conservative than a pounds per day annual average emission calculation.

The AEC would have VOC, SOx and PM10 emission offset requirements for the auxiliary boiler and oil/water separators according to District Rule 1303. The project owner has provided ERCs of 4 pounds per day for VOC, 1 pound per day for SOx, and 5 pounds per day for PM10 for the auxiliary boiler and oil/water separators. The applicant provided a summary of the Certificates of Proof for Registered Emission Reduction Credit for VOC and PM10 ERCs. AES provided 5 pounds per day of VOC offsets; however, due to project refinements only 4 pounds per day will be required.. In addition, AES has provided 1 pound per day of SOx ERCs. Additional discussion of the ERCs surrendered is included in the Compliance with LORS Section.

The facility is still required to hold NOx RECLAIM Trading Credits (RTCs) to cover the first compliance year per Rule 1304.1. **Air Quality Table 32** includes the commissioning year maximum annual emissions, which would be the first year RECLAIM requirements for AEC. The first year of operation for the AEC CCGT and auxiliary boiler is expected to occur in 2020. Therefore, the first year NOx requirement for the AEC will include only the combined-cycle turbines and auxiliary boiler first year requirements since the first year of operation for the SGCT is expected to occur in 2021. The NOx RTC holdings for 2020 and 2021 from the current RECLAIM Annual Emission Allocations are also included in **Air Quality Table 46**.

Air Quality Table 46
Project RECLAIM Trade Credit Requirements (lbs/year)

Equipment	(lbs/year)
	NOx, RTCs[a]
Total AEC CCGT	216,754
Total AEC SCGT	274,300
Auxiliary Boiler	1,351
Required RECLAIM 1st Year - AEC CCGT and Auxiliary Boiler	218,105
NOx RTC Holding for 2020	432,413
Required RECLAIM 1st Year - AEC SCGTs	274,300
NOx RTC Holding for 2021	394,195

Source: SCAQMD 2016e Table 62, staff analysis
Note: [a] First Year

The NOx RTC holding for 2020 is greater than the first year RECLAIM NOx RTC requirements for the AEC CCGT and auxiliary boiler. In addition, the 2021 NOx RTC holding is greater than the first year RECLAIM NOx RTC for the AEC SCGT. Staff believes that the NOx RTCs are a valid mechanism to mitigate the NOx emissions due to the extensive monitoring and reporting requirement for the RECLAIM program.

District Rule 1304.1 – Electrical Generating Fee for Use of Offset Exemption requires electrical generating facilities using the specific offset exemption described in Rule 1304(a)(2) pay fees up to the full amount of offsets provided by the SCAQMD in accordance with Rule 1304. The project owner would be required to demonstrate compliance with the specific requirements of this rule prior to issuance of the Permits-to-Construct for the AEC. The FDOC noted that a payment option has been selected.

District Rule 1325 requires a major PM2.5 facility to offset PM2.5 emissions at the offset ratio of 1.1:1. A major polluting facility is defined in the rule as a facility located in a federally designated non-attainment area for PM2.5, with actual emissions, or a potential to emit of greater than 100 tons per year. The definition in SCAQMD Rule 1325 for major polluting facility was recently modified. After August 14, 2017 or until the effective date of the U.S. EPA's approval (whichever is later), the potential to emit in the definition would be lowered to 70 tons per year. The AGS has a potential to emit less than 100 tons per year and the AEC potential to emit would be 69.52 tons per year. The SCAQMD is proposing a permit that will limit facility PM2.5 to below 100 tons per year. Condition of Certification **AQ-F1** will incorporate the facility limit.

Staff's evaluation of the adequacy of project mitigation was determined solely based on the merits of this case, including the SCAQMD offset requirements, the project's emission limits, the specific ERCs proposed, and ambient air quality considerations of the region, and does not in any way provide a precedence or obligation for the acceptance of offset proposals for any other current or future licensing cases.

Staff Proposed Mitigation

Additional measures recommended by staff would reduce construction-phase impacts to a less than significant level by further limiting construction emissions of particulate matter and combustion contaminants. Staff believes that the short-term and variable nature of construction activities warrants a qualitative approach to mitigation. Construction emissions and the effectiveness of mitigation varies widely depending on variable levels of activity, the specific work taking place, the specific equipment, soil conditions, weather conditions, and other factors, making precise quantification of emissions and air quality impacts difficult. Despite this uncertainty, there are a number of feasible control measures that can and should be implemented to significantly reduce construction emissions. Staff has determined that the use of oxidizing soot filters is a viable emissions control technology for all heavy diesel-powered construction equipment that does not use an ARB-certified low emission diesel engine. In addition, staff proposes that prior to beginning construction, the facility owner should provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies mitigation measures to limit air quality impacts during construction.

Staff proposes Conditions of Certification **AQ-SC1** through **AQ-SC5** to implement these requirements. These conditions update the facility owner’s proposed mitigation to be consistent with the conditions of certification adopted in similar prior Energy Commission licensing cases. Compliance with these conditions is expected to greatly reduce or eliminate the potential for significant adverse air quality impacts during construction of the proposed AEC.

Staff is proposing Conditions of Certification **AQ-SC1** through **AQ-SC11.** Condition of Certification **AQ-SC1** requires an Air Quality Construction/Demolition Mitigation Manager to ensure compliance with the staff conditions for construction/demolition activities. Condition of Certification **AQ-SC2** would require a plan detailing the steps necessary to limit emissions from construction/demolition activities outlined in the Conditions of Certification. Condition of Certification **AQ-SC3** would require mitigation for fugitive dust control. The proposed mitigation is standard for Energy Commission projects and is similar to what was proposed by the applicant. Condition of Certification **AQ-SC4** would also require monthly reports to be submitted documenting compliance with the requirements. Condition of Certification **AQ-SC4** outlines monitoring requirements for dust from construction activities to ensure adequacy of the proposed mitigation. Condition of Certification **AQ-SC5** would require diesel-fueled engine control. Condition of Certification **AQ-SC5** would ensure that the cleanest engines available are used to protect public health and for consistency with the construction impact modeling. Condition of Certification **AQ-SC6** would require the project owner to provide copies to the Energy Commission Compliance Project Manager (CPM) of all air permits issued by the SCAQMD including any proposed modification.

Condition of Certification **AQ-SC7** would require quarterly reports to ensure ongoing compliance during commissioning and routine operation. Condition of Certification **AQ-SC8** would require mitigation for the proposed operation of the auxiliary boiler and oil/water separators. Condition of Certification **AQ-SC8** would establish the quantity of offsets required and ensure agency consultation if substitutions are made to the mitigation. Condition of Certification **AQ-SC9** would require the boiler to complete commissioning activities prior to the commissioning of the AEC CCGT. This condition is needed since overlap was not included as a modeling scenario. Condition of Certification **AQ-SC10** would require the AEC CCGT to complete commissioning activities prior to the commissioning of the AEC SCGT since overlap in these activities was not included as a modeling scenario.

Staff is also proposing the addition of an administrative Air Quality Condition of Certification **AQ-SC11**. This condition would allow the CPM to make insignificant changes to the air quality conditions of certification when appropriate. Condition of Certification **AQ-SC11** establishes appropriate guidelines on what would be considered a significant change. This condition is compatible with many air district rules and regulations which already have established mechanisms approved by ARB and U.S. EPA to make minor changes that do not involve significant change to existing monitoring, reporting or recordkeeping requirement or require a case by case determination of any emission limitation. This would allow the CPM to approve administrative changes (such as typographical errors, facility name or owner) and other minor changes. The condition requires the project owner to apply for the change and the CPM to approve the change before the change would become effective.

In addition staff is proposing some minor changes to the SCAQMD conditions provided in the FDOC. Condition of Certification **AQ-D11** (D29.3) allows for alternative tests methods to be used for source testing if there is concurrence with the U.S. EPA, ARB and SCAQMD. Staff is proposing to add this same flexibility to Condition of Certification **AQ-D13** (D29.5).

Cumulative Impacts and Mitigation

"Cumulative impacts" are defined as "two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts" (CEQA Guidelines, §15355). Such impacts can be relatively minor and incremental yet still be significant because of the existing environmental background, particularly when considering other closely related past, present, and reasonably foreseeable future projects.

Criteria pollutants have impacts that are usually (though not always) cumulative by their nature. Rarely will a project itself cause a violation of a federal or state criteria pollutant standard. However, many new sources contribute to violations of criteria pollutant standards because of elevated background conditions. Air districts attempt to reduce background criteria pollutant levels by adopting attainment plans, which are multi-faceted programmatic approaches to attainment. Attainment plans typically include new source review requirements that provide offsets and use Best Available Control Technology, combined with more stringent emissions controls on existing sources.

The discussion of cumulative air quality impacts includes the following three analyses:

- a summary of projections for criteria pollutants by the air district and the air district’s programmatic efforts to abate such pollution;
- an analysis of the project’s “localized cumulative impacts” direct emissions locally when combined with other local major emission sources; and
- a discussion of greenhouse gas emissions and global climate change impacts (in **Air Quality Appendix AIR-1**).

Summary of Projections

The SCAQMD is the agency with principal responsibility for analyzing and addressing cumulative air quality impacts, including the impacts of ambient ozone and particulate matter. The SCAQMD has summarized the cumulative impact of ozone and particulate matter on the air basin from the broad variety of its sources. Analyses of these cumulative impacts, as well as the measures the SCAQMD proposes to reduce impacts to air quality and public health, are summarized in four publicly available documents that the SCAQMD has adopted. These adopted air quality plans are summarized below.

- **Final 2012 Air Quality Management Plan** (adopted 12/07/2012)

  Link: http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/final-2012-air-quality-management-plan

- **Final 2007 Air Quality Management Plan** (adopted 06/01/2007)

  Link: http://www.aqmd.gov/home/library/clean-air-plans/air-quality-mgt-plan/2007-air-quality-management-plan

- **Final Socioeconomic Report for the Final 2012 AQMP** (adopted 12/07/2012)

  Link: http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2012-air-quality-management-plan/final-2012-aqmp-(february-2013)/final-socioeconomic-report-2012.pdf

- **State of California’s SIP for the new federal PM2.5 and 8-hour ozone standards** (adopted July 21, 2011)

  Link: http://www.arb.ca.gov/planning/sip/2007sip/2007sip.htm

2012 Air Quality Management Plan

The following paragraphs are excerpted from the Executive Summary of the 2012 Air Quality Management Plan adopted by the SCAQMD December 7, 2012:

> *The SCAQMD adopted (December 7, 2012) the 2012 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires a 24-hour PM2.5 nonattainment area to prepare a State Implementation Plan (SIP) which must be submitted to U.S. EPA by December 14, 2012. The SIP must demonstrate attainment with the 24-hour PM2.5 standard by 2014, with the possibility of up to a five-year extension to 2019, if needed. U.S. EPA approval of any extension request is based on the lack of feasible control measures to move forward the attainment date by one year. The District's attainment demonstration shows that, with implementation of all feasible controls, the earliest possible attainment date is 2014, and thus no extension of the attainment date is needed. In addition, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions (i.e., within the last five years) and approved motor vehicle emission models. The Final Plan is based on the most recent assumptions provided by both ARB and Southern California Association of Governments (SCAG) for motor vehicle emissions and demographic updates and includes updated transportation conformity budgets.*
>
> *The Final 2012 AQMP outlines a comprehensive control strategy that meets the requirement for expeditious progress towards attainment with the 24-hour PM2.5 NAAQS in 2014 with all feasible control measures. The Plan also includes specific measures to further implement the ozone strategy in the 2007 AQMP to assist attaining the 8-hour ozone standard by 2023. The control measures contained in the Final 2012 AQMP can be categorized as follows:*
>
>> *Basin-wide Short-term PM2.5 Measure. Measures that apply Basin-wide, have been determined to be feasible, will be implemented by the 2014 attainment date, and are required to be implemented under state and federal law. The main short-term measures are episodic, in that they only apply during high PM2.5 days and will only be implemented as needed to achieve the necessary air quality improvements.*
>
> *Contingency Measures. Measures to be automatically implemented if the Basin fails to achieve the 24-hour PM2.5 standard by 2014.*
>
> *8-hour Ozone Measures. Measures that provide for necessary actions to maintain progress towards meeting the 2023 8-hour ozone NAAQS, including regulatory measures, technology assessments, key investments, and incentives.*
>
> *Transportation Control Measures. Measures generally designed to reduce vehicle miles travelled (VMT) as included in SCAG's 2012 Regional Transportation Plan.*
>
> *Many of the control measures proposed are not regulatory in form, but instead focus on incentives, outreach, and education to bring about emissions reductions through voluntary participation and behavioral changes needed to complement regulations.*

The Basin faces several ozone and PM attainment challenges, as strategies for significant emission reductions become harder to identify and the federal standards continue to become more stringent. California's Greenhouse Gas reductions targets under AB32 add new challenges and timelines that affect many of the same sources that emit criteria pollutants. In finding the most cost-effective and efficient path to meet multiple deadlines for multiple air quality and climate objectives, it is essential that an integrated planning approach is developed. Responsibilities for achieving these goals span all levels of government, and coordinated and consistent planning efforts among multiple government agencies are a key component of an integrated approach.

To this end, and concurrent with the development of the 2012 AQMP, the District, the Air Resources Board, and San Joaquin Valley Air Pollution Control District engaged in a joint effort to take a coordinated and integrated look at strategies needed to meet California's multiple air quality and climate goals, as well as its energy policies. California's success in reducing smog has largely relied on technology and fuel advances, and as health-based air quality standards are tightened, the introduction of cleaner technologies must keep pace. More broadly, a transition to zero- and near-zero emission technologies is necessary to meet 2023 and 2032 air quality standards and 2050 climate goals. Many of the same technologies will address air quality, climate and energy goals. As such, strategies developed for air quality and climate change planning should be coordinated to make the most efficient use of limited resources and the time needed to develop cleaner technologies.

2007 Air Quality Management Plan

The following paragraphs are excerpted from the Executive Summary of the 2007 Air Quality Management Plan adopted by the SCAQMD June 1, 2007:

The SCAQMD adopted (June 1, 2007) the 2007 Air Quality Management Plan (AQMP) primarily in response to changes in the federal Clean Air Act (CAA). The CAA requires an 8-hour ozone nonattainment area to prepare a SIP revision by June 2007 and a PM2.5 nonattainment area to submit by April 2008. The SCAQMD has decided that it is most prudent to prepare a single comprehensive and integrated SIP revision that satisfies both the ozone and PM2.5 requirements. Additionally, the U.S. EPA requires that transportation conformity budgets be established based on the most recent planning assumptions and approved motor vehicle emission model. The AQMP is based on assumptions provided by both the California Air Resources Board (ARB) and the Southern California Association of Governments (SCAG) reflecting their upcoming model (EMFAC) for motor vehicle emissions and demographic updates.

The Final 2007 AQMP relies on a comprehensive and integrated control approach to achieve the PM2.5 standard by 2015 through implementation of short-term and mid-term control measures and achieve the 8-hour ozone standard by 2024 based on implementation of additional long-term measures. In order to demonstrate attainment by the prescribed deadlines, emission reductions needed for attainment must be in place by 2014 and 2023 timeframe.

The AQMP control measures consist of four components: 1) the District's Stationary and Mobile Source Control Measures; 2) ARB's Proposed State Strategy; 3) District Staff's Proposed Policy Options to Supplement ARB's Control Strategy; and 4) Regional Transportation Strategy and Control Measures provided by SCAG.

In order to achieve necessary reductions for meeting air quality standards, all four agencies (i.e., SCAQMD, ARB, U.S. EPA, and SCAG) would have to aggressively develop and implement control strategies through their respective plans, regulations, and alternative approaches for pollution sources within their primary jurisdiction. Even though SCAG does not have direct authority over mobile source emissions, it will commit to the emission reductions associated with implementation of the 2004 Regional Transportation Plan and 2006 Regional Transportation Improvement Program which are imbedded in the emission projections. Similarly, the Ports of Los Angeles and Long Beach have authority they must utilize to assist in the implementation of various strategies if the region is to attain clean air by federal deadlines.

Although the SCAQMD has completely met its obligations under the 2003 AQMP and stationary sources subject to the District's jurisdiction account for only 12% of NOx and 37% of SOx emissions in the Basin in 2014, the Final 2007 AQMP contains several short-term and mid-term control measures aimed at achieving further NOx and SOx reductions (as well as VOC and PM2.5 reductions) from these already regulated sources. These strategies are based on facility modernization, energy conservation measures and more stringent requirements for existing equipment (e.g., space heaters, ovens, dryers, furnaces).

Clean air for this region requires ARB to aggressively pursue reductions and strategies for on-road and off-road mobile sources and consumer products. In addition, considering the significant contribution of federal sources such as marine vessels, locomotives, and aircraft in the Basin (i.e., 56% of SOx in 2014 and 37% of NOx in

2023), it is imperative that the U.S. EPA pursue and develop regulations for new and existing federal sources to ensure that these sources contribute their fair share of reductions toward attainment of the federal standards. Unfortunately, regulation of these emission sources has not kept pace with other source categories and as a result, these sources are projected to represent a significant and growing portion of emissions in the Basin. Without a collaborative and serious effort among all agencies, attainment of the federal standards would be seriously jeopardized.

Final Socioeconomic Report for the Final 2012 AQMP

The following are excerpted from the Final Socioeconomic Report for the Final 2012 AQMP adopted by the SCAQMD December 7, 2012:

The 2012 AQMP has been prepared to meet the challenge of achieving healthful air quality in the South Coast Air Basin (Basin) and the Coachella Valley. This report accompanies the 2012 AQMP and presents the potential socioeconomic impacts resulting from implementation of this Plan. The information contained herein is considered by the South Coast Air Quality Management District (District) Governing Board when taking action on the Plan.

The 2012 AQMP control strategy is comprised of a traditional command-and-control approach, voluntary/incentive programs, and advanced technologies. Short- and near-term control strategies are proposed and will be implemented by the District, local and regional governments (e.g., transportation control measures provided in the 2012 Regional Transportation Plan), and the California Air Resources Board (ARB). These strategies include basin-wide short-term PM2.5 measures, episodic control measures for high PM2.5 days, measures to partially implement the Section 182I(5) commitment in the 2007 ozone SIP toward meeting the 8-hour ozone standard by 2024, and transportation control measures (TCM) adopted by the Southern California Association of Governments (SCAG). Many of the measures require behavioral changes and voluntary participation through outreach, incentive, and education. Implementation of these control strategies has potential effects on the region's economy.

The District relies on a number of methods, tools, and data sources to assess the impact of proposed control strategies on the economy. The involved applications include: integration of air quality data and concentration-response relationships to estimate benefits of clean air; capital, operating and maintenance expenditures on control devices and emission reductions to assess the cost of the Plan; and REMI (Regional Economic Models, Inc.) model to assess potential employment and other socioeconomic impacts (e.g., population and competitiveness).

Over the years, there has been an overall trend of steady improvement in air quality in the Basin. Additional emission reductions are still needed in order to bring the Basin into compliance with the federal 24-hour PM2.5 standard. Complying with the air quality standard would allow the District to avoid potential sanctions that could increase offset ratios for major sources and result in suspension of highway transportation funding. The benefits of better air quality through implementation of the 2012 AQMP include reductions in morbidity and mortality, visibility improvements, reduced expenditures on refurbishing building surfaces, and reduced traffic congestion.

The Draft 2012 Plan is projected to comply with the federal PM2.5 standard with an average annual benefit of $10.7 billion between 2014 and 2035. The $10.7 billion includes approximately $7.7 billion for congestion relief for all TCMs in the 2012 RTP, $2.2 billion for averted illness and higher survival rates, $696 million for visibility improvements, and $14 million for reduced damage to materials.

The analysis contained herein estimates that the benefits for the Plan significantly outweigh the anticipated costs. The measurement of clean air benefits is performed indirectly since clean air is not a commodity purchased or sold in a market. This often results in incomplete and underestimated benefits. The benefits of clean air (based on the total emission reductions required for attainment) for which a monetary figure can be applied are estimated to be $10.7 billion (including congestion relief benefits for all the TCMs) as compared to the estimated costs of $448 million on an average annual basis. There are, however, many benefits which are still unaccounted for, such as reductions in chronic illness and lung function impairment in human beings, reduced damage to livestock and plant life, erosion of building materials, and the value of reduced vehicle hours traveled for personal trips.

The Plan is designed to bring northwest Riverside (the Mira Loma area), the only area in exceedance of the federal PM2.5 standard, into attainment. However, PM2.5 air quality benefits occur throughout the Basin. The San Fernando Valley, southern Los Angeles County, and the northwest Riverside County would experience the highest shares of air quality benefits. The western portions of Los Angeles and Orange Counties and the eastern and northern portions of San Bernardino County are projected to have the highest shares of health benefits.

Implementation of PM2.5 and ozone measures would impose costs on various communities. The sub-regions with the highest costs are the central, southeast, and San Fernando areas of Los Angeles County. These three areas are projected to have the highest cost shares from SCAG TCMs and relative higher cost shares from ozone measures.

All sub-regions are projected to have additional jobs created from cleaner air. The eastern, southern, and San Fernando sub-regions in Los Angeles County and Riverside County are projected to have more jobs created than other sub-regions resulting from clean air benefits. Implementation of quantified control measures would result in jobs forgone between 2013 and 2035. Orange County is projected to have the highest share of jobs forgone from implementation of control measures. This is because the majority of SCAG transportation control measures (TCM) in Orange County would be financed by development fees, which would have a heavy burden on one single sector of the economy—the construction sector. For the entire Plan, all sub-regions would show positive job impacts as the four-county area becomes more competitive and attractive with the progress in clean air.

Job gains from cleaner air would benefit all wage groups. Conversely, all five groups would experience jobs forgone from control measures. However, there is no significant difference in impacts expected for high- versus low-paying jobs. The same is observed for impacts on the price of consumption goods from one income group to another. These findings will be further evaluated during individual rule development.

State of California SIP for the new federal PM2.5 and 8-hour Ozone Standards (adopted July 21, 2011)

On April 28, 2011, the ARB considered revisions to the South Coast (and San Joaquin Valley) State Implementation Plans (SIPs) for PM2.5 that accounted for reductions of emissions that contribute to PM2.5 levels. The revisions were formally adopted by the ARB's Executive Officer on May 18, 2011, when Executive Order S-11- 010 was signed. The April 2011 PM2.5 SIP Revisions accounted for recent regulatory actions and recessionary impacts on emissions that occurred after the South Coast (and San Joaquin Valley) PM2.5 SIPs were adopted in 2007 and 2008. Those revisions accounted for the impact the recession has had on emissions and the benefits of ARB's in-use diesel truck and off-road equipment regulations. The revisions updated the PM2.5 SIP's reasonable further progress calculations, transportation conformity budgets, and ARB's rulemaking calendar.

Localized Cumulative Impacts

The proposed new facility and other reasonably foreseeable projects could cause impacts that would be locally combined and future projects would introduce stationary sources that are not included in the "background" conditions. Reasonably foreseeable future projects are those that are either currently under construction or in the process of being approved by a local air district or municipality. Projects that have not yet entered the approval process do not normally qualify as "foreseeable" since the detailed information needed to conduct this analysis is not available. Sources that are presently operational are included in the background concentrations. Background conditions also take into account the effects of non-stationary sources.

Projects with stationary sources located up to six miles from the proposed project site usually need to be considered in the cumulative analysis.

On October 23, 2015 the applicant requested from SCAQMD an updated list of projects that are within six miles of the AEC site, that are either currently in the permitting process, undergoing CEQA review, or recently received a Permit to Construct (PTC). The SCAQMD provided a list on February 16, 2016. The facility owner requested copies of permit applications and source test reports for 12 sources. Information responsive to this request has not been provided.

The applicant proposed the use of the list of sources previously submitted to the Energy Commission on October 22, 2014 as part of the original AFC analysis. Staff agreed to the use of the list of sources previously obtained for he PSA analysis, however staff requests a refined analysis using an updated list for the Final Staff Assessment.

The sources and assumptions PM2.5 emission rates were assumed to be equivalent to PM10 emission rates in the cumulative analysis include:

Alamitos Energy Center - addition of two combined-cycle natural gas combustion turbines, four simple-cycle natural gas combustion turbines, and one natural gas auxiliary boiler:

- Source emission rates were based on the proposed updates to the AEC's operating profile in the revised Air Quality section submitted to the Energy Commission on April 12, 2016 (CH2 2016s).
- Source parameters and emission rates were selected according to the operating scenarios resulting in maximum predicted impacts.These scenarios include start-up and shutdown emissions and did not change in the updated modeling.

U.S. Government, Veterans Affairs - addition of six emergency diesel-powered generators:

- Source emission rates were based on source data received from the SCAQMD on July 29, 2014 and September 24, 2014.
- Unknown source locations were assumed to be at the property centroid.
- Emergency sources are permitted for up to 50 hours per year of maintenance and testing. The simultaneous testing of all emergency ICEs is not expected to occur within the same hour. Therefore, only a single emergency ICE with the highest hourly emission rates will be modeling.
- Emergency sources (like the ICEs) will not be modeled for the federal 1 hour NO_2 and SO_2 standards as these are statistical average standards that will not likely to be influenced by sources permitted to operate for up to 50 hours per year for testing and maintenance.
- The annual emissions from each of the six emergency diesel fueled ICEs were based on 50 hours of testing per year at the maximum hourly emission rate.

Trend Offset Printing Services, Inc. – modification of two VOC control afterburners and the addition of one control afterburner:

- Source parameters, locations and emission rates were based on permittees source data received from the SCAQMD on August 8, 2014.
- The permit applications for the two regenerative thermal oxidizers are for a change in conditions only. Any increase in emissions could not be determined from the information provided so the sources were included in the analysis using the respective emission limits.
- Source parameters, source location, and emision rates for the new RTO were based on peritted source data received from SCAQMD on July 28th, 2016. The source location was interpreted from relative distances to nearby schools and residences reported in the permitted source data.

Los Angeles City, Department of Water and Power (DWP) Haynes Generating Station – addition of six LMS100 simple-cycle gas turbines and two emergency diesel-powered generators:

- Source parameters and source locations for the simple cycle gas turbines were based on Prevention of Significant Deterioration (PSD) cumulative source data provided by DWP on October 23, 2013.
- Sources identified as emergency diesel ICEs are permitted for up to 50 hours per year of maintenance and testing. The simultaneous testing of the ICEs is not expected to occur within the same hour. Therefore, only a single emergency ICE with the highest hourly emission rates will be modeling.
- Emergency sources (like the ICEs) will not be modeled for the federal 1-hour NO_2 and SO_2 standards as these are statistical average standards that will not likely to be influenced by sources permitted to operate for up to 50 hours per year for testing and maintenance.
- Emission rates for all sources, as well as source parameters for the two emergency diesel ICEs, were provided in the SCAQMD engineering evaluation dated November 23, 2010.
- The emergency engines are permitted to operate for up to 50 hours per year for testing and maintenance. The emergency diesel IC engines were limited to a 30-minute testing period to be more reflective of expected operating conditions for the emergency engine.
- Since precise source locations for the two emergency diesel ICEs were not available in the SCAQMD engineering evaluation, the analysis placed them in an area of the site that houses generators.

The cumulative air quality impacts analysis results are included in **Air Quality Table 47**. The modeled impacts are combined with background concentrations to determine the total predicted impacts. As noted by the applicant, the background concentrations are considered conservative because they do not take into consideration the removal of the AGS boiler units.

Air Quality Table 47
Revised AEC Cumulative Impacts

Pollutant	Averaging Period	Cumulative Impacts ($\mu g/m^3$)	Background ($\mu g/m^3$)[a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1 hour	68.2	256	324	339	90%
	1 hour NAAQS	22.8	146	169	188	90%
	Annual	0.35	48	48	57	85%
PM10	24 hour	2.05	**59**	**61**	50	**122%**
	Annual	0.26	**27.3**	**27.6**	20	**138%**
PM2.5	24 hour	1.6	27.2	28.8	35	82%
	Annual	0.26	10.97	11.23	12	94%
CO	1 hour	187	3,665	3852	23,000	17%
	8 hour	44.7	2,978	3022.7	10,000	30%
SO_2	1 hour	2.11	58	60	655	9%
	1 hour NAAQS	1.6	31	33	196	17%
	3 hour NAAQS	1.71	58	60	1,300	5%
	24 hour	0.51	11	12	105	11%

Source: sCH2 2016t, Attachment DR133-3 Table 3,CH2 2016ee Table DR133-2R1, staff analysis
[a] Background values are adjusted as presented in **Air Quality Table 12**
[b] The total predicted concentrations for the federal 1-hour NO_2 standard and 24-hour PM2.5 standard are the 5-year average, high-8th- high modeled concentrations combined with the 3-year average, 98th percentile background concentrations.
[d] The total predicted concentration for the federal 1-hour SO_2 standard is the 5-year average, high-4th-high modeled concentration combined with the 3-year average, 99th percentile background concentration.

The background PM10 concentration in **Air Quality Table 47** exceed the AAQS without the addition of the cumulative sources. Therefore the particulate matter emissions from the AEC would be cumulatively considerable because they would contribute to existing violations of the PM10 ambient air quality standards. The project owner would mitigate emissions through the use of BACT, RTCs, emission offsets from the district's internal bank, and ERCs for the auxiliary boiler. Therefore, the cumulative operating impacts of AEC, after mitigation, are considered to be less than significant.

The impacts from NO_2, CO, SO_2 and PM2.5 emissions in the refined cumulative analysis are not expected to cause or contribute to a violation of any AAQS and are therefore considered to be less than significant.

Furthermore, as demonstrated in **Air Quality Table 47,** the contribution from the AEC and surrounding sources alone are a small percentage of the total impact. The background values account for the majority of the total impact even taking into consideration the conservative assumptions used for the cumulative modeling analysis. The cumulative increment from the construction, commissioning, and operation scenarios modeled for AEC would continue to be an insignificant increment with the proposed mitigation. Any potential cumulative impact from additional potential surrounding emissions sources, including but not limited to the demolition of the AGS would be dependent on the significance of the additional project emissions and not the operation of the AEC. Furthermore, the background values measured from surrounding monitors are assumed to include the operation of the existing AGS. Retirement or demolition of the AGS would imply the AGS units are no longer in operation and ongoing operation of the AGS units would no longer contribute to background values or cumulative impacts. Demolition of AGS, regardless of how it was performed, would be temporary and localized to the site compared with its operations.

Environmental Justice Impacts

Staff has considered the minority population surrounding the site and reviewed **Socioeconomics Figure 1** (see the **Socioeconomics** and **Executive Summary** sections of this document for further discussion of environmental justice), which shows the minority population within portions of the 6 mile buffer zone is greater than 50 percent, thus qualifying as an environmental justice population.

The staff-proposed CEQA mitigation measures noted as conditions of certification would reduce the proposed facility modifications' direct and cumulative air quality impacts to a less than significant level, including impacts to the environmental justice population. Therefore, there are no air quality environmental justice issues related to the proposed facility modifications and no minority or low-income populations would be significantly or adversely impacted.

COMPLIANCE WITH LORS

The Final Determination of Compliance (FDOC) for the AEC was docketed November 18,, 2016. Compliance with all SCAQMD Rules and Regulations was demonstrated to the SCAQMD's satisfaction in the FDOC, and the FDOC conditions are included in the staff-proposed conditions of certification below.

FEDERAL

Title 40 Code of Federal Regulations Subchapter C –Air Programs

40 CFR Part 50 National Primary and Secondary Ambient Air Quality Standards

40 Code of Federal Regulations (CFR) Part 50 National Primary and Secondary Ambient Air Quality Standards codifies the NAAQS. The project owner conducted dispersion modeling to determine if the proposed project would exceed and AAQS. The modeling analysis demonstrated the AEC would not cause a violation for any of the criteria attainment pollutants during normal operations (including startup and shutdown periods). Nonattainment pollutant emissions would be mitigated consistent with SCAQMD's SIP approved NSR program.

40 CFR Part 51 Requirements for Preparation, Adoption, and Submittal of Implementation Plans

40 CFR Part 51 Requirements for Preparation Adoption and Submittal of Implementation Plans requires NSR permitting for new stationary sources. NSR applies to sources of designated nonattainment pollutants. The NSR permitting is addressed through SCAQMD Regulation XIII. A Permit to Construct and Permit to Operate would be obtained by the project owner satisfying the requirements.

40 CFR Part 52 Approval and Promulgation of Implementation Plans

40 CFR Part establishes procedures for allowing new sources of air pollution to be constructed or existing sources to be to be modified in areas classified as attainment. Prevention of Significant Deterioration (PSD) requirements apply on a pollutant specific basis for major stationary sources. The AEC would be considered one of 28 source categories that are subject to PSD requirements for attainment pollutants if facility annual emissions exceed 100 tons per year. The AEC would exceed the 100 tons per year threshold for NOx and CO and is subject to the PSD analysis requirements. AEC would also be a major stationary source of GHG (exceeding 100,000 tons per year) which requires a PSD analysis for GHGs. The facility owner submitted the PSD application to the SCAQMD. See SCAQMD Regulation XVII for additional analysis.

Title 40 Code of Federal Regulations Part 60 Standards of Performance for New Stationary Sources

40 CFR Part 60 Subpart A –General Provisions

Any source subject to an applicable standard under 40 CFR Part 60 is also subject to the general provisions of Subpart A. Subpart A outlines general provisions for the proposed AEC including notification, work practice, monitoring and testing requirements. Compliance is expected.

40 CFR Part 60 Subpart Dc –Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

This subpart affects steam generating units with heat input rates between 10 and 100 million British thermal units per hour (MMBtu/hr) installed after June 9, 1989. The auxiliary boiler is subject to this requirement. The auxiliary boiler would be fired exclusively on natural gas and therefore would only be required to maintain monthly fuel consumption records. The auxiliary boiler would also have to meet Rule 2012 requirements of recording monthly fuel usage using a non-resettable totalizing fuel meter. Rule 2012 requires the use of a continuous emission monitoring system (CEMS). The conditions of certification would contain appropriate measures and compliance is expected.

40 CFR Part 60 Subpart KKKK –Standards of Performance for Stationary Combustion Turbines

This subpart establishes NOx and SO_2 emission limits for new combustion turbines. New combustion turbines with a rated heat input greater than 850 MMBtu/hr are required to meet NOx emission limits of 15 ppm at 15 percent oxygen. The fuel sulfur would be limited to 0.060 lbs SO_2 per MMBtu. Combustion turbines regulated under Subpart KKKK are exempt from Subpart GG.

The proposed AEC combined-cycle and simple-cycle turbines would meet the Subpart KKKK requirements with the use of dry-low NOx and SCR systems limiting NOx emissions to 2.0 ppm and 2.5 ppm. AEC would be limited to pipeline quality natural gas as fuel to meet SO_2 emission requirements. The AEC combined-cycle and simple-cycle turbines would monitor NOx emissions with a CEMS. The conditions of certification would contain appropriate measures.

40 CFR Part 60 Subpart TTTT –Standards of Performance for Greenhouse Gas Emissions for Electrical Generating Units

On August 3, 2015, the U.S. EPA promulgated New Source Performance Standards Subpart TTTT-Standards of Performance for Greenhouse Gas Emissions for Electrical Generating Units (Title 40, Code of Federal Regulations, Part 60.5508) (Subpart TTTT). The notice was published in the Federal Register on October 23, 2015 and had an immediate effective date. Subpart TTTT-Standards of Performance for Greenhouse Gas Emissions for Electrical Generating Units sets standards to limit emissions of CO_2 from new, modified and reconstructed power plants. Subpart TTTT- requirements are set under the authority of the Clean Air Act section 111(b) and are applicable to new fossil fuel-fired power plants commencing construction after January 8, 2014. The AEC combined-cycle and simple turbines are subject to Subpart TTTT requirements.

Subpart TTTT has different requirements based on whether the emission unit is considered base load. According to Subpart TTTT, base load rating is defined as maximum amount of heat input that an electrical generating unit (EGU) can combust on a steady state basis at ISO conditions. Each EGU is subject to the standard if it burns more than 90% natural gas on a 12-month rolling basis and if the EGU supplies more than the design efficiency times the potential electric output as net-electric sales on a 3 year rolling average basis. An affected EGU supplying equal to or less than the design efficiency times the potential electric output as net electric sales on a 3 year rolling average basis is considered a non-base load unit and is subject to a heat input limit of 120 lbs CO_2/MMBtu. Each affected 'base load' EGU is subject to the gross energy output standard of 1,000 lbs of CO_2/MWh unless the Administrator approves the EGU being subject to a net energy output standard of 1,030 lbs CO_2/MWh.

If the combined-cycle block operates above the "design efficiency" of 56% (or 50%, whichever is less), the 1000 lb CO_2/MWh-gross standard is applicable. The applicant has provided thermal emissions calculations for 31.37% capacity factor. Since GHG efficiency increases with increased capacity factor, the 937.88 lb CO_2 /MWh-HHV-gross (with degradation) demonstrates that the combined-cycle block can meet the 1000 lb CO_2/MWh-gross standard.

Conditions of certification will be added to ensure compliance with Subpart TTTT. Condition of Certification **AQ-E6** (E193.11) provides the 1,000 pounds per gross megawatt-hours CO_2 emission limit (inclusive of degradation) shall only apply if a turbine supplies greater than 1,481,141 MWh-net electrical output to a utility distribution system on both a 12-operating-month and a 3-year rolling average basis. Compliance with the 1,000 pounds per gross megawatt-hours CO_2 emission limit (inclusive of degradation) is determined on a 12-operating month rolling average basis.

Condition of Certification **AQ-E7** (E193.12) provides the 120 pounds per MMBtu CO_2 emission limit shall only apply if a turbine supplies no more than 1,481,141 MWh-net electrical output to a utility distribution system on either a 12-operating-month or a 3-year rolling average basis. Compliance with the 120 pounds per MMBtu CO_2 emission limit is determined on a 12-operating month rolling average basis.

Condition of Certification **AQ-E7** (E193.14) limits the CO_2 emissions to 610,480 tons per year per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO_2 emissions are limited to 937.88 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

The simple-cycle block would not be able to comply with the 1000 pounds per gross megawatt-hours CO_2 emission limit. Therefore the units would be restricted to operate below the base load threshold. Therefore the simple-cycle block must comply with Subpart TTTT emission limit of 50 kg CO_2 per GJ of heat input (120 lb CO_2/MMBtu). Compliance with this standard can be demonstrated by the exclusive use of natural gas as fuel.

Condition of Certification **AQ-E8** (E193.13) requires the 120 pounds per MMBtu CO_2 emission limit for non-base load turbines shall apply. Compliance with the 120 pounds per MMBtu CO_2 emission limit is determined on a 12-operating month rolling average basis.

Condition of Certification **AQ-E8** (E193.15) limits the CO_2 emissions to 120,765 tons per year per turbine on a 12-month rolling average basis from the GHG emissions calculations above. In addition, the calendar annual average CO_2 emissions are limited to 1,356.03 pounds per gross MW-hour (inclusive of degradation) from the thermal efficiency calculations above.

40 CFR 63, National Emission Standards for Hazardous Air Pollutants (NESHAPs).

The NESHAP regulations establish emission standards to limit emissions of HAPs from specific source categories. The FDOC demonstrates that with the installation of the proposed new units, the facility total HAP emissions would be below the 25 tons per year total or 10 ton per HAP major source threshold. Therefore the facility would not be subject to the requirements of this subpart. In addition the facility is not proposing to permit any diesel fired emergency equipment and therefore would not be subject to Subpart ZZZZ requirements.

40 CFR Part 64 – Compliance Assurance Monitoring (CAM)

The CAM rule establishes monitoring requirements for emission control systems. The CAM rule applies to emission units with uncontrolled potential to emit levels greater than applicable major source thresholds. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits.

The combined-cycle turbines NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx, CO, and VOC emissions are higher than the major source thresholds. Specifically, the NOx emissions are 54.19 tons per year (commissioning year), which is higher than the 10 tons per year major source threshold. The CO emissions are 124.58 tons per year (commissioning year), which is higher than the 50 tons per year threshold. The VOC emissions are 30.07 tons per year (commissioning year), which is higher than the 10 tons per year threshold. Thus, the CAM regulations are applicable to the combined-cycle turbines for NOx, CO, and VOC.

The simple-cycle turbines NOx, CO, and VOC emissions are subject to BACT limits. Each turbine is controlled with an SCR and CO catalyst to meet BACT limits. For each turbine, the highest annual post-control NOx and CO emissions are higher than the major source thresholds. Specifically, the NOx emissions are 34.29 tons per year (commissioning year), which is higher than the 10 tons per year major source threshold. The CO emissions are 37.47 tons per year (commissioning year), which is lower than the 50 tons per year threshold. The VOC emissions are 9.3 tons per year (commissioning year), which is lower than the 10 tons per year threshold. Thus, the CAM regulations are applicable to the simple-cycle turbines for NOx.

For each turbine, a CEMS will be installed for NOx and for CO. The NOx and CO CEMS qualify as continuous compliance determination methods and provide an exemption from this subpart for NOx and CO.

This subpart applies to the VOC emissions because the VOC BACT limit is achieved with the assistance of the oxidation catalyst. The oxidation catalyst is primarily installed to control CO emissions, but also controls VOC emissions. The oxidation catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. To assure that the catalyst is operating as designed, each turbine would be required to be source tested every three years for VOC pursuant to Condition **AQ-D11** (D29.3).

The auxiliary boiler NOx and CO emissions are subject to BACT limits. The boiler is controlled with an SCR to meet the BACT limit for NOx. The highest annual post-control NOx emission is lower than the major source threshold. Specifically, the NOx emissions are 0.68 tons per year, which is lower than the 10 tons per year major source threshold. The CO emissions are 3.63 tons per year are lower than the 50 tons per year threshold. Thus, the CAM regulations are not applicable to the auxiliary boiler.

40 CFR 70, Operating Permits Program

The Operating Permits Program requires the issuance of Title V permit identifying all applicable federal performance, operating, monitoring, recordkeeping and reporting requirements. The Title V requirements apply to facilities considered major sources having the potential to emit greater than10 tons per year NO_x or VOC, 100 tons per year of SO_2, 50 tons per year of CO, or 70 tons per year of PM_{10}, if the HAP potential to emit is greater or equal to 25 tons per year for combined HAPs and 10 tons per year for individual HAPs.

The AEC facility would exceed Title V thresholds and would be required to obtain a Title V permit. SCAQMD has received delegation authority for this program through SCAQMD Regulation XXX. The facility owner filed an application for an amendment to the existing facility Title V permit for AGS.

40 CFR 72, Acid Rain Program

The acid rain program establishes emission standards for SO_2 and NOx through the use of market incentives, monitoring and reporting requirements, and can require SO_2 allowances to be acquired in order to offset the annual SO_2 emissions.

The AEC would comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO_2 credits are needed, the project owner would obtain the credits from the SO_2 trading market. Compliance with this rule is expected.

STATE

The project owner would demonstrate that the project would comply with Section 41700 of the California State Health and Safety Code, which restricts emissions that would cause nuisance or injury. Conditions required in the SCAQMD's FDOC and the Energy Commission's affirmative finding for the project would ensure compliance.

LOCAL

The project owner provided an air quality permit application to the SCAQMD and the district has issued a FDOC which states that the proposed facility modifications are expected to comply with all applicable District rules and regulations.

The District rules and regulations specify the emissions control and offset requirements for new sources such as the proposed AEC. BACT would be implemented, RECLAIM trading credits (RTCs) for NOx emissions would be provided, ERCs for the emissions of the auxiliary boiler and oil/water separator would be provided, and VOC, SO_2 and PM10 emissions from the proposed new gas turbines are exempt from the offset requirements according to district rules and regulations based on the permitted emission levels for the facility modifications. Compliance with the district's new source requirements would ensure that the AEC would be consistent with the strategies and future emissions anticipated under the district's air quality attainment and maintenance plans.

The SCAQMD prepared a PDOC, published on July 1, 2016. A public noticing period is required. The FDOC was issued on November 18, 2016 and responded to comments received on the PDOC. The SCAQMD re-noticed the PDOC in November. The re-noticed comment period is still pending as of this writing. The FDOC evaluates compliance with the District's applicable rules and regulations, as summarized below.

<u>Regulation II – Permits</u>

Rule 205 – Expiration of Permit to Construct

This rule establishes that a SCAQMD permit to construct expires one year from the date of issuance unless a time extension has been approved in writing by the SCAQMD Executive Officer.

In addition SCAQMD Rule 1714 incorporates provisions of 40 CFR Part 52.21 – Prevention of Significant Deterioration of Air Quality by reference. Part 52.21 includes provisions that can invalidate approval for construction if construction is not commenced within 18 months after the receipt of the approval. Extensions can be granted when justified. Part 52.21 also states that BACT determination for phased construction projects shall be reviewed and modified as appropriate at the latest reasonable time occurring no later than 18 months prior to construction.

SCAQMD Rule 1713 invalidates permits to construct if construction has not commenced within 24 months after receipt of approval or if construction is discontinued for a period of 24 months. An extension can be granted if justified.

The SCAQMD FDOC includes two conditions, E193.5 and E73.2, containing the requirements of Rule 205, 40 Part 52.21, and Rule 1713. SCAQMD condition E193.5 was expanded in the FDOC to provide additional detail and to define the AEC construction phases. E73.2 is a new condition detailing the BACT/LAER determination for the simple-cycle portion of the project, which SCAQMD identifies as Phase 2. Before Phase 2 could begin construction, reexamination of BACT requirements would be required. Conditions of Certification **AQ-E2** (E193.5) and **AQ-E14** (E73.2) include these requirements.

Rule 212 – Standards for Approving Permits

The facility modifications are subject to Rule 212(c)(1), 212(c)(2) and Rule 212(c)(3) public notice requirements.

Rule 212(c)(1) requires public notice for any new or modified equipment that may emit air contaminants located within 1000 feet from the outer boundary of a school. The nearest K-12 school, Rosie the Riveter Charter High School is located 971 feet away from the closest proposed combined-cycle turbine.

In accordance with subdivision (d) of this rule, the facility owner is required to distribute a public notice to each parent or legal guardian of children in any school within ¼ mile of the project facility and to each address within a radius of 1,000 feet from the outer property line. Kettering Elementary School is located within a ¼ mile of the proposed facility and therefore the public notice with also be required to be distributed to the parents and guardian of the students at that school.

Rule 212(c)(2) public notice is required for any new or modified facility which has onsite emission increases exceeding specified daily maximums. **Air Quality Table 48** includes the daily facility emissions and Rule 212(c)(2) thresholds.

Air Quality Table 48
Rule 212(c)(2) Applicability

AEC CCGT, AEC SCGT and Auxiliary Boiler	Emissions lbs/day					
	NOx	CO	VOC	SOx	PM10/2.5	Lead
AEC 30-day Averages	1,888	7,501	1,154	403	1,044	0
Rule 212(c)(2)	40	220	30	60	30	3
Exceed Daily Maximum	Yes	Yes	Yes	Yes	Yes	No

Source: SCAQMD 2016e Table 47

Rule 212(c)(3) requires public notice for new or modified equipment with emission increases of toxic contaminants that expose a person to a maximum individual cancer risk greater or equal to one in a million during a lifetime (70 year). Public notice will not be required since the maximum individual cancer risk from the stationary equipment would not expose a person to a maximum individual cancer risk greater than or equal to one in a million. Further analysis is in included in the Rule 1401 analysis and in the Public Health Section of this document.

SCAQMD prepared a public notice containing sufficient information to describe the project. The following public notice requirements were completed.

- On June 30, 2016 the SCAQMD electronically submitted the public notice, PDOC analysis and proposed Title V facility permit to the Energy Commission.
- On June 30, 2016 the SCAQMD published the public notice, PDOC analysis and proposed Title V facility permit for review on the SCAQMD website.
- On June 30, 2016 the SCAQMD electronically submitted the public notice, PDOC analysis, and proposed Title V facility permit to the U.S. EPA for a 45-day review.
- On June 30, 2016 the SCAQMD mailed or emailed the public notice (and the PDOC analysis and proposed Title V facility permit if appropriate) to AES and other persons listed in SCAQMD Rule 212(g)(3) (U.S. EPA Region IX, chief executives of the city and county where the project would be located, regional land use planning agency and state and federal land managers whose lands may be affected by potential project emissions), environmental groups, and other interested parties.
- The public notice, PDOC analysis, and proposed Title V facility permit were available for public review at the SCAQMD headquarters in Diamond Bar, and at the Bay Shore Neighborhood Library in Long Beach.
- On July 8, 2016 the SCAQMD published the Notice of Intent to Issue Permits in the Press Telegram newspaper.
- On July 28, 2016 AES provided verification that the public notice was distributed to all addresses within one quarter mile of the facility.
- On July 28, 2016 AES provided verification that the public notice was distributed to the parents and guardians of the students at Rosie the Riveter Charter High School and Kettering Elementary School.

Written comments were submitted to the SCAQMD on July 19, 2016 by AES and on August 9, 2016 by Helping Hand Tools. On August 17, 2016, the SCAQMD forwarded the comment letters to the U.S. EPA for review. The SCAQMD FDOC includes an addendum addressing the comments received during the comment period.

The SCAQMD is re-noticing the PDOC and proposed revised Title V permit. The re-noticing provides interested parties the opportunity to evaluate the PDOC since the PSA was published. No changes have been made to the original PDOC documents being re-noticed. The re-notice public notice describes how any new comments can be submitted. On November 10, 2016 SCAQMD redistributed the documents. On November 15, 2016, the documents were made available on the SCAQMD website and on November 17, 2016 the re-notice Notice of Intent to Issue Permits in the Press Telegram. The FDOC states AES is in the process of distributing the re-notice public notice to all addresses within one-quarter mile of the facility and to the parents and guardians of Rosie the Riveter Charter High School and the Kettering Elementary School. Proof of noticing was docketed by AES on December 5, 2016 (AEC 2016d).

The re-noticing could lead to additional changes imposed by the SCAQMD and future Energy Commission action could be required, depending on the scope of the changes and the timing of when they would occur.

Rule 218 – Continuous Emission Monitoring

The proposed combined-cycle and simple-cycle turbines would each be equipped with oxidation catalysts to control CO. Each turbine is required to be equipped with a CO CEMS to demonstrate compliance. The project owner will be required to submit an "Application for CEMS" for each proposed CO CEMS, retain records and follow reporting procedures once approval to operate the CO CEMS is granted. Compliance with this rule is expected.

Regulation IV – Prohibitions

Rule 401 – Visible Emissions

This rule prohibits the discharge of visible emissions which are as dark, or darker, than Ringelmann 1 for a period aggregating more than three minutes. The gas turbines and the auxiliary boiler would be fired exclusively with pipeline quality natural gas and subject to BACT requirements. Therefore, visible emissions are not expected from the turbines and auxiliary boiler and compliance with this rule is expected.

Rule 402 – Nuisance

This rule prohibits discharge of air contaminants or other materials in quantities that cause injury, detriment, nuisance, or annoyance to any considerable number of persons, or public, or have a natural tendency to cause injury or damage to business or property. Nuisance problems are not expected under normal operating conditions of the gas turbines, auxiliary boiler and other equipment. Compliance is anticipated.

Rule 403 – Fugitive Emissions

The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. Prohibitions include fugitive dust that remains visible in the atmosphere beyond the property line of the emission source.

During the construction period, the project may be subject to requirements including the submittal of a fully executed Large Operation Notification (Form 403N) to the SCAQMD Compliance Department by an individual who has completed the SCAQMD fugitive Dust Control Class, and daily records that document the specific dust control actions taken.

The PDOC/FDOC is intended to evaluate the operating emissions, including fugitive emissions during the operation of a facility and the control of these emissions. The PDOC/FDOC is not intended to evaluate fugitive emissions during the construction phase. During normal operations, fugitive dust is not expected from the gas turbines, auxiliary boiler, SCR oxidation catalysts, ammonia tanks and oil/water separators, therefore, compliance is anticipated.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits SO_2 emissions to 500 ppm for equipment not subject to the gaseous fuel sulfur emission concentration limits of 431.1. It limits CO emissions to 2,000 ppm. Since the gas turbines will be subject to Rule 431.1 and are expected to comply with Rule 431.1, the sulfur limit does not apply. Compliance with the CO limit of this rule is expected since the AEC CCGT are subject to the BACT CO emission limit of no more than 1.5 ppmv and the AEC SCGT are subject to the BACT CO emission limit of no more 2 ppmv at 15 percent oxygen. The auxiliary boiler will comply with a CO emission limit of 50 ppmv at 3 percent oxygen. Compliance with CO will also be verified through the CEMS data for the gas turbines.

Rule 409 – Combustion Contaminants

This rule applies to the AEC CCGT, AEC SCGT and auxiliary boiler. This rule limits combustion generated PM emissions to 0.1 grains/dscf calculated to 12 percent CO_2.The FDOC demonstrated that the PM loading would be 0.007 grains/dscf for the AEC CCGT, and 0.01 grains/dscf for the AEC SCGT. The auxiliary boiler emissions rate during normal operation of 0.15 pounds per hour is significantly less than the turbines, therefore, compliance with the 0.1 grains/dscf calculated to 12 percent CO_2 is expected.

Rule 431.1 – Sulfur Content of Gaseous Fuels

This rule requires that the sulfur content as H_2S of the natural gas shall be less than 16 ppmv. The natural gas fuel that AEC would use is pipeline quality natural gas supplied from the Southern California Gas pipeline, which is limited to maximum fuel sulfur content of less than 0.75 grains of sulfur per 100 standard cubic feet. The commercial grade natural gas has an average H_2S content of 4 ppm. Compliance is expected.

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. This rule limits combustion contaminants as PM to be either less than 11 lbs/hour, or less than 0.01 gr/dscf. For natural gas fired gas turbine engines almost all PM emissions are PM10 emissions. As calculated in the Rule 409 evaluation PM10 emissions are 0.003 gr/dscf for the combined-cycle turbines, and 0.005 gr/dscf for the simple-cycle turbines. Since they both are less than 0.01 gr/dscf, compliance is expected.

Regulation XI – Source Specific Standards

Rules 1134 – Emissions of NOx from Stationary Gas Turbine / 1135 – Emissions form NOx from Electric Power Generating Systems

These rules are superseded by NOx RECLAIM pursuant to Rule 2001, Table 1.

Rules 1146 – Emissions of Oxides of Nitrogen from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters as amended 11/1/13

NOx emissions are not subject to this rule because the rule is superseded by NOx RECLAIM pursuant to Rule 2001, Table 1. However, the CO emissions are still subject to this requirement. Rule 1146 establishes NOx and CO emissions and compliance requirements. The equipment BACT requirements are more stringent than the emissions requirements established through Rule 1146. Rule 1146 CO limit is 400 ppmv corrected to 3 percent oxygen. The BACT CO limit of 50 ppm for the auxiliary boiler would be required by Condition of Certification **AQ-A14** (A195.14), Condition of Certification **AQ-D13** (D29.5) would require initial source testing with set averaging periods and test methods, Conditions of Certification **AQ-D14** (D29.6) would require ongoing testing according to Rule 1146 frequency (currently every three years), and Condition of Certification **AQ-H1** (H23.7) would require compliance with all Rule 1146 requirements. RECLAIM supersedes Rule 1146 requirements. The boiler is a major NOx source and would be required to be equipped with a certified CEMS. Compliance with the CO requirements would be established through the applicable conditions of certification.

Regulation XIII – New Source Review

New emissions sources are subject to the requirements of New Source Review (NSR) as specified in Regulation XIII, which includes SCAQMD Rules 1300 through 1325. For RECLAIM facilities, this rule only applies to pollutants not addressed by Regulation XX RECLAIM. Therefore criteria pollutants PM10, SOx, VOC and CO are subject to Rules 1300 through 1325 and NOx is restricted through SCAQMD Rules 2000 through 2013. For clarity corresponding RECLAIM requirement analysis will be included in this section. The SCAQMD new source review rules are based on both NAAQS and CAAQS.

Rule 1303(a)(1) – BACT/LAER (PM10, SOx, VOC, CO)

Rule 2005(c)(1)(A) – BACT/LAER (NOx)

The use of BACT is required for new or modified sources resulting in uncontrolled emission increases of 1 pound per day of any nonattainment air contaminant, ozone depleting compound, or ammonia. Precursors to nonattainment air contaminants are treated as nonattainment air contaminants as well. SCAQMD Rule 1303 requires BACT for NOx (non-RECLAIM), SOx, VOC, PM10 and ammonia. SCAQMD Rule 2005 requires BACT for RECLAIM NOx. In addition, SCAQMD Rules 1701 and 1703 require BACT for CO.

SCAQMD Rule 1303 requires that BACT for sources located at major polluting facilities be at least as stringent as Lowest Achievable Emissions Rate (LAER) defined in the federal Clean Air Act**.** SCAQMD Rule 1302 defines ‘major polluting facility’. SCAQMD Rule 1302 was amended on November 4, 2016. The updated thresholds are included in **Air Quality Table 49.** The proposed units will be located at the AGS facility. **Air Quality Table 49** includes major facility thresholds and the AGS potential to emit.

Air Quality Table 49
Major Facility Applicability

	Emissions tons/year				
	NOx	**CO**	**VOC**	**SOx**	**PM10**
Major Facility Threshold	10	50	10	70	70
AGS Potential to Emit	**636**	**21,872**	**454**	50	**627**
Exceed Threshold	Yes	Yes	Yes	No	Yes

Source: SCAQMD 2016e Table 47

AGS exceeds the major facility for NOx, CO, VOC and PM10. If the threshold for any one criteria pollutant is exceeded then the facility is considered a major polluting facility and is subject to LAER for all pollutants subject to NSR.

SCAQMD Rule 1302(h) defines BACT as “the most stringent emission limitation or control technique which:

(1) has been achieved in practice (AIP) for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the U.S. EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.”

The first two requirements in the BACT definition are the federal requirements for LAER at major sources. The third part of the definition is unique to SCAQMD and some other areas in California, and allows for more stringent controls than LAER. For major polluting facilities, LAER is determined on a permit-by-permit basis.

A BACT analysis was performed for each type of equipment on a pollutant-by-pollutant basis. Detailed BACT determinations were included for each type of equipment in the SCAQMD PDOC. The BACT determinations for CO were revised in the FDOC.

The PDOC included a CO limit of 2.0 ppmvd at 15 percent oxygen for the CCGTs. The SCAQMD reviewed operational and validation data and determined that for BACT for CO from CCGTs without duct burning is 1.5 ppmvd at 15 percent oxygen.

The PDOC included a CO limit of 4.0 ppmvd at 15 percent oxygen for the SCGTs. The SCAQMD reviewed operational and validation data and determined that for BACT for CO from SCGTs is 2.0 ppmvd at 15 percent oxygen averaged over a 1-hour period. AES has secured a written performance guarantee from the equipment vendor to ensure the equipment can comply with the 2.0 ppmvd at 15 percent oxygen requirement.

Air Quality Table 50 includes BACT requirements, proposed and guaranteed emission levels for the AEC.

Air Quality Table 50
AEC BACT Requirements

Pollutant	Proposed BACT Emission Level	Proposed BACT System
Combined-Cycle Turbines		
NOx	2.0 ppm at 15 percent O_2	DLN Combustor with SCR
CO	1.5 ppm at 15 percent O_2	Oxidation Catalyst/GCPs
VOC[a]	2.0 ppm at 15 percent O_2	DLN Combustor Oxidation Catalyst
Sox	Sulfur content less than 1 grain per 100 scf	Pipeline Quality Natural Gas
PM10	Sulfur content less than 1 grain per 100 scf	Pipeline Quality Natural Gas /GCPs/inlet air filtration
NH_3	5.0 ppm at 15 percent O_2	NH_3 Reagent/SCR systems
Simple-Cycle Turbines		
NOx	2.5 ppm at 15 percent O_2	DLN Combustor with SCR
CO	2.0 ppm at 15 percent O_2	Oxidation Catalyst/GCPs
VOC	2.0 ppm at 15 percent O_2	DLN Combustor Oxidation Catalyst
Sox	Sulfur content less than 1 grain per 100 scf	Pipeline Quality Natural Gas
PM10	Sulfur content less than 1 grain per 100 scf	Pipeline Quality Natural Gas /GCPs/inlet air filtration
NH_3	5.0 ppm at 15 percent O_2	NH_3 Reagent/SCR systems
Auxiliary Boiler		
NOx	5.0 ppm at 3 percent O_2	ULNB/FGR/GCPs/SCR
CO	50 ppm at 3 percent O_2	Natural Gas/GCPs
VOC	None	Natural Gas/GCPs
PM10/SOx	Sulfur content less than 1 grain per 100 scf	Pipeline Quality Natural Gas
NH_3	5.0 ppm at 3 percent O_2	NH_3 Reagent/SCR systems
Ammonia Tanks		
NH_3	None	Use of a pressure vessel for storage and a vapor return line for transfer
Oil/Water Separator		
VOC	None	Fixed Covers

Source: CH2 2016s, CH2 2016ii, SCAQMD 2016e and staff analysis
DLN = dry low NOx
ULNB = ultra-low NOx burner
FGR = Flue gas recirculation
GCPs= Good combustion practices
[a] The original application proposed 1 ppm for VOC. However it is not clear if the equipment could meet 1 ppm using SCAQMD approved test methods. Therefore, SCAQMD can only verify a BACT level of 2 ppm.

BACT requirements would be included in Air Quality Conditions of Certifications **AQ-A9**, **A12**, and **A15** for the AEC CCGT; **AQ-A10**, **A13**, and **A15** for the AEC SCGTs; **AQ-A11** and **A14** for the auxiliary boiler; **AQ-C6** and **E12** for the ammonia storage tanks; and **AQ-E13** for the oil/water separator.

During commissioning periods, startups, and shutdowns for the AEC CCGT, AEC SCGT and auxiliary boiler, it is not technically feasible for the turbines to meet BACT limits and the equipment is exempt from meeting BACT requirements during these periods. However, additional conditions of certification restrict emissions levels and operation during these periods to minimize emissions. The additional Conditions of certification include **AQ-E3**, **C1** and **C2** for the AEC CCGT; **AQ-E4**, **C3**, and **C4** for the AEC SCGT; and **AQ-E5** and **C5** for the auxiliary boiler.

Rule 1303(b)(1) Modeling

Rule 1303 requires that through modeling, the applicant must substantiate that the proposed facility would not cause a violation, or make significantly worse an existing violation of any AAQS at any receptor location. Rule 1303 requires modeling for NO_2 (non-RECLAIM), CO, PM10 and SO_2. Rule 2005I(1)(B) requires modeling for NO_2 for RECLAIM facilities.

Compliance determinations are different for attainment and nonattainment pollutants. For attainment pollutants, NO_2, CO, SO_2 and PM10 (federal), the peak impact plus the worst–case background concentrations shall not exceed the most stringent AAQS. For nonattainment pollutants, PM10 (state) and PM2.5, where the background concentrations exceed the AAQS, the modeled peak impacts shall not exceed Rule 1303 significant change thresholds.

SCAQMD Rule 1304(a) exempts specified sources replacing existing electric utility under specific circumstances from modeling requirements. The two combined-cycle and four simple turbines qualify for this exemption. The auxiliary boiler would not be exempt and therefore modeling is required. However, AEC performed a complete modeling analysis including the entire facility. SCAQMD reviewed the modeling to determine compliance with SCAQMD rules and regulations. SCAQMD reproduced the modeling analysis and used updated background concentrations from 2012 to 2014. The SCAQMD modeling review is included with the FDOC and is summarized below:

- The modeled impacts from the auxiliary boiler are below all Rule 1303 thresholds.
- The project's health risks are less than the Rule 1401 cancer and non-cancer permit limits of 10 in one million and hazard index of 1 (see the Public Health Section for more discussion)
- All equipment is subject to SCAQMD Rule 2005 review for NO_2. Modeled impacts are below all ambient air quality thresholds for NO_2.

- The project is subject to PSD regulations for NO_2, PM10 and greenhouse gases (GHG). CO is not subject to PSD however impacts were included in the analysis. The project's CO and PM10 impacts do not exceed the SIL. NO_2 impacts exceeded the 1-hour NO_2 SIL so a cumulative assessment was conducted. The cumulative impact analysis exceeded the 1-hour SIL. However, the project's contribution is less than the SIL and is not considered a significant source.
- The project's impacts on visibility and deposition did not exceed the screening threshold.
- The modeling analysis conforms to SCAQMD regulations.

In the FDOC, the BACT levels for CO for the combined and simple cycle turbines decreased. The decrease in the BACT level did not require the project to be remodeled since the CO emission levels were lower than the levels previously modeled. The projects emissions did not cause an exceedance any CAAQS or NAAQS with the higher emission rate. Therefore exceedances are not expected with lower emission rates.

Rule 1303(b)(2) – Offsets

Rule 1303(b)(2) requires offsets for a net emission increase of any nonattainment air contaminant (PM10, VOC and SOx) unless exempt from offset requirements pursuant to Rule 1304. CO is an attainment pollutant and not a precursor to any nonattainment pollutant, and is therefore not subject to the offset requirements.

Rule 1304(a)(2) – Electric Utility Steam Boiler Replacement provides a modeling and offset exemption for utility boiler repower projects. The exemption applies to the combined-cycle and simple-cycle turbines.

Offsets are required for each emission unit and are determined using the 30-day emission average. The 30-day average is based on the highest emissions for any month, including a commissioning month. The SCAQMD uses an offset ratio of 1.2 – 1 for emission reduction credits (ERCs). Project 30-day averages are included in **Air Quality Table 51.**

Air Quality Table 51
Project 30-Day Emission Averages

Equipment	30-Day Average (lbs/day)		
	VOC	SOx	PM10
Auxiliary Boiler	3.4	1.06	3.78
Oil/Water Separator, CCGTs	0.0005	--	--
Oil/Water Separator, SCGTs	0.000073	--	--
Total Project	3.40	1.06	3.78

Source: SCAQMD 2016e Table 62

Air Quality Table 52 summarizes the ERC and RTCs required per SCAQMD rules and regulations (RTC quantification in Proposed Emissions, Total Facility section) The total facility NOx RTC requirements In **Air Quality Table 52** are for the first operating year and are separated into two categories, since the first year operation for the SCGTs will be after the first year operation of the auxiliary boiler and combined-cycle turbines.

Air Quality Table 52
Project ERC and RTC Requirements

Equipment	(lbs/year)	(lbs/day)		
	NOx, RTCs[a]	VOC	SOx	PM10
AEC CCGT	108,377	--	--	--
AEC CCGT	108,377	--	--	--
AEC SCGT	68,575	--	--	--
AEC SCGT	68,575	--	--	--
AEC SCGT	68,575	--	--	--
AEC SCGT	68,575	--	--	--
Auxiliary Boiler	1,351	4	1	5
Oil/Water Separator, CCGTs	--	--	--	--
Oil/Water Separator, SCGTs	--	--	--	--
Total CCGTS and Auxiliary Boiler	218,105	4	1	5
Total SCGTS only	274,300	--	--	--

Source: SCAQMD 2016e Table 63, staff analysis
Note: [a] First Year

ERCs have been provided for the AEC for SCAQMD VOC, SOx and PM10 offset requirements included in **Air Quality Table 52**. AES has provided the following certificates for the AEC:

- Reactive Organic Compound (or VOC) ERCs: ERC certificate number AQ014405 for 5 pounds per day for which 4 pounds per day will be used for the AEC.
- PM10 ERCs: ERC certificate number AQ014168 for 4 pounds per day and ERC certificate NO. AQ014169 for 1 pound per day will be used for the AEC.
- SOx ERCs: ERC certificate Number AQ014451 for 1 pound per day will be used for the AEC.

Rule 1303(b)(3) Sensitive Zone Requirements

Rule 2005 –Trading Zone Restrictions

These rules require credits to be obtained from the appropriate trading zone. The AEC would be located in zone 1. Therefore, ERCs and RTC used for SCAQMD rule compliance must be originated from zone 1 only.

Rule 1303(b)(4) Facility Compliance

The AEC would be required to comply with all applicable rules and regulation of the SCAQMD.

Rule 1303(b)(5) Major Polluting Facilities

Rule 2005 – Additional Federal Requirements for Major Stationary Sources

AEC is considered a major pollution source by the SCAQMD under Rule 1302, and subject to the following rules:

Rule 1303(b)(5)(A)/Rule 2005(g)(2) – Alternative Analysis

Rule 1303(b)(5)(A)/Rule 2005(g)(2) – Compliance with CEQA

Rules 1303 and 2005 specifies the alternative analysis requirements can be met through compliance with CEQA. The Energy Commission permitting process is a certified regulatory program under CEQA that meets the requirements.

Rule 1303(b)(5)(B) – Statewide Compliance

Rule 2005(g)(1) – Statewide Compliance

Rule 1303(b)(5)(B) requires a demonstration that all major stationary sources are owned or operated by such person in the state are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Rule 2005(g)(1) requires the applicant to certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards. In a letter dated 10/23/15, Stephen O'Kane, Manager, AES Alamitos, LLC, certified that all major stationary sources that are owned or operated by AES in California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emissions limitations and standards under the Clean Air Act.

The SCAQMD website provides compliance data for facilities located the in the SCAQMD jurisdiction. Prior to issuance of the SCAQMD Permits-to-Construct for Alamitos, the SCAQMD will confirm the compliance status of AES has not changed.

Rule 1303(b)(5)(C) –Protection of Visibility

Rule 2005(g)(4)—Protection of Visibility

Rule 1303(b)(5)(C) and Rule 2005(g)(4) require a modeling analysis for plume visibility if the net emission increases from a new or modified sources exceed 15 tons per year of PM10 or 40 tons per year of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area is within a specified distance. The applicant has identified the San Gabriel Wilderness, approximately 53 km from the AEC site, as the nearest Class I area. Since the AEC is not within 29 km, a visibility analysis is not required.

Rule 1304 – Exemptions

SCAQMD Rule 1304(a)(2) provides a modeling and offset exemption for utility boiler replacement projects. The exemption applies to the: "….replacement of electric utility steam boiler(s) with combined-cycle gas turbine(s), intercooled, chemically-recuperated gas turbines, other advanced gas turbine(s); solar, geothermal, or wind energy…..[t]he new equipment must have a maximum electrical power rating (in megawatts) that does not allow basinwide electricity generating capacity on a per-utility basis to increase. If there is an increase in basin-wide capacity, only the increased capacity must be offset." Offsets are still provided, but the exemption provides the offsets from the SCAQMD internal offset accounts.

Rule 1304(a)(2) provides an exemption for new qualifying equipment that has a maximum electrical rating (in megawatts) that is less than or equal to the maximum electrical rating (in megawatts) of the electric utility steam boiler(s) that the new equipment replaces. Both the new equipment and the existing electric utility boiler(s) must have the same owner and be located in the basin. The MW's for MW's used to calculate the AEC emission credits and offsets use the following AGS units: Utility Boiler No. 1 (175 MW-gross), No. 2 (175 MW-gross), Unit 6 (480 MW-gross), and No. 3 (320 MW-gross) at AGS, with the two combined-cycle turbines (692.951 MW-gross total) and four simple-cycle turbines (401.751 MW-gross total). AES has not identified plans for the surplus 55 MWs from the retirements of these four utility boilers. In addition, AES has not identified plans for the MWs from the retirement of Utility Boiler No. 4 (320 MW) and Utility Boiler No. 5 (480 MW).

Rule 1304.1 – Electrical Generating Fee for Use of Offset Exemption

This rule requires electrical generating facilities which use the specific offset exemption described in Rule 1304(a)(2) [Electric Utility Steam Boiler Replacement] to pay fees for up to the full amount of offsets provided by the SCAQMD. AEC has selected a payment option with the SCAQMD. The preliminary estimated annual payment would be required prior to the issuance of the Permits to Construct.

Rule 1313 - Permits to Operate

Rule 1313 Section (d) applies to the retirement plan for the existing AGS. Section (d) requires a maximum of 90 days may be allowed as a start-up period for simultaneous operation of the subject sources for replacement equipment. Condition of Certification **AQ-F5** (F52.1) limits simultaneous operation to 90 days, and sets forth a number of requirements for the retirement plan and the retirement of the AGS Boilers.

Rule 1313 Section (g) requires permits to have identified BACT conditions and monthly maximum emissions from the permitted source. The following conditions would have corresponding Conditions of Certification:

<u>Combined-Cycle Turbines</u>

- BACT–Conditions of Certification **AQ-A9**, **AQ-A12,** and **AQ-A15** (A195.8, A195.9, and A195.10) set forth the BACT limits for NOx, CO, and VOC, respectively.

- Monthly Emissions– Conditions of Certification **AQ-A1** (A63.2) sets forth the monthly limits for CO, VOC, PM10, and SOx. These limits indirectly limit NOx.

Simple-Cycle Turbines

- BACT– Conditions of Certification **AQ-A10**, **AQ-A13,** and **AQ-A15** (A195.11, A195.17, and A195.10) set forth the BACT limits for NOx, CO, and VOC, respectively.
- Monthly Emissions– Conditions of Certification **AQ-A2** (A63.3) sets forth the monthly limits for CO, VOC, PM10, and SOx. These limits indirectly limit NOx.

Auxiliary Boiler

- BACT– Conditions of Certification **AQ-A11** and **AQ-A14** (A195.13 and A195.14) set forth the BACT limits for NOx and CO, respectively.
- Monthly Emissions– Conditions of Certification **AQ-A3** (A63.4) sets forth the monthly limits for CO, VOC, PM10, and SOx. These limits indirectly limit NOx.

Selective Catalytic Reduction

- BACT— Conditions of Certification **AQ-A16** and **AQ-A17** (A195.15 and A195.16) set forth the BACT limit for the combined- and simple-cycle turbine SCRs (NH_3 at 15% O2) and auxiliary boiler SCR (NH_3 at 3% O2), respectively.
- Monthly Emissions— Monthly emission limits are applicable to basic equipment, not control equipment.

Ammonia Tanks

- BACT— Conditions of Certification **AQ-C6** (C157.1) requires the tanks to be equipped with a pressure relief valve set at 50 psig. Condition of Certification **AQ-E12** (E144.1) requires the tanks to be vented, during filling, to the vessel from which it is being filled.
- Monthly Emissions—The pressure relief valves and vapor return lines result in no ammonia emissions emitted from the tanks under normal operations.

Oil/Water Separators

- BACT— Conditions of Certification **AQ-E13** (E193.16) requires fixed covers for the tanks.
- Monthly Emissions—Throughput limits are not necessary because the 30-day averages for both tanks are no more than 0.0005 lb/day.

Rule 1325 – Federal PM2.5 New Source Review Program

This rule applies to major polluting facilities, major modifications to a major polluting facility, or any modifications to an existing facility that would constitute a major polluting facility in areas federally designated as federal nonattainment for PM2.5. This rule applies on a pollutant specific basis to emissions of PM2.5 and its precursors. For major modifications the source must be considered a major source, the modification results in a significant increase and the modification results in a significant net emissions increase.

A major polluting facility is defined as a facility with actual emissions, or a potential to emit of greater than 100 tons per year. The AEC would have a potential to emit over 100 tons per year for NOx, but below for SO_2 and PM2.5. In addition the net increase of NO_2 would be over 40 tons per year and is therefore considered significant. Therefore Rule 1325 is only applicable to NOx.

Conditions of certification would be included limiting the potential to emit for PM2.5 and SO_2 to 100 tons per year. Condition of Certification **AQ-F1** (F2.1) would limit the PM2.5 emissions for the facility to 100 tons per year. Conditions of Certifications **AQ-A1**, **AQ-A2**, and **AQ-A3** (A63.2, .3 and .4) limit annual emissions of SO_2 and PM10 from the combined-cycle and simple-cycle turbines and the auxiliary boiler.

The SCAQMD Rule 1325 PM2.5 threshold is pending change from 100 tons per year to 70 tons per year. The SCAQMD was reclassified as serious nonattainment for PM2.5 and federal regulations require a major source be classified as having the potential to emit of 70 tons per year for PM2.5.The new threshold does not apply until SCAQMD revises its PM2.5 NSR requirements.

Amendments to SCAQMD Rule 1325 include establishing appropriate major source thresholds for direct PM2.5 and PM2.5 precursors, including VOC and ammonia. The major polluting facility thresholds will be lowered from the current 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments are not expected to apply to ACE because they will not be effective until after August 14, 2017 or upon the effective date of EPA's approval of these amendments (whichever is later) while the Energy Commission decision should occur well before then. The proposed amendments were adopted on November 4, 2016.

Rule 1401 – New Source Review of Toxic Air Contaminants

Rule 2005(g)(4)—RECLAIM Rule 1401 Compliance

Rule 1401 specifies limits for maximum individual cancer risk (MICR), and acute and chronic hazard index from new permit units, relocations, or modifications to existing permits that emit toxic air contaminants (see Public Health Section for analysis).

Regulation XVII – Prevention of Significant Deterioration

The PSD program has been established to protect the deterioration of air quality in areas that already meet the primary NAAQS. The SCAQMD is partially delegated to issue initial PSD permits and for PSD permit modifications. AES has opted to apply for a PSD permit from the SCAQMD. The SCAB is in attainment for NO_2, SO_2, CO, and PM10 NAAQS. Therefore, the PSD regulation applies to NOx, SOx, CO, and PM10 emissions.

Rule 1701, 1702, 1706 – PSD Applicability

The SCAQMD is in attainment for the primary NAAQS for NOx, SOx, CO, and PM10. PSD applies to each regulated pollutant. **Air Quality Table 53** demonstrates PSD requirement applicability for each pollutant.

Air Quality Table 53
Prevention of Significant Deterioration Applicability

	CO	NOx	SO_2	PM10
AGS PTE (tons/year)	21,872	636	50	627
Major Source	Yes	Yes	Yes	Yes
AGS Actual Emissions - 2013-2014 (tons/year)	288	47	5	11
AEC PTE (tons/year)	244	137	10	70
Significant Emission Increase	Yes, increase is greater than 100 tpy	Yes, increase is greater than 40 tpy	No, increase is less than 40 tpy	Yes, increase is greater than 15 tpy
Net Emission Increase = AEC PTE – AGS Actual (tons/year)	- 44	90	6	59
Net Significant Increase	No	Yes	No	Yes
PSD Applicability	No	Yes	No	Yes

Note: PTE is "Potential to Emit" and tpy is "tons per year"
Source: SCAQMD 2016e Table 71, staff analysis

AEC would result in significant emissions increase for CO, NOx, and PM10, but not SO_2. The AEC would result in net significant increases for NOx and PM10, but not CO and SO_2. Therefore, CO and SO_2 are not subject to PSD requirements other than BACT.

Although CO is not subject to PSD requirements other than BACT, it is included for completeness in the SCAQMD review.

Rule 1703 (a)(2) and (a)(3)(B) Analysis –Top Down BACT

BACT applies to each permit unit for each criteria air contaminant for which there is a net emission increase. U.S. EPA outlines the process used to perform the required case-by-case analysis. The process is referred to as a Top-Down analysis and includes the following steps.

- Step 1: Identify all available control technologies
- Step 2: Eliminated technically infeasible options

- Step 3: Rank remaining control technologies
- Step 4: Evaluate the most effective controls
- Step 5: Select the BACT

The top down BACT analysis is consistent with the proposed systems included in **Air Quality Table 50**.

Rule 1703 (a)(3)(A) Analysis – Certificate of Compliance

A certified letter of compliance was submitted by AES stating that all major stationary sources owned and operated by AES in California subject to emission limitations are in compliance or on schedule tor compliance with all applicable standards under the Clean Air Act.

Rule 1703 (a)(3)(F) Analysis – Copy of Application to EPA, Federal Land Manager, Forest Service

AES submitted permit applications to the SCAQMD for the AEC on 10/23/2015. The SCAQMD deemed the AEC permit applications complete on 1/14/2016. On 1/20/2016, SCAQMD mailed the original applications including the modeling CDs to affected agencies. On 4/1/2016 the SCAQMD mailed the revised applications and modeling CDs to the same agencies. A representative from the National Park Service indicated they agree with the proposed project BACT and do not anticipate the project to affect any areas managed by the National Park Service. The Forest Service reviewed the project application had no comments on the project.

Rule 1703 (a)(3)(D), (a)(3)(C), (a)(3)(C), Analysis – Air Impacts

An air impacts analysis including modeling was performed for CO, $NO_{2,}$ and PM10. The following summarizes the Rule 1303, 2005, and 1703 modeling analysis:

1. Pre-construction monitoring is not required for the proposed AEC since the CO, NO_2 and PM10 impacts would not exceed the monitoring thresholds.

2. SCAQMD updated the background concentrations to include 2014 data.

3. Dispersion modeling demonstrated CO_2, NO_2 and PM10 will be incompliance with the primary NAAQS and CAAQS.

4. The maximum impacts for annual NO_2, 1-hr and 8-hr CO, and 24-hr PM10 are below the respective Class II significant impact levels (SILs).

5. The federal 1-hour NO_2 average impact for the proposed new units exceeds the Class II SIL of 7.52 $\mu g/m^3$. Therefore, a cumulative impact analysis of AEC and competing sources was required. The cumulative impact analysis demonstrated the maximum contribution to the modeled exceedance was less than the 1-hr NO_2 SIL. Therefore the impacts are considered less than significant.

6. A Class 1 area impact analysis demonstrated that the AEC would not adversely affect air quality-related values and will not cause or contribute to an exceedance of the Class I SIL.

7. A Class 1 increment impact analysis evaluated potential impacts to nearby Class 1 areas. The nearest Class I area is approximately 53 kilometers away from the AEC site. Impacts at this distance are below the applicable SIL.

8. The AEC facility would be built on an existing power plant site to replace existing electrical generating equipment. The project is not expected to induce growth or result in impacts to soils and vegetation.

9. AES evaluated wet and dry nitrogen deposition from depositional nitrogen emissions from AEC using AERMOD. The annual deposition is considered to be less than critical loads.

10. Dispersion modeling for normal operation demonstrated compliance with secondary NAAQS.

11. The visibility analysis used VISCREEN Tier 1 modeling to demonstrate each Class II area did not exceed the criteria for color contrast or plume contrast.

Rule 1714 Prevention of Significant Deterioration for greenhouse Gases

Air Quality Appendix AIR-1 includes the GHG analysis for the proposed AEC.

Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

Rule 2002 – Allocations for Oxides of Nitrogen (NOx) and Oxides of Sulfur (SOx)

This regulation establishes the applicable starting emission factor used for RECLAIM NOx until the CEMS is certified. The requirements are included in Conditions of Certification, **AQ-A4, AQ-A5, AQ-A6, AQ-A7,** and **AQ-A8** (A99.1, A99.2, A99.3, A99.4 and A99.5)

Rule 2005 – New Source Review for RECLAIM

This regulation applies only to NOx emissions for this facility because the owner is only intending to obtain NOx RTCs.

BACT

A top down BACT analysis was performed. As previously discussed, the proposed BACT is consistent with the SCAQMD BACT analysis.

Modeling

For existing RECLAIM facilities, the SCAQMD will not approve applications for amendments to add new emission equipment unless it is demonstrated the project would not result in a significant increase in the NO_2. Therefore modeling is required on a per permit unit basis. The revised application indicated the thresholds and standards are only applicable to the highest modeled concentrations corresponding to the combined-cycle turbine. **Air Quality Table 54** includes the modeled results for a single combined-cycle turbine.

Air Quality Table 54
Proposed AEC Routine Operations Impacts

Pollutant	Averaging Period	Project Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)[a]	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO_2	1 hour	13.8	256	270	339	80%
	1 hour NAAQS	12.4	146	158	188	84%
	Annual	0.1	48	48.1	57	84%

Source: SCAQMD 2016e Table 88, staff analysis
[a] Background values are adjusted as presented in **Air Quality Table 12**

The total impacts demonstrate the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards.

Additional Requirements

RECLAIM facilities are required to hold sufficient RECLAIM Trading Credits (RTCs) to offset the annual emission increase for the first year of operation. SCAQMD determined AEC would only have to hold offsets for the first year of operation for NOx-emitting equipment since RTC allocations would be less than the initial allocation when AES Corporation purchased the AGS.

Rule 2005(d) specifies the RECLAIM credit calculation shall be based on the potential to emit or on permit conditions limiting emissions. For the first year of operation RECLAIM allotments will be based the maximum commissioning year emissions.

RTCs Required to Be Held the First Year of Operation:

Combined-Cycle Turbines

Condition of Certification **AQ-I1** (I297.1 and I297.2) will require each turbine to hold 108,377 pounds of RTCs the first year.

Simple-Cycle Turbines

Condition of Certification **AQ-I2** (I297.3, I297.4, I297.5, and I297.6) will require each turbine to hold 68,575 pounds of RTCs the first year.

Auxiliary Boiler

Condition of Certification **AQ-I3** (I297.7) will require auxiliary boiler to hold 1,351 pounds of RTCs the first year from the annual emissions calculations.

Current RECLAIM Annual Emission Allocations indicates the current RTC holdings exceed the first year of operation requirement. For subsequent years, Rule 2004(b)(1) specifies actual NOx emissions will determine the number of RTCs required.

Additional Requirements

Trading zone restrictions and additional federal requirements are discussed in Rule 1303(b)(3) and (b)(5). Public notice requirements are included in Rule 212 analysis and Rule 1401 compliance is included in the Rule 1401 analysis.

Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM

The combined-cycle turbines, simple-cycle turbines and auxiliary boiler would be classified as major sources of NOx for RECLAIM purposes. The AEC would be required to use non-resettable fuel meters to record fuel usage and a NOx CEMS. The AEC would be required to install, operate, and maintain all recording systems within 12 months after initial startup. CEMS equipment is proposed for the combined-cycle turbines, simple-cycle turbines and auxiliary boiler. Conditions of certification would require the CEMS would to be installed within 12 months from the date of installation of the turbines. Thus, the operation of the new turbines would be in compliance with Rule 2012.

Regulation XXX – Title V Operating Permit

The AEC is considered as a significant permit revision to the RECLAIM/Title V permit for the AGS facility. A proposed Title V permit incorporating permit revisions will be submitted to U.S EPA for a 45-day review. All public participation procedures are required be followed prior to the issuance of the permit.

The public notice is required to include the following:

1. The identity and location of the affected facility;

2. The name and mailing address of the facility's contact person;

3. The identity and address of the SCAQMD as the permitting authority processing the permit;

4. The activity or activities involved in the permit action;

5. The emissions change involved in any permit revision;

6. The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph(b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;

7. A brief description of the public comment procedures provided; and

8. The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

The Title V public notice will be combined with the Rule 210 noticing. The public notice periods for both are anticipated to run concurrently.

RESPONSE TO PSA COMMENTS

Please note that responses to comments on the GHG assessment are included in the **Air Quality Appendix AIR-1**for GHG emissions.

PROJECT OWNER COMMENTS

Alamitos Energy Center (13-AFC-01) Preliminary Staff Assessment Initial Comments, Dated July 27, 2016 (CH 2016AA)

Comment 1:

Page 4.1-1, Summary of Conclusions, first paragraph – AES mailed notices to parents/guardians of students attending Rosie the Riveter Charter School and all addresses within ¼ mile of the outer boundary of the facility on July 12, 2016. Notices to parents/guardians of students attending Kettering Elementary School was mailed on July 25, 2016. Additionally, per page 180 of the Preliminary Determination of Compliance (PDOC), AES has agreed to provide at least 1 pound per day (lb/day) of emission reduction credits (ERCs) for sulfur oxides (SOx) emissions (see Transaction # 212045). Therefore, the Final Staff Assessment should reflect that the AEC project does not significantly impact air quality and complies with applicable air quality regulations.

Response to Comment 1:

The PSA was published prior to the completion of the applicant's noticing requirements. Staff reviewed the applicant's subsequent submittals and incorporated updates in the FSA as appropriate.

Comment 2:

Page 4.1-12, Air Quality Table 3 – There is no federal ambient air quality standard for sulfates. Please replace the word Attainment with No Federal Standard.

Response to Comment 2:

Staff updated **Air Quality Table 3** in the FSA.

Comment 3:

Page 4.1-17, Air Quality Table 8 – The annual particulate matter with aerodynamic diameter less than or equal to 2.5 microns (PM2.5) concentration for 2009, measured at the North Long Beach monitoring station, should be 13.0 micrograms per cubic meter ($\mu g/m^3$) and not 30.5 $\mu g/m^3$.

Response to Comment 3:

Staff updated **Air Quality Table 8** in the FSA.

Comment 4:

Page 4.1-20, Air Quality Table 12 – The 24-hour PM2.5 concentration should be 25.6 μg/m^3, based on the 3-year average of maximum values, rather than the 3-year maximum value of 27.2 μg/m^3. This change should be made to all modeling results tables in the PSA, where applicable.

Response to Comment 4:

The 24-hour PM2.5 ambient air quality standard is attained when 98 percent of the daily concentrations, averaged over three years, are equal to or less than the standard. The maximum 3-year 98th percentile PM2.5 background value was selected by staff to represent the background value, not to determine if the representative background value is in attainment of the 24-hour PM2.5 AAQS. The total impact, the representative background plus the project's impact, is compared to the ambient air quality standard value to evaluate attainment. Therefore, the selected background value conservatively represents background concentrations. In addition, the analysis indicated the total project impact including the background concentrations is below the PM2.5 AAQS. Given the results of the analysis, staff does not see a reason to further refine the background values selected.

Comment 5:

Page 4.1-22, Project Description and Proposed Emissions, fourth paragraph – Existing Alamitos Generating Station Unit 3 will be retired once the AEC simple-cycle turbine generator (SCTG) reaches the commissioning stage and becomes operational or by the December 31, 2020, whichever occurs first.

Response to Comment 5:

Staff added additional text in the FSA to further clarify the OTC policy requirements.

Comment 6:

Page 4.1-23, Construction, third paragraph – The PSA states "This offsite laydown area is also being proposed for use in the Huntington Beach Energy Project (HBEP)." As described on page 4.11-25, **Traffic and Transportation**, a maximum of 24 heavy/oversized deliveries could possibly be diverted to the offsite AES laydown area, if the HBEP project is not yet ready to receive those deliveries. HBEP has an incentive to avoid using the AEC site whenever possible for these 24 deliveries, since temporary use of the laydown results in HBEP equipment being moved twice.

Response to Comment 6:

Staff requested additional clarification in the PSA workshop if any action is being requested from the applicant regarding these comments. The applicant's response in the workshop indicated the purpose of the comment was to provide an update to the use of the laydown area and no action was requested of staff.

Comment 7:

Page 4.1-25, Initial Commissioning, first paragraph – Abated commissioning activities should be 336 hours, not 338 hours.

Response to Comment 7:

Staff updated the text in the FSA.

Comment 8:

Page 4.1-25, Air Quality Table 15 – It appears that the SOx and particulate matter with aerodynamic diameter less than or equal to 10 microns (PM10/PM2.5) emission values data are switched. Please correct the SOx and PM10/PM2.5 emission data and emission factors in Air Quality Table 15.

Response to Comment 8:

Staff updated the text in the FSA.

Comment 9:

Page 4.1-31, Air Quality Table 26 – Hourly volatile organic compound (VOC) emissions for the hot start scenario should be 0.96 pounds per hour (lbs/hr), not 0.69 lbs/hr.

Response to Comment 9:

Staff requested additional information regarding the VOC emission factor for the boiler hot start scenarios. The 0.69 pounds per event value was accidentally reported in the PSA in the pounds per hour cell. The 0.69 pounds per event value remains in the **Air Quality Table 26** and the pounds per hour value has been corrected to 0.96 underneath the per event row in **Air Quality Table 26** in the FSA.

Comment 10a:

Page 4.1-33, Air Quality Table 30 – The daily usage for four SCTGs should be 84,384 million British thermal units (MMBtu), based on the per unit data provided. This requires a revision of the facility's total daily usage to 194,127 MMBtu.

Response to Comment 10a:

Staff updated **Air Quality Table 30** in the FSA. The values presented in **Air Quality Table 30** in the PSA reflected values based on the SCAQMD PDOC and the AEC revised SAFC. Staff requested clarification that the applicant concurs with the estimates provided in the SCAQMD PDOC for purposes of the environmental analysis. The applicant did not object to the usage of the values presented in the SCAQMD PDOC. The values are therefore used in the FSA..

Comment 10b:

Page 4.1-33, Air Quality Table 30 – The monthly usage for one SCTG should be 654,972 MMBtu, based on the hourly data provided. This requires a revision of the total SCTG monthly usage to 6,017,145 MMBtu and the facility's total monthly usage to 2,615,888 MMBtu.

Response to Comment 10b:

Staff requested additional information regarding this comment. The estimated monthly usage for one SCGT is based on 744 hours of operation and an hourly fuel usage of 879 MMBtu/hr. This number is multiplied by 4 to estimate the total monthly SCGT fuel usage for all 4 simple-cycle turbines. CH2M confirmed in a phone call on August 10, 2016 (CH2 2016bb) the monthly numbers were re-reviewed and determined to be correct. Therefore the comment can be disregarded.

Comment 10c:

Page 4.1-33, Air Quality Table 30 – The annual fuel usage for two combined-cycle turbine generators (CCTGs) should be 20,880,000 MMBtu, based on the per unit data provided. This requires a revision of the facility's total annual fuel usage to 29,331,552 MMBtu.

Response to Comment 10c:

Staff updated the total calculated monthly fuel usage in the FSA. Staff requested clarification that the applicant concurs with these estimates and not the estimates provided in the revised SAFC. The applicant did not object to the usage of the values presented in the SCAQMD PDOC.

Comment 11a:

Page 4.1-34, Air Quality Table 31 – Please provide the calculations for the auxiliary boiler's Maximum Daily Operation emissions (non-30-day averages), associated with Table Note a, and the Maximum Monthly Operation emissions, associated with Table Note b.

Response to Comment 11a:

Staff estimated emissions from the auxiliary boiler using both the maximum auxiliary boiler heat input and based on the reduced heat input used by SCAQMD in the PDOC. The maximum auxiliary boiler heat input emissions should be denoted by footnote a, and the reduced emissions should be denoted by footnote b. Footnotes a and b are switched in the Maximum Monthly Operations (lbs/month) Section of Table 30. The calculations follow the calculations in the SCAQMD PDOC on pages 113-115. The calculations found in the PDOC are based on reduced heat input rates found in **Air Quality Table 27** under SCAQMD emission rate. The same methodology was followed using the maximum AEC emission rates found in **Air Quality Table 27** under AEC emission rates. CH2M confirmed the numerical values did not need revising and correcting the footnotes would satisfy the request. Staff corrected the footnote in the FSA.

Comment 11b:

Page 4.1-34, Air Quality Table 31 – The SOx and PM10/2.5 Maximum Annual Operation emissions in tons per year (tpy) are swapped for the SCTG.

Response to Comment 11b:

Staff updated the **Air Quality Table 31** in the FSA.

Comment 11c:

Page 4.1-34, Air Quality Table 31 – The Maximum Monthly Operation (tons/year) header should be revised to Maximum Monthly Operation (tons/month).

Response to Comment 11c:

Staff updated the **Air Quality Table 31** in the FSA.

Comment 12:

Page 4.1-35, Air Quality Table 32 – The VOC emissions for the auxiliary boiler should be 1,223 pounds per year (lbs/year) instead of 1.223 lbs/year.

Response to Comment 12:

Staff updated **Air Quality Table 32** in the FSA.

Comment 13:

Page 4.1-40, Routine Operation Impacts – In the first bullet, it is stated "the maximum 1-hour impacts assumed that all four GE LMS-100PB were in start-up mode." Per PDOC Table 53, the 1-hour emission rates were based on one startup, one shutdown, and the balance of the hour in steady-state operation.

Response to Comment 13:

Staff included additional clarifying text in the first bullet in Routine Operation Impacts in the FSA.

Comment 14:

Page 4.1-49, Air Quality Table 41 – The minimum distance for Crystal Cove State Park should be 30.3 kilometers.

Response to Comment 14:

Staff updated **Air Quality Table 41** in the FSA.

Comment 15:

Page 4.1-51, Air Quality Table 43 – The modeled results presented in Air Quality Table 43 are identical to those presented in Air Quality Table 42, for Construction Overlap Scenario 1. The Air Quality Table 43 modeled results should be revised consistent with Table 5.1-44 of the revised SAFC, which was submitted in April 2016 (see CH2 2016s).

Response to Comment 15:

Staff updated **Air Quality Table 43** in the FSA.

Comment 16:

Page 4.1-56, Air Quality Table 45 – The Annualized Auxiliary Boiler and Oil/Water Separator Emissions (lbs/day) for SOx and PM10 should be 1.05 lbs/day and 3.73 lbs/day, respectively, based on the Maximum Annual Auxiliary Boiler and Oil/Water Separator Emissions data presented in this table, assuming operation 365 days per year.

Response to Comment 16:

Staff updated the annualized daily emissions for SOx and PM10 in **Air Quality Table 45** of the FSA.

Comment 17:

Compliance Assurance Monitoring (CAM), first paragraph – The carbon monoxide (CO) emissions for the SCTG should be 50.07 tpy, based on data presented in **Air Quality Table 32**.

Response to Comment 17:

AES proposed a lower CO limits of 2.0 ppmvd versus the 4.0 ppmvd limit included in the SAFC. The FSA emission calculations have been updated to reflect this change. The annual CO emissions have been revised to 37.47 tons per year in the FSA.

Comment 18:

Page 4.1-77, Rule 475 – The PM10 emissions for the SCTGs should be 0.005 grains per dry standard cubic foot (gr/dscf), consistent with page 149 of the PDOC (see SCAQMD 2016b).

Response to Comment 18:

Staff corrected the 8 to a 5 in the text of the FSA.

Comment 19:

Page 4.1-79, Air Quality Table 49 – The emissions presented for the proposed AEC do not match those presented in Table 45 of the PDOC (SCAQMD 2016b). Rather, the emissions presented are for the existing Alamitos Generating Station. Air Quality Table 49 should be revised as shown below. With this change, the AEC no longer exceeds the major facility threshold for PM10.

	Emissions tons/year				
	NOx	**CO**	**VOC**	**SOx**	**PM10**
Major Facility Threshold	10	50	10	100	70
Proposed AEC	137	270	68.3	10.2	69.5
Exceed Threshold	Yes	Yes	Yes	No	No

Response to Comment 19:

Air Quality Table 49 in the PSA labeled the middle row Proposed AEC. The row should have been labeled AGS. **Air Quality Table 49** was included as part of the SCAQMD rule analysis demonstration. The AGS is currently considered a major polluting facility according to the SCAQMD rules and regulations. Staff updated the **Air Quality Table 49** for consistency in the FSA.

Comment 20:

Page 4.1-96, Air Quality Table 55 – South Coast Air Quality Management District (SCAQMD) Condition C1.6, associated with Condition AQ-C4, should specify that shutdown events are limited to 13 minutes.

Response to Comment 20:

Staff corrected the shutdown event duration from 12 to 13 minutes in **Air Quality Table 55** in the FSA.

Comment 21a:

Page 4.1-97, Air Quality Table 55 – SCAQMD Condition A195.14, associated with Condition AQ-A14, should specify that the CO emission limit of 50 parts per million (ppm) is based on a correction to 3 percent oxygen.

Response to Comment 21a:

Staff corrected the oxygen percentage in the FSA.

Comment 21b:

Page 4.1-97, Air Quality Table 55 – SCAQMD Condition D12.9, associated with Condition AQ-D1, should specify a low ammonia injection rate of 44 pounds per hour, as listed in the written condition on page 4.1-124.

Response to Comment 21b:

Staff corrected the ammonia injection rate limit from 42 to 44 in the FSA.

Comment 22:

Page 4.1-98, Air Quality Table 55 – SCAQMD Condition D12.11, associated with Condition AQ-D6, should instead be referenced to SCAQMD Condition D12.14, as that is specific to the SCTG selective catalytic reduction (SCR)/CO catalyst.

Response to Comment 22:

Staff corrected the reference from D12.11 to D12.14 associated with Condition of Certification **AQ-D6** in AQ Table 55 in the FSA.

Comment 23:

Page 4.1-104, Condition AQ-SC8 – The Applicant has already purchased 5 lbs/day of VOC and PM10 ERCs and agreed to provide 1 lb/day of SOx ERCs for the AEC. Additionally, the SCAQMD is prohibited by law and regulation from issuing a Permit to Construct without satisfying the ERC surrender requirements. Therefore, the amount of ERCs should be left to the SCAQMD to satisfy local, state, and federal regulations and Condition AQ-SC8 should be revised as proposed below:

AQ-SC8 The project owner shall provide mitigation in the form of offsets or emission reduction credits (ERCs) ~~in the quantities of at least 4 lbs/day of~~ for VOC**,** ~~and 5 lbs/day of~~ PM10**, and SOx** emissions for the auxiliary boiler and ~~1 lb/day of VOC emissions for the~~ oil/water separators. The project owner shall demonstrate that the reductions are provided in the form required by the District.

~~The project owner shall provide an ERC list and surrender the ERCs as required by the District. The project owner shall~~ request ~~CPM approval for any substitutions, modifications, or additions to the ERCs.~~

~~The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.~~

Verification: The project owner shall submit ~~any project air permit and any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.~~**to the CPM records showing that the project's offset requirements have been met prior to initiating construction. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and Energy Commission docket. The CPM shall maintain an updated list of approved ERCs for the project.**[1]

Response to Comment 23:

Staff continues to include a Staff Condition detailing the amount of ERCs required and requiring the proposed ERCs be identified in the FSA. SCAQMD received an application for the additional required SOx ERCs. The SOx ERCs applications were processed and the ERCs are identified in the FDOC, allowing the public the opportunity to comment. The language of the condition in the FSA reflects the total amounts of ERCs required under CEQA. The verification language has been updated in **AQ-SC8** of the FSA.

[1] Page 4.1-104 – The "Verification" for AQ-SC8 is incorrect. It is the same as the Verification for AQ-SC5, related to notice of air permits. The Verification should be revised as set forth above.

Comment 24:

Page 4.1-107, Conditions – It is stated that "SCAQMD conditions (AQ-1 to AQ-4) apply to each unit of equipment and the AEC facility as a whole." However, there are neither SCAQMD nor CEC conditions numbered AQ-1 to AQ-4.

Response to Comment 24:

Staff updated the header in the FSA.

Comment 25:

Page 4.1-108, Condition AQ-F1 – FF11, FF12, and FF13 should be associated with Turbine Nos. SCGT-2, SCGT-3, and SCGT-4, respectively.

Response to Comment 25:

Staff updated the SCGT numbers in the FSA.

Comment 26:

Page 4.1-109, Condition AQ-F4 – The citation provided in the first sentence should be 112(r)(7).

Response to Comment 26:

Staff corrected the "l" to an "r" in the citation to Condition of Certification **AQ-F4** in the FSA.

Comment 27:

Page 4.1-117, Condition AQ-A13 – The CO limit for the SCTGs should be 4.0 parts per million by volume (ppmv), averaged over 1 hour, dry basis at 15 percent oxygen.

Response to Comment 27:

The SCAQMD imposed a more restrictive BACT limit of 2.0 ppm in the FDOC, making this comment obsolete.

Comment 28:

Page 4.1-119, Condition AQ-A17 – The ammonia (NH_3) emission limit should be corrected to 3 percent oxygen, consistent with SCAQMD Condition A195.16. This condition also makes reference to turbines, although it is only applicable to the auxiliary boiler.

Response to Comment 28:

Staff updated Condition of Certification **AQ-17** in the FSA.

Comment 29:

Page 4.1-120, Condition AQ-C1 – The start-up restrictions are not consistent with the maximum month emissions, place undue operating restrictions on the equipment without justification, and would result in the equipment being unable to respond to dispatch orders from the local balancing authority. Since the warm and hot start-up emissions and durations are identical and are in all cases less than the emissions from a cold start, there should be no restriction on hot and warm starts other than the total monthly and annual limits on any start condition. The following revisions to Condition AQ-C1 are necessary:

AQ-C1 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of cold startups shall not exceed 15 in any calendar month~~, the number of warm startups shall not exceed 12 in any calendar month, and the number of hot startups shall not exceed 35 in any calendar month~~, with no more than 2 startups in any one day.

The number of cold startups shall not exceed 80 in any calendar year~~, the number of warm startups shall not exceed 88 in any calendar year~~, and the **<u>total</u>** number of ~~hot~~ startups shall not exceed ~~332~~**<u>500</u>** in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 60 minutes. The NOx emissions from a cold startup shall not exceed 61 lbs. The CO emissions from a cold startup shall not exceed 325 lbs. The VOC emissions from a cold startup shall not exceed 36 lbs.

For the purposes of this condition, a ~~warm~~**<u>non-cold</u>** startup is defined as a startup which occurs after the combustion turbine has been shut down ~~10 hours or more but~~ less than 48 hours. A ~~warm~~**<u>non-cold</u>** startup shall not exceed 30 minutes. The NOx emissions from a ~~warm~~**<u>non-cold</u>** startup shall not exceed 17 lbs. The CO emissions from a ~~warm~~**<u>non-cold</u>** startup shall not exceed 137 lbs. The VOC emissions from a ~~warm~~**<u>non-cold</u>** startup shall not exceed 25 lbs.

~~For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 30 minutes. The NOx emissions from a hot startup shall not exceed 17 lbs. The CO emissions from a hot startup shall not exceed 137 lbs. The VOC emissions from a hot startup shall not exceed 25 lbs.~~

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted, the process will count as one startup.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

Response to Comment 30:

Staff noted the warm/hot conditions as being identical in the PSA and suggested the possibility of combining the categories. The SCAQMD agreed to language changes. The requirements were updated in the FSA.

Comment 31:

Page 4.1-133, Condition AQ-D14 – This condition requires source testing for SOx, VOC, and PM10. However, the associated SCAQMD Condition D29.6 only requires source testing for CO emissions. For consistency, the table presented in Condition AQ-D14 should be revised as shown below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment

Page 4.1-142, Condition AQ-H1 – The table in this condition should be applicable to CO, not hydrogen sulfide (H2S), consistent with SCAQMD Condition H23.7.

Response to Comment 31:

Staff corrected the H_2S to CO in the FSA.

Comment 32:

Page 4.1-142, Condition AQ-I1 – Since this condition consolidates SCAQMD Conditions I297.1 and I297.2, it should specify that the facility must hold 108,377 pounds of oxides of nitrogen (NOx) Regional Clean Air Incentives Market (RECLAIM) Trading Credits (RTCs) per turbine.

Response to Comment 32:

Condition of Certification **AQ-I1** in the PSA was applicable to both CCGTs, therefore including the total would not be appropriate. Staff added language per turbine in the FSA to make the requirements clearer.

Comment 33:

Page 4.1-142, Condition AQ-I1 – Since this condition consolidates SCAQMD Conditions I297.1 and I297.2, it should specify that the facility must hold 108,377 pounds of NOx RTCs per turbine.

Response to Comment 33:

Condition of Certification **AQ-I1** in the PSA was applicable to both CCGTs individually, therefore including the total would not be appropriate. Staff added language per turbine in the FSA to make the requirements clearer.

Comment 34:

Page 4.1-143, Condition AQ-I2 – Since this condition consolidates SCAQMD Conditions I297.3, I297.4, I297.5, and I297.6, it should specify that the facility must hold 68,575 pounds of NOx RTCs per turbine.

Response to Comment 34:

Condition of Certification **AQ-I2** in the PSA was applicable to all four SCGTs individually, therefore including the total would not be appropriate. Staff added language per turbine in the FSA to make the requirements clearer.

Comment 35:

(Please see GHG appendix for comment and response)

CONCLUSIONS

Staff offers the following conclusions regarding the SAFC to construct the AEC combined-cycle and simple-cycle units. Staff recommends the adoption of air quality conditions of certification included in the following section.

- Construction impacts would contribute to violations of the ozone, PM10, and PM2.5 ambient air quality standards. Staff recommends Conditions of Certification **AQ-SC1** to **AQ-SC5** to mitigate the construction-phase impacts of the proposed facility modifications to a less than significant level.
- Operation of the proposed facility modifications would comply with applicable SCAQMD rules and regulations, including New Source Review, BACT requirements, and offset requirements. Staff recommends the inclusion of the district's FDOC conditions as conditions of certification.
- The proposed facility would neither cause new violations of any CO, NO_2, or SO_2 ambient air quality standard nor contribute to existing violations for these pollutants. Therefore, the direct CO, NO_2, and SO_2 impacts of the proposed facility modifications are less than significant.
- The NOx and VOC emissions from the proposed facility modifications would contribute to existing violations of state and federal ozone ambient air quality standards. RTCs, VOC offsets from the district's internal bank, and VOC offsets acquired by the project owner would be used to mitigate the ozone impact to a less than a significant level.

- The PM10 and PM2.5 emissions and the PM10/PM2.5 precursor emissions from the proposed facility modifications would contribute to the existing violations of PM10 and PM2.5 ambient air quality standards. The SCAQMD would offset the PM10 emissions from its internal bank to mitigate the PM10/PM2.5 impacts of the combustion gas turbines to a less than significant level. The offsets would be in sufficient quantities to satisfy Energy Commission staff's recommendation that all nonattainment pollutant and precursor emissions be offset at least one-to-one.
- The SOx emissions from the proposed facility are considered precursor emissions to PM10/PM2.5 and could contribute to the existing violations of PM10/PM2.5 ambient air quality standards. SOx offsets from the district's internal bank, and SOx offsets acquired by the project owner, would be used to mitigate the PM10/PM2.5 impacts to a less than a significant level.
- Staff proposes Condition of Certification (**AQ-SC8**) to ensure that the emissions of the auxiliary boiler and oil/water separators would be mitigated with the quantity of SCAQMD offsets recommended by staff and to ensure agency consultation if substitutions are made to the credits.
- Implementation of the conditions of certification and the air quality conditions and practices described in the analysis would reduce potential adverse impacts to insignificant levels and ensure that the project's emissions are mitigated to less than significant.
- With the adoption of the attached conditions of certification, the AEC would comply with all applicable laws, ordinances, regulations, and standards related to air quality as described in pertinent portions of this analysis.

PROPOSED CONDITIONS OF CERTIFICATION

The air quality conditions of certification are divided into two sections; staff recommended conditions of certification and the SCAQMD FDOC conditions. Staff conditions are additional conditions of certification recommended to provide CEQA mitigation for the project. The proposed staff recommended conditions of certification are identified as the **AQ-SCx** series of conditions.

The SCAQMD has a unique system of structuring and numbering permit conditions. In order for the reader to avoid confusion between the SCAQMD numbering and Energy Commission numbering, **Air Quality Table 55** cross references the conditions in the SCAQMD FDOC to the conditions in the FSA as proposed.

Air Quality Table 55
SCAQMD Permit Conditions with Corresponding Energy Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
Facility Conditions		
F2.1	AQ-F1	Annual emission limit for PM2.5. Includes equation and emission factors. Semi-annual Title V report shall include monthly compliance demonstrations.
F9.1	AQ-F2	Exhaust opacity limits.
F18.1	AQ-F3	Acid Rain SO_2 allocations for existing boilers.
F24.1	AQ-F4	Accidental release prevention requirements. (existing)
F52.1	AQ-F5	Requires a retirement plan for the permanent shutdown of the existing boilers #1, 2, 3 and 6.
F52.2	AQ-F6	Provides specifications for SF6 circuit breakers including a maximum leakage rate 0f of 0.5 percent by weight. Requires circuit breakers to include a 10% by weight leak detections system. Leakage shall be calculated on an annual basis.
Combined-Cycle Gas Turbine Generators		
A63.2	AQ-A1	Monthly and annual contaminant emission limits (CO, VOC, PM10, & SOx).Includes emissions calculations equations and emission factors for commissioning and normal operation.
A99.1	AQ-A4	Establishes a NOx emission factor (16.66 lbs/mmscf) during the commissioning period for RECLAIM reporting. Records of natural gas are required for compliance.
A99.2	AQ-A5	Establishes a NOx emission factor (8.35 lbs/mmscf) during the interim period after commissioning but prior to CEMS certification. Records of natural gas are required for compliance.
A195.8	AQ-A9	NOx emission limit of 2.0 ppmv @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A195.9	AQ-A12	CO emission limit of 2.0 ppm @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A195.10	AQ-A15	VOC emission limit of 2.0 ppm @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A327.1	AQ-A18	Relief from emission limits, under Rule 475; project may violate either the mass emission limit or concentration emission limit, but not both at the same time.
B61.1	AQ-B1	Annual H_2S concentration limit of 0.25 grains/100 scf for natural gas.
C1.3	AQ-C1	Limits start-ups to 2 per day, 62 total per month (15 cold), and annually (80 cold,500 total). Defines cold and non-coldstarts and establishes duration and emission limits.

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
C1.4	AQ-C2	Limits shutdowns to 62 total per month and 500 annually. Limits shutdown events to 30 minutes and establishes emission limits.
D29.2	AQ-D10	Requires initial source tests for NOx, CO, SOx, VOC, PM10, PM2.5 and NH_3. Establishes testing methods and protocol requirements.
D29.3	AQ-D11	Requires source tests for specific pollutants (SOx, VOC, and PM/PM10) once every three years. Establishes testing method and reporting requirements.
D82.1	AQ-D15	Requires the installation of CEMS for CO emissions.
D82.2	AQ-D16	Requires the installation of CEMS for NOx emissions.
E73.2	AQ-E14	Requires the BACT/LAER determination to be reviewed prior to the commencement of Phase II construction (simple-cycle).
E193.4	AQ-E1	Requires that the turbines are constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
E193.5	AQ-E2	The Permit to Construct expires one year from the date of issuance unless extended. Establishes construction timelines.
E193.8	AQ-E3	Limits commissioning to 996 hours for each turbine from the date of initial start-up. Only 216 of the 996 hours can be without emission control. The equipment shall only operate when vented to the CO oxidation catalyst and SCR system after commissioning.
E193.11	AQ-E6	Requires compliance with 40 CFR 60 Subpart TTTT. Establishes a 1000 lb/MWhr (gross) CO_2 emission limit if the turbine supplies more than 1,481,141 MWh-net electrical output for distribution on a 12 operating month and 3yr average.
E193.12	AQ-E7	Requires compliance with 40 CFR 60 Subpart TTTT. Limits CO_2 emissions to 120 lbs/MMBtu if the turbine supplies less than 1,481,141 MWh-net electrical output for distribution on a 12 operating month and 3yr average.
E193.14	AQ-E9	Limits CO_2 emissions to 610,480 tons per year. Establishes a CO_2 emission rate of 937.88 lbs/gross megawatt hour on an annual basis. Includes emission equation and emission factor.
E448.1	AQ-E11	Limits total electric output from all the generators to 1094.7 MW-gross at 59 degree Fahrenheit. Establishes electrical output monitoring requirements.
I297.1, I297.2	AQ-I1	Prohibited from operation unless the project owner hold sufficient RTCs for the CTGs.
K40.4	AQ-K1	Source test reporting requirements.
Simple-Cycle Turbines		
A63.3	AQ-A2	Monthly and annual contaminant emission limits (CO, VOC, PM10, & SOx).Includes emissions calculations equations and emission factors for commissioning and normal operation.
A99.3	AQ- A6	Establishes a NOx emission factor (25.24 lbs/mmscf) during the commissioning period for RECLAIM reporting. Records of natural gas are required for compliance.

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
A99.4	AQ- A7	Establishes a NOx emission factor (11.21 lbs/mmscf) during the interim period after commissioning but prior to CEMS certification. Records of natural gas are required for compliance.
A195.11	AQ- A10	NOx emission limit of 2.5 ppm @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A195.17	AQ- A13	CO emission limit of 2.0 ppm @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A195.10	AQ- A15	VOC emission limit of 2.0 ppm @ 15% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A327.1	AQ- A18	Relief from emission limits, under Rule 475; project may violate either the mass emission limit or concentration emission limit, but not both at the same time.
B61.1	AQ-B1	Annual H_2S concentration limit of 0.25 grains/100 scf for natural gas.
C1.5	AQ-C3	Limits start-ups to 2 per day, 62 total per month, and 500 annually. Establishes duration and emission limits.
C1.6	AQ- C4	Limits shutdowns to 62 total per month and 500 annually. Limits shutdown events to 13 minutes and establishes emission limits.
D29.2	AQ-D10	Requires initial source tests for NOx, CO, SOx, VOC, PM10, PM2.5 and NH_3. Establishes testing methods and protocol requirements.
D29.3	AQ-D11	Requires source tests for specific pollutants (SOx, VOC, and PM/PM10) once every three years. Establishes testing method and reporting requirements.
D82.1	AQ-D15	Requires the installation of CEMS for CO emissions.
D82.2	AQ-D16	Requires the installation of CEMS for NOx emissions.
E193.4	AQ-E1	Requires that the turbines are constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
E193.5	AQ-E2	The Permit to Construct expires one year from the date of issuance unless extended.
E193.6	AQ-E2	The Permit to Construct is invalid if construction does not commence within 18 months after the issuance date.
E193.7	AQ-E2	The Permit to Construct is invalid if construction does not commence within 24 months after the issuance date.
E193.9	AQ-E4	Limits commissioning to 280 hours for each turbine from the date of initial start-up. Only 4 of the 280 hours can be without emission control. The equipment shall only operate when vented to the CO oxidation catalyst and SCR system after commissioning.
E193.13	AQ- E8	Requires compliance with 40 CFR 60 Subpart TTTT. Limits CO_2 emissions to 120 lbs/MMBtu..

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
E193.15	AQ- E10	Limits CO_2 emissions to 120,765 tons per year. Establishes a CO_2 emission limit of 1,356.03 lbs/gross megawatt hour on an annual basis. Includes emission equation and emission factor.
E448.1	AQ- E11	Limits total electric output from all the generators to 1094.7 MW-gross at 59 degree Fahrenheit. Establishes electrical output monitoring requirements.
I297.3-6	AQ-I2	Prohibited from operation unless the project owner hold sufficient RTCs for the simple turbines..
K40.4	AQ-K1	Source test reporting requirements.
Auxiliary Boiler		
A63.4	AQ-A3	Monthly and annual contaminant emission limits (CO, VOC, PM10, & SOx).Includes emissions calculations equations and emission factors for commissioning and normal operation.
A99.5	AQ-A8	Establishes a NOx emission factor (38.46 lbs/mmscf) during the commissioning period for RECLAIM reporting. Records of natural gas are required for compliance.
A195.13	AQ-A11	NOx emission limit of 5.0 ppm @ 3% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
A195.14	AQ-A14	CO emission limit of 50 ppm @ 3% O_2 averaged over 1-hour. Does not apply during commissioning startup, and shut down periods.
C1.7	AQ-C5	Limits start-ups to 1 per day, 10 total per month (2 cold, 4 warm, 4 hot), and annually (24 cold, 48 warm and 48 hot). Defines cold, warm and hot starts and establishes duration and emission limits.
D29.5	AQ-D13	Requires initial source tests for NOx, CO, SOx, VOC, PM10, PM2.5 and NH_3. Establishes testing methods and protocol requirements.
D29.6	AQ-D14	Requires source test for CO at full load according to testing frequency requirements in Rule 1146. Establishes testing method and reporting requirements.
D82.3	AQ-D17	Requires the installation of CEMS for NOx emissions and establishes requirements for CEMS plan.
E193.4	AQ-E1	Requires that the equipment is constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
E193.10	AQ-E5	Limits commissioning to 30 hours from the date of initial start-up. The equipment shall only operate when vented to the SCR system after commissioning.
H23.7	AQ-H1	Establishes CO requirements according to Rule 1146.
I297.7	AQ-I3	Prohibited from operation unless the project owner hold sufficient RTCs for the boiler.
K40.5	AQ-K2	Source test reporting requirements.

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
SCR/CO Catalyst for Combined-cycle		
A195.15	AQ-A16	Establishes the 5.0 ppm ammonia slip limit. Requires a NOx analyzer.
D12.9	AQ-D1	Requires a flow meter for the ammonia injection and maintain continuous record. Requires ammonia injection between 44 and 242 pounds per hour.
D12.10	AQ-D2	Requires a temperature gauge at the SCR inlet and maintain continuous record. Requires temperature be maintained between 570 and 692 degree Fahrenheit.
D12.11	AQ-D3	Requires a pressure gauge to measure the differential pressure across the SCR grid and maintain continuous record. Limits the pressure differential to 1.6 inches water column.
D29.4	AQ-D12	Requires initial, quarterly for the first year, and then annual source tests for NH_3. Establishes testing methods and protocol requirements.
E193.4	AQ-E1	Requires that the equipment is constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
SCR/CO Catalyst for Simple		
A195.15	AQ-A16	Establishes the 5.0 ppm ammonia slip limit. Requires a NOx analyzer.
D12.12	AQ-D4	Requires a flow meter for the ammonia injection and maintain continuous record. Requires ammonia injection between 110 and 180 pounds per hour.
D12.13	AQ-D5	Requires a temperature gauge at the SCR inlet and maintain continuous record. Requires temperature be maintained between 500 and 870 degrees Fahrenheit.
D12.14	AQ-D6	Requires a pressure gauge to measure the differential pressure across the SCR grid and maintain continuous record. Limits the pressure differential to 3.0 inches water column.
D29.4	AQ-D12	Requires initial, quarterly for the first year, and then annual source tests for NH_3. Establishes testing methods and protocol requirements.
E193.4	AQ-E1	Requires that the equipment is constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
SCR for the Auxiliary Boiler		
A195.16	AQ-A17	Establishes the 5.0 ppm ammonia slip limit. Requires a NOx analyzer.
D12.15	AQ-D7	Requires a flow meter for the ammonia injection and maintain continuous record. Requires ammonia injection between 0.3 and 1.1 pounds per hour.

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
D12.16	AQ-D8	Requires a temperature gauge at the SCR inlet and maintain continuous record. Requires temperature be maintained between 415 and 628 degrees Fahrenheit.
D12.17	AQ-D9	Requires a pressure gauge to measure the differential pressure across the SCR grid and maintain continuous record. Limits the pressure differential to 2.0 inches water column.
D29.4	AQ-D12	Requires initial, quarterly for the first year, and then annual source tests for NH_3. Establishes testing methods and protocol requirements.
E193.4	AQ-E1	Requires that the equipment is constructed, operated and maintained according to the mitigation measures stipulated in the Commission Decision.
Ammonia Storage Tanks		
C157.1	AQ-C6	Requires the installation of a pressure relief valve maintained at 50 psig.
E144.1	AQ-E12	Requires venting of the storage tank during filling only to the vessel from which it is being filled.
E193.4	AQ-E1	Requires that the ammonia storage tank be operated according to the mitigation measures stipulated in the Commission Decision.
Oil Water Separator		
E193.16	AQ-E13	Requires that the oil water separator be equipped with a fixed cover to minimize VOC emissions.
E193.4	AQ-E1	Requires that the oil water separator be operated according to the mitigation measures stipulated in the Commission Decision.

STAFF RECOMMENDED CONDITIONS

AQ-SC1 Air Quality Construction/Demolition Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with **AQ-SC3**, **AQ-SC4,** and **AQ-SC5** for the entire project site and linear facility construction/demolition. 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 linear facilities, and shall have the authority to stop any or all construction/demolition activities as warranted by applicable construction/demolition 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 <u>Air Quality Construction/Demolition Mitigation Plan (AQCMP)</u>: The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with AQ-SC3, AQ-SC4, and AQ-SC5.

<u>Verification</u>: At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM and the South Coast Air Quality Management District (District). The District will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 <u>Construction Fugitive Dust Control:</u> The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report (MCR) that demonstrates compliance with the following mitigation measures for the purposes of minimizing fugitive dust emissions created from construction activities and preventing all fugitive dust plumes from leaving the project site and linear facility routes. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All unpaved roads and disturbed areas in the project and linear construction sites shall be watered as frequently as necessary to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

B. No vehicle shall exceed 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.

C. Visible speed limit signs shall be posted at the construction site entrances.

D. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

E. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

F. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

G. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

H. Construction areas adjacent to any paved roadway shall be provided with sandbags or other similar measures as specified in the Storm Water Pollution Prevention Plan (SWPP) to prevent run-off to roadways.

I. All paved roads within the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

J. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public roadways.

K. All soil storage piles and disturbed areas that remain inactive for longer than ten days shall be covered, or shall be treated with appropriate dust suppressant compounds.

L. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

M. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall 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.

N. Disturbed areas will be re-vegetated as soon as practical.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report (MCR) to include:

1. A summary of all actions taken to maintain compliance with this condition;
2. Copies of any complaints filed with the District in relation to project construction; and
3. Any other documentation deemed necessary by the CPM, District or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported**:** (1) off the project site**,** (2) 200 feet beyond the centerline of the construction of linear facilities**,** or (3) within 100 feet upwind of any regularly occupied structures not owned by the project owner indicate that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if step 1 specified above fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, provided that the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

Verification: The AQCMM shall provide the CPM a MCR to include:

1. A summary of all actions taken to maintain compliance with this condition;
2. Copies of any complaints filed with the District in relation to project construction; and
3. Any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the MCR, a construction mitigation report that demonstrates compliance with the following mitigation measures for purposes of controlling diesel construction-related emissions. Any deviation from the following mitigation measures shall require prior CPM notification and approval.

A. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

B. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 4 or 4i California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless a good faith effort to the satisfaction of the CPM that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. This good faith effort shall be documented with signed written correspondence by the appropriate construction contractors along with documented correspondence with at least two construction equipment rental firms. In the event that a Tier 4 or 4i engine is not available for any off-road equipment larger than 50 hp, that equipment shall be equipped with a Tier 3 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NOx) and diesel particulate matter (DPM) to no more than Tier 3 levels unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" for the following, as well as other, reasons.

   1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question to Tier 3 equivalent emission levels and the highest level of available control using retrofit or Tier 2 engines is being used for the engine in question; or

   2. The construction equipment is intended to be on site for 10 working days or less.

   3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not practical.

C. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and that a replacement for the equipment item in question meeting the controls required in item "B" occurs within 10 days of termination of the use, if the equipment would be needed to continue working at this site for more than 15 days after the use of the retrofit control device is terminated, if one of the following conditions exists :

   1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.

   2. The retrofit control device is causing or is reasonably expected to cause engine damage.

   3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.

4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

D. All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (B) above shall be properly maintained and the engines tuned to the engine manufacturer's specifications.

E. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

F. Construction equipment will employ electric motors when feasible.

Verification*:* The AQCMM shall include in a table in the MCR the following to demonstrate control of diesel construction-related emissions:

1. A summary of all actions taken to maintain compliance with this condition,

2. A list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained, and

3. Any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall provide the CPM copies of any District-issued project air permit for the facility. The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. EPA, and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any project air permit and any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC7 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter that include operational and emissions information as necessary to demonstrate compliance with the Conditions of Certification herein. The Quarterly Operation Report will specifically state that the facility meets all applicable Conditions of Certification or note or highlight all incidences of noncompliance.

Verification: The project owner shall submit the Quarterly Operation Reports to the CPM and District, if requested by the District, no later than 30 days following the end of each calendar quarter.

AQ-SC8 The project owner shall provide mitigation in the form of offsets or emission reduction credits (ERCs) in the quantities of at least 4.08 lbs/day of VOC,1.27 lbs per day of SOx, and 4.54 lbs/day of PM10 emissions for the auxiliary boiler and 1 lb/day of VOC emissions for the oil/water separators. The project owner shall demonstrate that the reductions are provided in the form required by the District.

The project owner shall provide an ERC list and surrender the ERCs as required by the District. The project owner shall request CPM approval for any substitutions, modifications, or additions to the ERCs.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, and that the requested change(s) will not cause the project to result in a significant environmental impact. The District must also confirm that each requested change is consistent with applicable federal and state laws and regulations.

Verification: The project owner shall submit any project air permit and any proposed air permit modification to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt, including records showing that the project's offset requirements have been met prior to initiating construction. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and Energy Commission docket. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC9 The project owner shall complete the auxiliary boiler commissioning prior to the commissioning of the combined-cycle gas turbines (CCGT-1 and CCGT-2).

Verification: The project owner shall identify the start and conclusion of the work phases described above in the Monthly Compliance Reports and/or Quarterly Operational reports.

AQ-SC10 The project owner shall complete the combined-cycle turbine (CCGT-1 and CCGT-2) commissioning prior to the commissioning of the simple-cycle gas turbines (SCGT-1, SCGT-2, SCGT-3 and SCGT-4).

Verification: The project owner shall identify the start and conclusion of the work phases described above in the Monthly Compliance Reports and/or Quarterly Operational reports.

AQ-SC11 The project owner shall comply with all staff (AQ SC) and district (AQ) Conditions of Certification. The CPM, in consultation with the District, may approve any change to a Condition of Certification regarding air quality, as a staff approved modification, provided that: (1) the Project remains in compliance with all applicable laws, ordinances, regulations, and standards, (2) the requested change clearly will not cause the Project to result in a significant environmental impact, (3) no additional mitigation or offsets will be required as a result of the change, (4) no existing daily, quarterly, or annual permit limit will be exceeded as a result of the change, and (5) no increase in any daily, quarterly, or annual permit limit will be necessary as a result of the change.

Verification: The project owner shall submit a petition to amend for any proposed change to a condition of certification pursuant to this condition and shall provide the CPM with any additional information the CPM requests to substantiate the basis for approval.

DISTRICT'S PERMITTED EQUIPMENT AND CONDITIONS

Equipment

ID No.	Equipment Descriptions
	AEC CCGT Power Block
Combined-cycle Gas Turbine 1 (CCGT-1)	
D165	CCGT-1 General Electric Model 7FA.05, natural gas combined-cycle, 236.645 MW at 28 degrees Fahrenheit, with a Heat Recovery Steam Generator and 219.615 MW Steam Turbine Generator (common with HRSG CCGT-2)
C169	CCGT-1 CO Oxidation Catalyst
C170	CCGT-1 Selective Catalytic Reduction with aqueous ammonia
S172	CCGT-1 Turbine Stack, height of 140 feet and diameter of 20 feet
Combined-cycle Gas Turbine 2 (CCGT-2)	
D173	CCGT-2 General Electric Model 7FA.05, natural gas combined-cycle, 236.645 MW at 28 degrees Fahrenheit, with a Heat Recovery Steam Generator and 219.615 MW Steam Turbine Generator (common with HRSG CCGT-1)
C177	CCGT-2 CO Oxidation Catalyst
C178	CCGT-2 Selective Catalytic Reduction with aqueous ammonia
S180	CCGT-2 Turbine Stack, height of 140 feet and diameter of 20 feet
Auxiliary Boiler	
D181	70.8 MMBtu/hr Babcock and Wilcox Model FM 103-88 natural gas boiler
C183	Auxiliary Boiler Selective Catalytic Reduction with aqueous ammonia
S211	Auxiliary Boiler Stack, height of 80 feet and diameter of 3 feet
	AEC SCGT Power Block
Simple Gas Turbine 1 (SCGT-1)	
D185	SCGT-1 General Electric Model LMS-100PB, natural gas simple-cycle, 100.438 MW at 59 degrees Fahrenheit
C187	SCGT-1 CO Oxidation Catalyst
C188	SCGT-1 Selective Catalytic Reduction with aqueous ammonia
S180	SCGT-1 Turbine Stack, height of 80 feet and diameter of 13.5 feet
Simple Gas Turbine 2 (SCGT-2)	
D191	SCGT-2 General Electric Model LMS-100PB, natural gas simple-cycle, 100.438 MW at 59 degrees Fahrenheit
C193	SCGT-2 CO Oxidation Catalyst
C194	SCGT-2 Selective Catalytic Reduction with aqueous ammonia

ID No.	Equipment Descriptions
S196	SCGT-2 Turbine Stack, height of 80 feet and diameter of 13.5 feet
Simple Gas Turbine 3 (SCGT-3)	
D197	SCGT-3 General Electric Model LMS-100PB, natural gas simple-cycle, 100.438 MW at 59 degrees Fahrenheit
C199	SCGT-3 CO Oxidation Catalyst
C200	SCGT-3 Selective Catalytic Reduction with aqueous ammonia
S202	SCGT-3 Turbine Stack, height of 80 feet and diameter of 13.5 feet
Simple Gas Turbine 4 (SCGT-4)	
D203	SCGT-1 General Electric Model LMS-100PB, natural gas simple-cycle, 100.438 MW at 59 degrees Fahrenheit
C205	SCGT-1 CO Oxidation Catalyst
C206	SCGT-1 Selective Catalytic Reduction with aqueous ammonia
S208	SCGT-1 Turbine Stack, height of 80 feet and diameter of 13.5 feet
Supporting Equipment	
Oil/Water Separation	
D209	OWS-1 Storage Tank, 5,000 gallon serving CCGT
D210	OWS-2 Storage Tank, 5,000 gallon serving SCGT
Inorganic Chemical Storage	
D163	Tank-1 Storage Tank 40,000 gallons serving the CCGT
D164	Tank-2 Storage Tank 40,000 gallons serving the SCGT

The following conditions were developed by the SCAQMD and are obtained from the FDOC.

The following SCAQMD-conditions AQ-F1 to AQ-F6 are facility wide conditions that apply to each unit of equipment and the AEC facility as a whole.

AQ-F1 The project owner shall limit emissions from this facility as follows:

CONTAMINANT	EMISSIONS LIMIT
PM 2.5	Less than 100 tons in any one year

The project owner shall not operate any of the Boilers Nos. 1, 2, 3, 4, 5, 6 (Devices D39, D42, D45, D48, D51, D3, respectively), Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 **(**Devices D165 and D173, respectively), Auxiliary Boiler (Device D181), or Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) unless compliance with the annual emission limit for PM2.5 is demonstrated.

Compliance with the annual emission limit shall be based on a 12-month rolling average basis. The project owner shall calculate the PM2.5 emissions for the facility by summing the PM2.5 emissions for each of the sources by using the equation below.

Facility PM2.5, tons/year = (FF1*EF1 + FF2*EF2 + FF3*EF3 + FF4*EF4 + FF5*EF5 + FF6*EF6 + FF7*EF7 + FF8*EF8 + FF9*EF9 + FF10*EF10 + FF11*EF11+ FF12*EF12 + FF13*EF13)/2000

Equipment Monthly Fuel Usage (mmscf))	Emission Factor (lb/mmscf)
Existing Boilers	
FF1 = Boiler No. 1	EF1 = 1.19
FF2 = Boiler No. 2	EF2 = 1.19
FF3 = Boiler No. 3	EF3 = 1.19
FF4 = Boiler No. 4	EF4 = 1.19
FF5 = Boiler No. 5	EF5 = 1.19
FF6 = Boiler No. 6	EF6 = 1.19
Combined-Cycle Turbines	
FF7 = No. CCGT-1	EF7 = 3.92
FF8 = No. CCGT-2	EF8 = 3.92
Auxiliary Boiler	
FF9 = Auxiliary Boiler	EF9 = 7.42
Simple-Cycle Turbines	
FF10 = Turbine No. SCGT-1	EF10 = 7.44
FF11 = Turbine No. SCGT-2	EF11 = 7.44
FF12 = Turbine No. SCGT-3	EF12 = 7.44
FF13 = Turbine No. SCGT-4	EF13 = 7.44

Any changes to these emission factors must be approved in advance by the SCAQMD in writing and be based on unit specific source tests performed using SCAQMD-approved testing protocol.

AES Alamitos, LLC shall submit written reports of the monthly PM2.5 compliance demonstration required by this condition. The report submittal shall be included with the semi-annual Title V report as required under Rule 3004(a)(4)(f). Records of the monthly PM2.5 compliance demonstration shall be maintained on site for at least five years and made available upon SCAQMD request.

For the purpose of this condition, any one year shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12-month period beginning on the first day of each calendar month.

[Rule 1325]

Verification: The project owner shall submit to the CPM the facility annual operating and emissions data demonstrating compliance with this condition as part of the fourth quarter Quarterly Operation Report (**AQ-SC7**).

AQ-F2 Except for open abrasive blasting operations, the project owner shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

a) As dark or darker in shade as that designated No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401]

Verification: The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (ARB), the United States Environmental Protection Agency (U.S. EPA) and the California Energy Commission (Energy Commission).

AQ-F3 Acid Rain SO_2 Allowance Allocations for affected units are as follows:

Device ID	Boiler ID	Contaminant	Tons in any year
39	Unit 1	SO_2	2,703
42	Unit 2	SO_2	17
45	Unit 3	SO_2	81
48	Unit 4	SO_2	541
51	Unit 5	SO_2	3,866
3	Unit 6	SO_2	936

a) The allowance allocations shall apply to calendar years 2010 and beyond.

b) The number of allowances allocated to Phase II affected units by U.S. EPA may change in a 1998 revision to 40 CFR73 Tables 2, 3 and 4. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocation identified in this permit (see 40 CFR 72.84)

[40 CFR 73 Subpart B]

Verification: The project owner shall submit to the CPM the statement certifying compliance with this condition as part of the fourth quarter Quarterly Operation Report (**AQ-SC7**).

AQ-F4 Accidental release prevention requirements of Section 112(r)(7):

a) The project owner shall comply with the accidental release prevention requirements pursuant to 40 CFR Part 68 and shall submit to the Executive Officer, as a part of an annual compliance certification, a statement that certifies compliance with all of the requirements of 40 CFR Part 68, including the registration and submission of a risk management plan (RMP).

b) The project owner shall submit any additional relevant information requested by the Executive Officer or designated agency.

[RULE 40 CFR 68 – Accidental Release Prevention, 5-24-1996].

Note: This condition is applicable to the four existing ammonia tanks (Devices D19, D151, D152, and D153) in Section D, because they are permitted to contain 29% aqueous ammonia. This condition is not applicable to the two new ammonia tanks (Devices D163, D164) installed for the AEC project because they are permitted to contain 19% ammonia. Ongoing compliance with this condition will not be required after the four existing tanks are removed from the facility.

Verification: The project owner shall submit to the CPM the statement certifying compliance with this condition as part of the fourth quarter Quarterly Operation Report (**AQ-SC7**).

AQ-F5 To utilize SCAQMD Rule 1304, the project owner shall perform the following as set forth in SCAQMD permit condition F 52.1:

The facility shall submit a detailed retirement plan for the permanent shutdown of Boilers Nos. 1, 2, 6 and 3 (Devices D39, D42, D3, and D45, respectively), describing in detail the steps and schedule that will be taken to render Boilers Nos. 1, 2, 6, and 3 permanently inoperable.

The retirement plan shall be submitted to SCAQMD within 60 days after Permits to Construct for Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Devices D185, D191, D197, and D203 respectively) are issued.

AES shall not commence any construction of the Alamitos Energy Project including Gas Turbines Nos. CCGT-1, CCGT-2, SCGT-1, SCGT-2, SCGT-3, and SCGT-4, unless the retirement plan is approved in writing by SCAQMD. If SCAQMD notifies AES that the plan is not approvable, AES shall submit a revised plan addressing SCAQMD's concerns within 30 days.

Within 30 calendar days of actual shutdown but no later than December 29, 2019, AES shall provide SCAQMD with a notarized statement that Boilers Nos. 1, 2, and 6 are permanently shut down and that any re-start or operation of the boilers shall require new Permits to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boilers Nos. 1, 2, and 6, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 29, 2019.

AES shall cease operation of Boilers Nos. 1, 2, and 6 within 90 calendar days of the first fire of Gas Turbines No. CCGT-1 or CCGT-2, or by December 29, 2019 whichever is earlier.

Within 30 calendar days of actual shutdown but no later than December 31, 2020, AES shall provide SCAQMD with a notarized statement that Boiler No. 3 is permanently shut down and that any re-start or operation of the boiler shall require a new Permit to Construct and be subject to all requirements of Nonattainment New Source Review and the Prevention Of Significant Deterioration Program.

AES shall notify SCAQMD 30 days prior to the implementation of the approved retirement plan for permanent shutdown of Boiler No. 3, or advise SCAQMD as soon as practicable should AES undertake permanent shutdown prior to December 31, 2020.

AES shall cease operation of Boiler No. 3 within 90 calendar days of the first fire of Gas Turbines No. SCGT-1, SCGT-2, SCGT-3, or SCGT-4, or by December 31, 2020, whichever is earliest.

[RULE 1304(a)—Modeling and Offset Exemption; RULE 1313(d)]

Verification: The project owner shall submit the retirement plan, and any modifications to the plan, to the CPM for approval within five working days of submittal to the SCAQMD. The project owner shall submit the written proof of SCAQMD approval of the retirement plan or any modification to the retirement plan within five working days of obtaining SCAQMD written approval. The project owner shall submit to the CPM the notarized station that Boilers 1, 2, and 6 are permanently shut down within 30 days of actual shutdown but no later than December 29, 2019. The project owner shall submit to the CPM the notarized station that Boiler 3 is permanently shut down within 30 days of actual shutdown but no later than December 31, 2020.

AQ-F6 The project owner is subject to the applicable requirements of the following rules or regulations(s):

For all circuit breakers at the facility utilizing SF6, including the circuit breakers serving Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2; common Steam Turbine Generator; and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4, the project owner shall install, operate, and maintain enclosed-pressure SF6 circuit breakers with a maximum annual leakage rate of 0.5 percent by weight. The circuit breakers shall be equipped with a 10 percent by weight leak detection system.

The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.

The total CO_2e emissions from all circuit breakers shall not exceed 74.55 tons per calendar year.

The project owner shall calculate the SF6 emissions due to leakage from the circuit breakers by using the mass balance in equation DD-1 at 40 CFR Part 98, Subpart DD, on an annual basis.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

Device Conditions

Emission Limits:

AQ-A1 The project owner shall limit emissions from this equipment as follows:

Contaminant	Range	Emissions Limit
Monthly Pounds in Any Calendar Month (lbs/month)		
CO	Less than or equal to	95,023 lbs/month
VOC	Less than or equal to	13,314 lbs/month
PM10	Less than or equal to	6,324 lbs/month
Sox	Less than or equal to	3,616 lbs/month
Annual Pounds in Any One Year (lbs/year)		
CO	Less than or equal to	180,544 (lbs./year)
VOC	Less than or equal to	52,668 (lbs./year)
PM10	Less than or equal to	39,440 (lbs./year)
Sox	Less than or equal to	7,435 (lbs./year)

For the purposes of this condition, the above emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The SCAQMD shall be notified in writing once the commissioning process for each turbine is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

The project owner shall calculate the monthly emissions for CO, VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in million standard cubic feet per month (mmscf/month)) * (Emission factors indicated below)

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

For commissioning, the emission factors shall be as follows: CO, 61.18 lb/mmscf; VOC, 8.86 lb/mmscf; PM10, 5.11 lb/mmscf; and SOx, 2.92 lb/mmscf.

For normal operation, the emission factors shall be as follows: CO, 15.28 lb/mmscf; VOC, 4.70 lb/mmscf; PM10, 3.92 lb/mmscf; and SOx, 2.24 lb/mmscf.

For a month during which both commissioning and normal operation take place the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

Compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.75 lb/mmscf.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[RULE 1303(a)(1)-BACT; RULE 1304.1, RULE 1703(a)(2) – PSD-BACT]
[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall provide emissions summary data in compliance with his condition as part of the Quarterly Operation reports (**AQ-SC7**).

AQ-A2 The project owner shall limit emissions from this equipment as follows:

Contaminant	Range	Emissions Limit
Monthly Pounds in Any Calendar Month (lbs/month)		
CO	Less than or equal to	8,594 lbs/month
VOC	Less than or equal to	1,973 lbs/month
PM10	Less than or equal to	4,638 lbs/month
SOx	Less than or equal to	1,207 lbs/month
Annual Pounds in Any One Year (lbs/year)		
CO	Less than or equal to	29,730 (lbs./year)
VOC	Less than or equal to	7,500 (lbs./year)
PM10	Less than or equal to	14,695 (lbs./year)
SOx	Less than or equal to	1,275 (lbs./year)

For the purposes of this condition, the above emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The SCAQMD shall be notified in writing once the commissioning process for each turbine is completed.

Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

The project owner shall calculate the monthly emissions for CO, VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month =

(Monthly fuel usage in million standard cubic feet per month (mmscf/month)) * (Emission factors indicated below)

The following emission factors shall be used to demonstrate compliance with the monthly emission limits.

For commissioning, the emission factors shall be as follows: CO, 112.03 lb/mmscf; VOC, 3.69 lb/mmscf; PM10, 2.00 lb/mmscf; and SOx, 7.69 lb/mmscf.

For normal operation, the emission factors shall be as follows: CO, 8.84 lb/mmscf; VOC, 3.17 lb/mmscf; PM10, 7.44 lb/mmscf; and SOx, 1.94 lb/mmscf.

For a month during which both commissioning and normal operation take place the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

Compliance with the annual emission limits shall be based on a 12-operating month-rolling-average basis, following completion of the commissioning period.

The emission factors for the monthly emission limits shall be the same as the emission factors used to demonstrate compliance with the annual emission limits, except the annual emission factor for SOx is 0.65 lb/mmscf.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[RULE 1303(a)(1)-BACT; RULE 1304.1, RULE 1703(a)(2) – PSD-BACT]
[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall provide emissions summary data in compliance with his condition as part of the Quarterly Operation reports (**AQ-SC7**).

AQ-A3 The project owner shall limit emissions from this equipment as follows:

Contaminant	Range	Emissions Limit
Monthly Pounds in Any Calendar Month (lbs/month)		
CO	Less than or equal to	605 lbs/month
VOC	Less than or equal to	102 lbs/month
PM10	Less than or equal to	113.5 lbs/month
Sox	Less than or equal to	32 lbs/month

The project owner shall calculate the monthly emissions for CO, VOC, PM10, and SOx using the equation below.

Monthly Emissions, lb/month = (Monthly fuel usage in mmscf/month) * (Emission factors indicated below)

For commissioning and normal operation, the emission factors shall be as follows: CO, 39.55 lb/mmcf; VOC, 6.67 lb/mmcf; PM10, 7.42 lb/mmcf; and SOx, 2.08 lb/mmcf.

The project owner shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, natural gas usage in a calendar month.

[RULE 1303(a)(1)-BACT, RULE 1303(b)(2)-Offset, RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall provide emissions summary data in compliance with his condition as part of the Quarterly Operation reports (**AQ-SC7**).

AQ-A4 The project owner shall limit NOx emissions to 16.66 lbs/mmscf only during the turbine commissioning period to report RECLAIM emissions, not to exceed one year after the start of unit operations.

The project owner shall maintain records of natural gas usage for this period.

[RULE 2012]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall provide natural gas usage records for the turbines as part of the Quarterly Operation reports (**AQ-SC7**). The records shall identify the usage on a per turbine basis and clearly identify the corresponding commissioning project period.

AQ-A5 The project owner shall limit NOx emissions to 8.35 lbs/mmscf only during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operations.

The project owner shall maintain records of natural gas usage for this period.

[RULE 2012]
[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall provide natural gas usage records for the turbines as part of the Quarterly Operation reports (**AQ-SC7**). The records shall identify the usage on a per turbine basis and clearly identify the corresponding post-commissioning, pre-CEMS project period.

AQ-A6 The project owner shall limit NOx emissions to 25.24 lbs/mmscf only during the turbine commissioning period to report RECLAIM emissions, not to exceed one year after the start of unit operations.

The project owner shall maintain records of natural gas usage for this period.

[RULE 2012]
[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall provide natural gas usage records for the turbines as part of the Quarterly Operation reports (**AQ-SC7**). The records shall identify the usage on a per turbine basis and clearly identify the corresponding commissioning project period.

AQ-A7 The project owner shall limit NOx emissions to 11.21 lbs/mmscf only during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after start of unit operations.

The project owner shall maintain records of natural gas usage for this period.

[RULE 2012]
[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall provide natural gas usage records for the turbines as part of the Quarterly Operation reports (**AQ-SC7**). The records shall identify the usage on a per turbine basis and clearly identify the corresponding commissioning project period.

AQ-A8 The project owner shall limit NOx emissions to 38.46 lbs/mmscf only during the interim period after commissioning but prior to CEMS certification to report RECLAIM emissions, not to exceed one year after the start of unit operations.

The project owner shall maintain records of natural gas usage for this period.

[RULE 2012]
[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall provide natural gas usage records for the auxiliary boiler as part of the Quarterly Operation reports (**AQ-SC7**). The records shall clearly identify the corresponding commissioning project period.

AQ-A9 The project owner shall limit NOx emissions to 2.0 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[RULE 1703(a)(2) – PSD-BACT; RULE 2005]
[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A10 The project owner shall limit NOx emissions to 2.5 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[RULE 1703(a)(2) – PSD-BACT; RULE 2005]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A11 The project owner shall limit NOx emissions to 5 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup periods.

[RULE 1703(a)(2) – PSD-BACT; RULE 2005]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A12 The project owner shall limit CO emissions to 1.5parts per million by volume (PPMV), averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[RULE 1303(a)(1)-BACT; RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A13 The project owner shall limit CO emissions to 2.0 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[RULE 1303(a)(1)-BACT; RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A14 The project owner shall limit CO emissions to 50 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 3 percent oxygen. This limit shall not apply to boiler commissioning and startup.

[RULE 1303(a)(1)-BACT; RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall submit CEMS records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A15 The project owner shall limit VOC emissions to 2.0 parts per million by volume (PPMV), averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[RULE 1303(a)(1)-BACT; RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit records demonstrating compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A16 The 5.0 PPMV NH_3 emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.

The project owner shall calculate and continuously record the NH_3 slip concentration using the following equation:

NH_3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

a = NH_3 injection rate (lb/hr)/17(lb/lb-mol)

b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The project owner shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The project owner shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the turbine.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[RULE 1303(a)(1)-BACT]

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle)]

Verification: The project owner shall install, calibrate, maintain, and the monitoring system according to a District-approved monitoring plan. Prior to the installation the project owner shall submit a monitoring plan to the CPM for review and approval. The project owner shall include exceedances of the hourly ammonia slip limit and calibration reports as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A17 The 5.0 PPMV NH_3 emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.

The project owner shall calculate and continuously record the NH_3 slip concentration using the following equation:

NH_3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b, where:

a = NH_3 injection rate (lb/hr)/17(lb/lb-mol)

b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The project owner shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The project owner shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the auxiliary boiler.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

[RULE 1303(a)(1)-BACT]

[Devices subject to this condition: C183 (auxiliary boiler)]

Verification: The project owner shall install, calibrate, maintain, and the monitoring system according to a District-approved monitoring plan. Prior to the installation the project owner shall submit a monitoring plan to the CPM for review and approval. The project owner shall include exceedances of the hourly ammonia slip limit and calibration reports as part of the Quarterly Operation Reports (**AQ-SC7**).

AQ-A18 The project owner shall limit PM10 emissions to 0.01 grain per standard cubic feet (grains/scf) or 11 pounds per hour (lbs/hr). For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[RULE 475]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (AQ-SC8). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Material/Fuel Type limits

AQ-B1 The project owner shall not use natural gas containing the following specified compounds:

Compound	Range	Emissions Limit
H_2S	Greater than	0.25 grain/100scf

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H_2S.

[RULE 1303(a)(1)-BACT]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall include documentation demonstrating compliance as part of the Quarterly Operation Reports (**AQ-SC8**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Operating Parameters

AQ-C1 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of cold startups shall not exceed 15 in any calendar month, with no more than 2 startups in any one day.

The number of cold startups shall not exceed 80 in any calendar year, and the total number of startups shall not exceed 500 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 60 minutes. The NOx emissions from a cold startup shall not exceed 61 lbs. The CO emissions from a cold startup shall not exceed 325 lbs. The VOC emissions from a cold startup shall not exceed 36 lbs.

For the purposes of this condition, a non-cold startup is defined as a startup which occurs after the combustion turbine has been shut down less than 48 hours. A non-cold startup shall not exceed 30 minutes. The NOx emissions from a non-cold startup shall not exceed 17 lbs. The CO emissions from a non-cold startup shall not exceed 137 lbs. The VOC emissions from a non-cold startup shall not exceed 25 lbs.

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table documenting the type of startup, duration and date of occurrence.

AQ-C2 The project owner shall limit the number of shutdowns to no more than 62 in any one calendar month.

The number of shutdowns shall not exceed 500 in any calendar year.

Each shutdown shall not exceed 30 minutes. The NOx emissions from a shutdown event shall not exceed 10 lbs. The CO emissions from a shutdown event shall not exceed 133 lbs. The VOC emissions from a shutdown event shall not exceed 32 lbs.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table documenting each shutdown, and indicating the duration and date of occurrence.

AQ-C3 The project owner shall limit the number of start-ups to no more than 62 in any one calendar month.

The number of startups shall not exceed 2 startups in any one day. The number of startups shall not exceed 500 in any calendar year.

A startup shall not exceed 30 minutes. The NOx emissions from a startup shall not exceed 16.6 lbs. The CO emissions from a startup shall not exceed 15.4 lbs. The VOC emissions from a startup shall not exceed 2.80 lbs.

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table documenting the type of startup, duration and date of occurrence.

AQ-C4 The project owner shall limit the number of shutdowns to no more than 62 in any one calendar month.

The number of shutdowns shall not exceed 500 in any calendar year.

Each shutdown shall not exceed 13 minutes. The NOx emissions from a shutdown event shall not exceed 3.12 lbs. The CO emissions from a shutdown event shall not exceed 28.1 lbs. The VOC emissions from a shutdown event shall not exceed 3.06 lbs.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table documenting each shutdown, and indicating the duration and date of occurrence.

AQ-C5 The project owner shall limit the number of start-ups to no more than 10 in any one calendar month.

The number of cold startups shall not exceed 2 in any calendar month, the number of warm startups shall not exceed 4 in any calendar month, and the number of hot starts shall not exceed 4 in any calendar month, with no more than 1 startup in any one day.

The number of cold startups shall not exceed 24 in any calendar year, the number of warm startups shall not exceed 48 in any calendar year, and the number of hot startups shall not exceed 48 in any calendar year.

For the purposes of this condition, a cold startup is defined as a startup which occurs after the combustion turbine has been shut down for 48 hours or more. A cold startup shall not exceed 170 minutes. The NOx emissions from a cold startup shall not exceed 4.22 lbs.

For the purposes of this condition, a warm startup is defined as a startup which occurs after the combustion turbine has been shut down 10 hours or more but less than 48 hours. A warm startup shall not exceed 85 minutes. The NOx emissions from a warm startup shall not exceed 2.11 lbs.

For the purposes of this condition, a hot startup is defined as a startup which occurs after the steam turbine has been shut down for less than 10 hours. A hot startup shall not exceed 25 minutes. The NOx emissions from a hot startup shall not exceed 0.62 lbs.

The project owner shall maintain records in a manner approved by the District, to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table indicating documenting type of startup, duration and date of occurrence.

AQ-C6 The project owner shall install and maintain a pressure relief valve set at 50 psig.

[RULE 1303(a)(1)-BACT, RULE 1303(a)(1)-BACT]

[Devices subject to this condition: D163, D164 (ammonia tank)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall provide records including a table indicating documenting type of startup, duration and date of occurrence.

Monitoring/Tesing Parameters

AQ-D1 The project owner shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The project owner shall maintain the ammonia injection rate between 44 and 242 pounds per hour, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C170, C178 (combined-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D2 The project owner shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 570 degrees Fahrenheit and 692 degrees Fahrenheit, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C170, C178 (combined-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D3 The project owner shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall not exceed 1.6 inches water column.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C170, C178 (combined-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D4 The project owner shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The project owner shall maintain the ammonia injection rate between 110 and 180 pounds per hour, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C188, C194, C200, C206 (simple-cycle)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D5 The project owner shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 500 degrees Fahrenheit and 870 degrees Fahrenheit, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C188, C194, C200, C206 (simple-cycle)]

__**Verification:**__ The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D6 The project owner shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall not exceed 3.0 inches water column.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C188, C194, C200, C206 (simple-cycle)]

__**Verification:**__ The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D7 The project owner shall install and maintain a flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH_3).

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The flow meter shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The project owner shall maintain the ammonia injection rate between 0.3 and 1.1 pounds per hour.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C183 (auxiliary boiler)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D8 The project owner shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The temperature gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 415 degrees Fahrenheit and 628 degrees Fahrenheit, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C183 (auxiliary boiler)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D9 The project owner shall install and maintain a pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The project owner shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

The pressure gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure differential shall not exceed 2.0 inches water column.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: C183 (auxiliary boiler)]

Verification: The project owner shall demonstrate compliance with this condition as part of the Quarterly Operation Reports (**AQ-SC7**). The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D10 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be Tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	District Approved Averaging Time	Fuel Sample
VOC emissions	District Method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A / District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	EPA Method 201A / 202	District-Approved Averaging Time	Outlet of the SCR serving this equipment
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, the combined-cycle turbine and steam turbine generating output in MW-gross and MW-net, and the simple-cycle turbine generating output in MW-gross and MW-net.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences.

The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The sampling time for PM and PM2.5 tests shall be 4 hours or longer as necessary to obtain a measureable amount of sample.

The tests shall be conducted when the combined-cycle turbine is operating at loads of 45, 75, and 100 percent of maximum load, and the simple-cycle turbine is operating at loads of 50, 75, and 100 percent of maximum load.

For natural gas fired turbines only, for the purpose of demonstrating compliance with VOC BACT limits as determined by SCAQMD, the operator shall use SCAQMD Method 25.3 modified as follows:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters per the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

The use of this modified method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon for natural gas fired turbines.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit the proposed protocol for the initial source tests no later than 90 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test of the date and time of the scheduled test.

AQ-D11 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be Tested	Required Test Method(s)	Averaging Time	Test Location
SOx emissions	AQMD Laboratory Method 307-91	District Approved Averaging Time	Fuel Sample
VOC emissions	District Method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A / District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment

The test(s) shall be conducted at least once every three years.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

For natural gas fired turbines only, for the purpose of demonstrating compliance with VOC BACT limits, as determined by SCAQMD, the operator shall use Method 25.3 modified as follows:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters per the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F.

The use of this modified method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon for natural gas fired turbines.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall test according to the original protocol. If changes to the testing methods or testing conditions are proposed then the project owner shall submit a revised protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit the source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test of the date and time of the scheduled test.

AQ-D12 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be Tested	Required Test Method(s)	Averaging Time	Test Location
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT]

[Devices subject to this condition: C170, C178 (combined-cycle), C188, C194, C200, C206 (simple-cycle), C183 (auxiliary boiler)]

Verification: The project owner shall test according to the original protocol. If changes to the testing methods or testing conditions are proposed then the project owner shall submit a revised protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit the source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test of the date and time of the scheduled test.

AQ-D13 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be Tested	Required Test Method(s)	Averaging Time	Test Location
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	NA	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A / District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	EPA Method 201A / 202	District-Approved Averaging Time	Outlet of the SCR serving this equipment
NH_3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. The District shall be notified of the date and time of the test at least 10 days prior to the test.

For each firing rate, the following operating data shall be included: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees Fahrenheit, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences.

The test protocol shall include the identity of the testing lab, confirmation that the test lab is approved under the District Laboratory Approval Program for the required test method for the CO pollutant, a statement from the testing lab certifying that it meets the criteria of Rule 304 (no conflict of interest), and a description of all sampling and analytical procedures.

The sampling facilities shall comply with the District Guidelines for Construction of Sampling and Testing Facilities, pursuant to Rule 217.

The sampling time for the PM and PM2.5 tests shall be 1 hour or longer as necessary to obtain a measureable amount of sample.

The test shall be conducted when this equipment is operating at maximum, minimum, and normal operating rates.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, ARB, and SCAQMD.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall submit the proposed protocol for the initial source tests no later than 90 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit the source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test of the date and time of the scheduled test.

AQ-D14 The project owner shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be Tested	Required Test Method(s)	Averaging Time	Test Location
SOx emissions	AQMD Laboratory Method 307-91	NA	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A / District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment

The test(s) shall be conducted in accordance with the testing frequency requirements specified in Rule 1146.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when this equipment is operating at 100 percent of maximum load.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD.

[Rule 1146, RULE 1303(a)(1)-BACT, RULE 1303(b)(2)-Offset, RULE 1703(a)(2)-PSD-BACT]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall test according to the original protocol. If changes to the testing methods or testing conditions are proposed then the project owner shall submit a revised protocol for the source tests no later than 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit the source test results no later than 60 days following the source test date to both the District and CPM. The project owner shall notify the District and CPM no later than 10 days prior to the proposed initial source test of the date and time of the scheduled test.

AQ-D15 The project owner shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv.

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9% - %O_2 d)][(Qg * HHV)/10E+06], where:

1. K = 7.267 *10E-08 (lb/scf)/ppm
2. Cco = Average of four consecutive 15 min. average CO concentrations, ppm
3. Fd = 8710 dscf/MMBTU natural gas
4. %O_2 d = Hourly average % by volume O_2 dry, corresponding to Cco
5. Qg = Fuel gas usage during the hour, scf/hr
6. HHV = Gross high heating value of fuel gas, BTU/scf

[RULE 1303(a)(1)-BACT; RULE 1703(a)(2) – PSD-BACT]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit the SCAQMD approved CEMS plan to the CPM within 90 days of SCAQMD approval. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D16 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv.

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD REG XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the project owner shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[RULE 1703(a)(2) – PSD-BACT, RULE 2005, RULE 2012]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit the SCAQMD approved CEMS plan to the CPM within 90 days of SCAQMD approval. The project owner shall make the site available for inspection of records by representatives of the District, ARB, and the Energy Commission.

AQ-D17 The project owner shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

Concentrations shall be corrected to 3 percent oxygen on a dry basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the auxiliary boiler, and in accordance with an approved SCAQMD REG XX CEMS plan application. The project owner shall not install the CEMS prior to receiving initial approval from SCAQMD.

Rule 2012 provisional RATA testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the boiler commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the project owner shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[RULE 1703(a)(2) – PSD-BACT, RULE 2005, RULE 2012]

[Devices subject to this condition: D181 (auxiliary boiler)]

<u>Verification:</u> The project owner shall submit the SCAQMD approved CEMS plan to the CPM within 90 days of SCAQMD approval. The project owner shall make thesite available for inspection of records by representatives of the District, ARB, and the Energy Commission.

Equipment Operation/Construction Requirements

AQ-E1 The project owner shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 13-AFC-01 project.

[CA PRC CEQA]

[Devices subject to this condition: D163, D164, D165, C170, D173, C178, D181, C183, D185, C188, D191, C194, D197, C200, D203, C206, D209, D210]

<u>Verification:</u> The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E2 The project owner shall construct this equipment according to the following requirements:

The Permit to Construct shall expire one year from the issuance date, unless an extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment.

Construction of Phase 1 of the project (defined as the combined-cycle turbines and associated control equipment, the auxiliary boiler and associated control equipment, storage tank D163, and oil water separator D209), shall commence within 18 months from the date of the Permit to Construct, unless an extension is granted by the Permitting Authority (SCAQMD).

Construction of Phase 2 of the project (defined as the simple cycle turbines and associated control equipment, storage tank D164, and oil water separator D210) shall commence within 18 months of May 31, 2020 unless an extension is granted by the Permitting Authority (SCAQMD).

Construction shall not be discontinued for a period of 18 months or more at any time during Phase 1 or Phase 2.

[RULE 205, 40 CFR 52.21 - PSD]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil-water separators)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E3 The project owner shall operate and maintain this equipment according to the following requirements:

Total commissioning hours shall not exceed 996 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 996 hours, commissioning hours without control shall not exceed 216 hours.

Two turbines may be commissioned at the same time.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning is completed.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit all records including the total number of commissioning hours, number of commissioning hours without control, and fuel usage per turbine to demonstrate compliance with this condition as part of the Quarterly Operational Report required in **AQ-SC7**. The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E4 The project owner shall operate and maintain this equipment according to the following requirements:

Total commissioning hours shall not exceed 280 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 280 hours, commissioning hours without control shall not exceed 4 hours.

Four turbines may be commissioned at the same time.

The project owner shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning is completed.

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit all records including the total number of commissioning hours, number of commissioning hours without control, and fuel usage per turbine to demonstrate compliance with this condition as part of the Quarterly Operational Report required in **AQ-SC7**. The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E5 The project owner shall operate and maintain this equipment according to the following requirements

Total commissioning hours shall not exceed 30 hours of fired operation for the auxiliary boiler from the date of initial boiler start-up.

The project owner shall vent this equipment to the SCR control system whenever the auxiliary boiler is in operation after commissioning is completed.

The project owner shall provide the SCAQMD with written notification of the initial startup date. The project owner shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request. The records shall include, but not be limited to, the number of commissioning hours and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, RULE 1703(a)(2)-PSD-BACT, RULE 2005]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall submit all records including the total number of commissioning hours and fuel usage to demonstrate compliance with this condition as part of the Quarterly Operational Report required in **AQ-SC7**. The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E6 The project owner shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The 1000 lbs per gross megawatt-hours CO_2 emission limit (inclusive of degradation) shall only apply if this turbine supplies greater than 1,481,141 MWh-net electrical output to a utility power distribution system on both a 12-operating-month and a 3-year rolling average basis.

Compliance with the 1000 lbs per gross megawatt-hours CO_2 emission limit (inclusive of degradation) shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.

[40 CFR 60 Subpart TTTT]

[Devices subject to this condition: D165, D173]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E7 The project owner shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The 120 lbs/MMBtu CO_2 emission limit shall only apply if this turbine supplies no more than 1,481,141 MWh-net electrical output to a utility power distribution system on either a 12-operating-month or a 3-year rolling average basis.

Compliance with the 120 lbs/MMBtu CO_2 emission limit shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT.

[40 CFR 60 Subpart TTTT]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E8 The project owner shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The 120 lbs/MMBtu CO_2 emission limit for non-base load turbines shall apply.

Compliance with the 120 lbs/MMBtu CO_2 emission limit shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT, including applicable requirements for recordkeeping and reporting.

[40 CFR 60 Subpart TTTT]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E9 The project owner shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

GHG = 61.41 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 610,480 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 937.88 lbs per gross megawatt-hours (inclusive of equipment degradation).

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E10 The project owner shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The project owner shall record the total net power generated in a calendar month in megawatt-hours.

The project owner shall calculate and record greenhouse gas emissions for each calendar month using the following formula:

GHG = 61.41 * FF

Where GHG is the greenhouse gas emissions in tons of CO_2 and FF is the monthly fuel usage in millions standard cubic feet.

The project owner shall calculate and record the CO_2 emissions in pounds per net megawatt-hour based on a 12-month rolling average. The CO_2 emissions from this equipment shall not exceed 120,765 tons per year per turbine on a 12-month rolling average basis. The calendar annual average CO_2 emissions shall not exceed 1,356.03 lbs per gross megawatt-hours (inclusive of equipment degradation).

The project owner shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1714]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E11 The project owner shall comply with the following requirements:

The total electrical output on a gross basis from Combined-Cycle Turbines Nos. CCGT-1 and CCGT-2 (Devices D165 and D173, respectively), common Steam Turbine Generator, and Simple-Cycle Turbines Nos. SCGT-1, SCGT-2, SCGT-3, and SCGT-4 (Device D185, D191, D197, and D203, respectively) shall not exceed 1094.7 MW-gross at 59 degree Fahrenheit.

The gross electrical output shall be measured at the single generator serving each of the combined-cycle turbines, the single generator serving the common steam turbine, and the single generator servicing each of the simple-cycle turbines. The monitoring equipment shall meet ANSI Standard No. C12 or equivalent, and have an accuracy of +/- 0.2 percent. The gross electrical output from the generators shall be recorded at the CEMS DAS over a 15-minute averaging time period.

The project owner shall record and maintain written records of the maximum amount of electricity produced from this equipment and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

[RULE 1303(b)(2)-Offset, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4^{th} quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-E12 The project owner shall vent this equipment, during filling, only to the vessel from which it is being filled.

[RULE 1303(a)(1)-BACT]

[Devices subject to this condition: D163, D164 (ammonia tank)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E13 The project owner shall construct, operate, and main this equipment according to the following requirements:

The equipment shall be equipped with a fixed cover to minimize VOC emissions.

[Devices subject to this condition: D209, D210 (oil water separator)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission.

AQ-E14 Notwithstanding the requirements of Section E conditions, the project owner may commence the construction of Phase II of this project if all the following condition(s) are met:

The BACT/LAER determination for Phase II of this project shall be reviewed and modified (by SCAQMD) as appropriate at the latest reasonable time which occurs no later than 18 months prior to the commencement of construction of Phase II of the project.

[40 CFR 52.21 - PSD]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle), D181 (auxiliary boiler), C170, C178 (combined-cycle control), C188, C194, C200, C206 (simple-cycle control), C183 (auxiliary boiler control), D163, D164 (ammonia tanks), D209, D210 (oil water separator)]

Verification: The project owner shall submit to the CPM documentation that the BACT/LAER determination was reviewed by the SCAQMD prior to the commencement of construction of Phase II. The documentation shall include any modifications to the BACT/LAER determination made by the SCAQMD. Any modification to the BACT/LAER determination shall be submitted to the Energy Commission compliance project manager as an amendment request.

Applicable Rules

AQ-H1 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	1146

[RULE 1146]

[Devices subject to this condition: D181 (auxiliary boiler)]

Verification: The project owner shall make the site available for inspection by representatives of the District, ARB, U.S. EPA and the Energy Commission..

Administrative

AQ-I1 This equipment shall not be operated unless the facility holds 108,377 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle)]

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-I2 This equipment shall not be operated unless the facility holds 68,575 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005]

[Devices subject to this condition: D185, D191, D197, D203 (simple-cycle)]

<u>Verification:</u> The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

AQ-I3 This equipment shall not be operated unless the facility holds 1,351 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[RULE 2005]

[Devices subject to this condition: D181 (auxiliary boiler)]

<u>Verification:</u> The project owner shall submit to the CPM for approval all emissions and emission calculations to demonstrate compliance with this condition as part of the 4th quarter Quarterly Operational Report required in **AQ-SC7**.

Record Keeping Reporting

AQ-K1 The project owner shall provide to the District a source test report in accordance with the following requirements:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.2 (**AQ-D10**), D29.3 (**AQ-D11**), and D29.4 (**AQ-D12**), are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), lbs/MM cubic feet, and lbs/MMBtu. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[RULE 1303(a)(1)-BACT, RULE 1303(b)(2)-Offset, RULE 1703(a)(2) – PSD-BACT, RULE 2005]

[Devices subject to this condition: D165, D173 (combined-cycle), D185, D191, D197, D203 (simple-cycle)]

Verification: The project owner shall submit the source test results no later than 90 days following the source test date to both the District and CPM.

AQ-K2 The project owner shall provide to the District a source test report in accordance with the following requirements:

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.5 (**AQ-D13**), D29.6 (**AQ-D14**), and D29.4 (**AQ-D12**), are conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 3 percent oxygen (dry basis), mass rate (lbs/hr), lbs/MM cubic feet, and lbs/MMBtu. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All moisture concentration shall be expressed in terms of percent corrected to 3 percent oxygen.

Source test results shall also include, for each firing rate, the following operating data: (1) the exhaust flow rates, in actual cubic feet per minute (acfm), (2) the firing rates in Btu/hour, (3) the exhaust temperature, in degrees Fahrenheit, (4) the oxygen content of the exhaust gases, in percent, and (5) the fuel flow rate.

[RULE 1146, RULE 1303(a)(1)-BACT, RULE 1303(b)(2)-Offset, RULE 1703(a)(2) – PSD-BACT, RULE 2005]

[Devices subject to this condition: D181]]

Verification: The project owner shall submit the source test results no later than 90 days following the source test date to both the District and CPM.

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ACRONYMS

AAQS	Ambient Air Quality Standard
ACC	Air Cooled Condenser
AERMOD	AMS/EPA Regulatory Model
AEC	Alamitos Energy Center
AES	AES Alamitos Energy-LLC
AES-SD	AES Southland, Development, LLC
AFC	Application for Certification
AGS	Alamitos Generating Station
APCO	Air Pollution Control Officer
AIP	Achieved in Practice
AQCMM	Air Quality Construction Mitigation Manager
AQCMP	Air Quality Construction Mitigation Plan
AQMD	Air Quality Management District
AQMP	Air Quality Management Plan
ARB	California Air Resources Board
ASOS	Automated Surface Observing Systems
ATC	Authority to Construct
BACT	Best Available Control Technology
bhp	brake horsepower
Btu	British Thermal Unit
CAAQS	California Ambient Air Quality Standards
CA ISO	California Independent System Operator
CAM	Compliance Assurance Monitoring
CCGT	Combined-Cycle Gas Turbine
CCR	California Code of Regulations
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	(CEC) Compliance Project Manager
CTG	Combustion Turbine Generator
DPM	Diesel Particulate Matter
EIR	Environmental Impact Report
EPA	Environmental Protection Agency

ERC	Emission Reduction Credit
ESEC	El Segundo Energy Center
FDOC	Final Determination of Compliance
FSA	Final Staff Assessment
GE	General Electric
GHG	Greenhouse Gas
gr/dscf	Grains per Dry Standard Cubic Foot
H_2S	Hydrogen Sulfide
HAPs	Hazardous Air Pollutants
hp	Horsepower
hr	Hour
HRSG	Heat recovery Steam Generator
HSC	Health and Safety Code
ICE	Internal Combustion Engine
IP	Implementation Plan
kV	Kilovolt
lb/mmscf	Pounds per Million Standard Cubic Feet
LAER	Lowest Achievable Emission Rate
Lb(s)	Pounds
LLC	Limited Liability Company
LORS	Laws, Ordinances, Regulations and Standards
MCR	Monthly Compliance Report
m^3	Cubic Meter
$\mu g/m^3$	Microgram per Cubic Meter
mg/m^3	Milligrams per Cubic Meter
MMBtu	Million British Thermal Units
m/s	Meters per Second
$MTCO_2$	Metric Ton of Carbon Dioxide
MW	Megawatts (1,000,000 Watts)
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Protection Act
NESHAP	National Emission Standard for Hazardous Air Pollutants
ng/J	Nanograms per Joule
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard

NSR	New Source Review
O_2	Oxygen
O_3	Ozone
OLM	Ozone Limiting Method
OTC	Once-Through-Cooling
Pb	Lead
PDOC	Preliminary Determination of Compliance
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
Ppb	Parts Per Billion
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment (this document)
PSD	Prevention of Significant Deterioration
PTA	Petition to Amend
PTC	Permit to Construct
PTE	Potential to Emit
PTO	Permit to Operate
RECLAIM	Regional Clean Air Incentives Market
RTC	RECLAIM Trade Credit
RTO	Regenerative Thermal Oxidizer
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet
SCE	Southern California Edison
SCGT	Simple Cycle Gas Turbine
SIP	State Implementation Plan
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_4	Sulfate
SOx	Oxides of Sulfur
SCAB	South Coast Air Basin
SCAG	Southern California Association of Governments
STG	Steam Turbine Generator
SWPPP	Storm Water Pollution Prevention Plan

SWRCB	California State Water Resources Control Board
T-BACT	Toxic Best Available Control Technology
TCM	Transportation Control Measures
tpy	tons per year
U.S. EPA	United States Environmental Protection Agency
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compounds

AIR QUALITY APPENDIX AIR-1

Greenhouse Gas Emissions

Testimony of Nancy Fletcher and David Vidaver

SUMMARY

The Alamitos Energy Center (AEC) project is a proposed addition to the state's electricity system. It would be an efficient, new, dispatchable natural gas-fired facility with both combined-cycle and simple-cycle units that would provide fast start capabilities but would produce greenhouse gas (GHG) emissions while generating electricity for California consumers.

AEC would improve the efficiency of existing system resources and contribute to a reduction of system wide GHG emissions from the Western U.S. electricity sector in several ways:

- When dispatched,[2] AEC would displace less efficient (and thus higher GHG-emitting) generation. Because the project's GHG emissions per megawatt-hour (MWh) would be lower than those power plants that the project would displace, the addition of AEC would contribute to a reduction of Western Electricity Coordinating Council system GHG[3] emissions overall and the GHG emission rate average.
- AEC would provide fast start and dispatch flexibility capabilities necessary to integrate expected and desired additional amounts of variable renewable generation (also known as "intermittent" energy resources) to meet the state's renewable portfolio standard (RPS) and GHG emission reduction targets.
- AEC would replace capacity and generation mostly provided by aging, high GHG emitting power plants, including the existing Alamitos Generating Station (AGS) that will likely be retired in order to comply with the State Water Resource Control Board's (SWRCB) policy on the use of once through cooling (OTC).
- AEC would replace less efficient generation in the South Coast local reliability area required to meet local reliability needs, reducing the GHG emissions associated with providing local reliability services and facilitating the retirement of aging, high GHG-emitting resources in the area.

[2] The entity responsible for balancing a region's electrical load and generation will "dispatch" or call on the operation of generation facilities. The "dispatch order" is generally dictated by the facility's electricity production cost, efficiency, location or contractual obligations.
[3] Fuel-use closely correlates to the efficiency of and carbon dioxide (CO_2) emissions from natural gas-fired power plants. And since CO_2 emissions from fuel combustion dominate greenhouse gas (GHG) emissions from power plants, the terms CO_2 and GHG are used interchangeably in this section.

INTRODUCTION

Gases that trap heat in the atmosphere are called greenhouse gases (GHGs). GHG emissions are not criteria pollutants with direct impacts; they are discussed in the context of cumulative impacts. In December 2009, the U.S. Environmental Protection Agency (U.S. EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the current and future generations (the “endangerment finding”). This finding became effective on January 14, 2010.

The generation of electricity using any fossil fuel, including natural gas, can produce GHGs along with the criteria air pollutants that have been traditionally regulated under the federal and state Clean Air Acts (CAA). For fossil fuel-fired power plants, GHG emissions include primarily CO_2, with much smaller amounts of nitrous oxide (N_2O, not NO or NO_2 which are commonly known as NOx or oxides of nitrogen), and methane (CH_4 – often from unburned natural gas). Also included are sulfur hexafluoride (SF_6) from high voltage equipment and hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs) from refrigeration/chiller equipment. GHG emissions from the electricity sector are dominated by CO_2 emissions from carbon-based fuels. Other sources of GHG emissions are small and more easily controlled, reused or recycled. These sources of GHG are included in the analysis because some of the compounds have very high relative global warming potentials[4].

The State has demonstrated a clear willingness to address global climate change though research, adaptation,[5] and GHG inventory reductions. In that context, staff evaluates GHG emissions from the proposed project, presents information on GHG emissions related to electricity generation, and describes the applicable GHG standards and requirements.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS) COMPLIANCE

The following federal, state, and local laws and policies in **Greenhouse Gas Table 1** pertain to the control and mitigation of greenhouse gas emissions. Staff’s analysis examines the project’s compliance with each of these requirements. Additional analysis of AEC’s compliance with these LORS is included in the **Compliance with LORS** section.

[4] Global warming potential is a relative measure, compared to carbon dioxide, of a compound’s residence time in the atmosphere and ability to warm the planet. Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2e) for ease of comparison.
[5] While working to understand and reverse global climate change, it is prudent to also adapt to potential changes in the state’s climate (for example, changing rainfall patterns).

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria See discussions below.
[2] 40 Code of Federal Regulations (CFR) Parts 51 and 52	A new stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source subject to PSD requirements. As of June 23, 2014 the US Supreme Court has invalidated this requirement as a sole PSD permitting trigger. However, for permits issued on or after July 1, 2011 PSD applies to GHGs if the source is otherwise subject to PSD (for another regulated NSR pollutant) and the source has a GHG potential to emit (PTE) equal to or greater than 75,000 TPY CO_2e. The proposed AEC is subject to GHG PSD analysis.
40 Code of Federal Regulations (CFR) Parts 60, 70, 71 and 98	On October 23, 2015, U.S. EPA published new source performance standards (NSPS) for greenhouse gas emissions for new, modified, and reconstructed fossil fuel-fired electric utility generating units. AEC turbines would be subject to these requirements.
40 Code of Federal Regulations (CFR) Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year. This requirement is triggered by this facility.
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards to reduce GHG emission to 1990 levels by 2020. Electricity production facilities are included. A cap-and-trade program became active in January 2012, with enforcement beginning in January 2013. Cap-and-trade is expected to achieve approximately 20 percent of the GHG reductions expected under AB 32 by 2020.
California Code of Regulations, Title 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, Section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh).
Local	
Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases, Gas Turbines	This rule establishes preconstruction review requirements for greenhouse gases (GHG). This rule is consistent with federal PSD rule as defined in 40 CFR Part 52.21. This rule requires the owner or operator of a new major source or a major modification to obtain a PSD permit prior to commencing construction.

GHG ANALYSIS

California is actively pursuing policies to reduce GHG emissions that include adding low-GHG emitting renewable electricity generation resources to the system. Since the impact of the GHG emissions from a power plant's operation has global rather than local effects, those impacts are assessed not only by analysis of the plant's emissions, but also in the context of operation of the entire electricity system of which the plant would be an integrated part. Furthermore, the impact of the GHG emissions from a power plant's operation should be analyzed in the context of applicable GHG laws and policies, especially Assembly Bill (AB) 32, California's Global Warming Solutions Act of 2006.

GLOBAL CLIMATE CHANGE AND CALIFORNIA

There is general scientific consensus that climate change is occurring and that human activity contributes in some measure (perhaps substantially) to that change. Man-made emissions of GHGs, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. Indeed, the California Legislature found that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California" (Cal. Health & Safety Code, sec. 38500, division 25.5, part 1).

GHGs differ from criteria pollutants in that GHG emissions from a specific project do not cause direct adverse localized human health effects. Rather, the direct environmental effect of GHG emissions is the cumulative effect of an overall increase in global temperatures, which in turn has numerous indirect effects on the environment and humans. The impacts of climate change include potential physical, economic and social effects. These effects could include inundation of settled areas near the coast from rises in sea level associated with melting of land-based glacial ice sheets, exposure to more frequent and powerful climate events, and changes in suitability of certain areas for agriculture, reduction in Arctic sea ice, thawing permafrost, later freezing and earlier break-up of ice on rivers and lakes, a lengthened growing season, shifts in plant and animal ranges, earlier flowering of trees, and a substantial reduction in winter snowpack (IPCC 2007b). For example, current estimates include a 70 to 90 percent reduction in snow pack in the Sierra Nevada mountain range. Current data suggests that in the next 25 years, in every season of the year, California could experience unprecedented heat, longer and more extreme heat waves, greater intensity and frequency of heat waves, and longer dry periods.

Each of the first six months of 2016 set a record as the warmest respective month globally in the modern temperature record, which dates to 1880, according to scientists at NASA's Goddard Institute for Space Studies (GISS) in New York. The six-month period from January to June was also the planet's warmest half-year on record, with an average temperature 1.3 degrees Celsius (2.4 degrees Fahrenheit) warmer than the late nineteenth century (NASA/Goddard 2016). October 2016 was the second warmest October in 136 years of modern record-keeping, according to a monthly analysis of global temperatures by scientists at NASA's Goddard Institute for Space Studies (GISS) in New York[6]. According to “The Future Is Now: An Update on Climate Change Science Impacts and Response Options for California,” an Energy Commission document, the American West is heating up faster than other regions of the United States (CEC 2009c). The California Climate Change Center (CCCC) reports that, by the end of this century, average global surface temperatures could rise by 4.7°F to 10.5°F due to increased GHG emissions.

Recent data collected at Mauna Loa, Hawaii indicate that the atmospheric CO_2 concentration now exceeds 400 ppm all year, and recent research suggests that values will remain above this level (Betts et al 2016). According to the latest information available from the Intergovernmental Panel on Climate Change in their document “Climate Change 2014” (IPCC 2016), atmospheric CO_2 concentrations of 430 to 480 ppm would be expected to cause an approximate 2.7 degree Fahrenheit (F) temperature increase and CO_2 concentrations ranging from 580 ppm to 650 ppm are expected to cause an approximate 3.6 F temperature increase.

In April 2007, the U.S. Supreme Court held that GHG emissions are pollutants within the meaning of the Clean Air Act (CAA). In reaching its decision, the Court also acknowledged that climate change results, in part, from anthropogenic causes (Massachusetts et al. v. Environmental Protection Agency 549 U.S. 497, 2007). The Supreme Court’s ruling paved the way for the regulation of GHG emissions by U.S. Environmental Protection Agency (U.S. EPA) under the CAA.

In response to this Supreme Court decision, on December 7, 2009 the U.S. EPA Administrator signed two distinct findings regarding GHGs under Section 202(a) of the CAA:

- Endangerment Finding: That the current and projected concentrations of the GHGs in the atmosphere threaten the public health and welfare of current and future generations; and
- Cause or Contribute Finding: That the combined emissions of GHGs from new motor vehicles and new motor vehicle engines contribute to the GHG pollution, which threatens public health and welfare.

As of June 23, 2014, the U.S. Supreme Court has validated that GHG emissions should continue to be regulated, but only for those facilities that are already regulated under Prevention of Significant Deterioration (PSD) for New Source Review (NSR) pollutants.

[6] http://data.giss.nasa.gov/gistemp/news/20161115/

On October 23, 2015, the U.S. EPA published in the Federal Register a New Source Performance Standard (NSPS) for GHG emissions for new electric power plants with an immediate effective date. It sets standards to limit emissions of CO_2 from new, modified and reconstructed power plants. The New Source Performance Standards Subpart TTTT-Standards of Performance for Greenhouse Gas Emissions for Electrical Generating Units (Title 40, Code of Federal Regulations, Part 60.5508) are set under the authority of the Clean Air Act section 111(b) and are applicable to new fossil fuel-fired power plants commencing construction after January 8, 2014.

According to Subpart TTTT, base load rating is defined as maximum amount of heat input that an electric generating unit (EGU) can combust on a steady state basis at standard conditions (ISO conditions). For stationary combustion turbines, base load rating includes the heat input from duct burners. Each EGU is subject to the standard if it burns natural gas on a 12-month rolling basis more than 90% of the time and if the EGU supplies more than the design efficiency times the potential electric output as net-electric sales on a 3 year rolling average basis. Affected EGUs supplying equal to or less than the design efficiency times the potential electric output as net electric sales on a 3 year rolling average basis are considered non-base load units and are subject to a heat input limit of 120 lbs CO_2/MMBtu. Each affected 'base load' EGU is subject to the gross energy output standard of 1,000 lbs of CO_2/MWh unless the Administrator approves the EGU being subject to a net energy output standard of 1,030 lbs CO_2/MWh. AES would comply with these requirements. See the **Air Quality** section for further discussion.

AEC combined-cycle turbines would be expected to supply more than the design efficiency times the potential electric output as net-electric sales on a 3 year rolling average basis and would therefore be considered base load units. The combined-cycle turbines would be subject to a gross energy output standard of 1,000 lbs of CO_2 per megawatt hour (MWh) or a net energy output standard of 1,030 lbs CO_2/MWH. The project owner has proposed demonstrating compliance on a gross energy output basis. Should the combined cycle operate as non-base load unit, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. The simple cycle units would also be subject to the 120 lb CO_2 per MMBtu limit and would be expected to comply by the use of natural gas.

SB 1368, enacted in 2006, and regulations adopted by the Energy Commission and the CPUC pursuant to that bill, prohibits California utilities from entering into long-term commitments with any base load facilities that exceed the Emission Performance Standard (EPS) of 0.5 metric tonnes CO_2 per megawatt-hour (1,100 pounds CO_2/MWh). Specifically, the SB 1368 EPS applies to new California utility-owned 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, where the power plants are “designed or intended” to operate as base load generation. If a project, in state or out of state, plans to sell electricity or capacity to California utilities, those utilities will have to demonstrate that the project meets the EPS. *Base load* units are defined as units that are expected to operate at a capacity factor 60 percent or higher. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. This determination is based on capacity factors, heat rates, and corresponding emissions rates that reflect the *expected* operations of the power plant and not on full load heat rates [Chapter 11, Article 1 §2903(a)].

AEC would be required to participate in California’s GHG cap-and-trade program. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB 32, which is being implemented by ARB. As currently implemented, market participants such as AEC are required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB 32 program. As new participants enter the market and as the market cap is ratcheted down over time, GHG emission allowance and offset prices will increase, encouraging innovation by market participants to reduce their GHG emissions. Thus, AEC, as a GHG cap-and-trade participant, would be consistent with California’s AB 32 Program.

On May 22, 2014, the Air Resources Board (ARB) released its first update to their AB32 Scoping Plan. On April 29, 2015, Governor Brown issued Executive Order B-30-15, directing state agencies to implement measures to reduce GHG emissions 40 percent below their 1990 levels by 2030 and to achieve the previously-stated goal of an 80 percent GHG reduction by 2050. In response, ARB is again updating the AB32 Scoping Plan. If this project is built after 2020, the GHG regulatory landscape could be different than today.

On June 17, 2016, ARB released a concept paper addressing four options for updating the Scoping Plan that focus on extending AB32 requirements beyond the year 2020. There are four alternatives listed in the concept paper, described as Concepts 1 to 4. These are summarized as follows:

1. Extending cap-and-trade and other complementary programs,

2. Expand complementary programs without extending cap-and-trade,

3. Aggressively expand transportation-related programs and other complementary programs without extending cap and trade, and

4. Replace cap-and-trade with a carbon tax and expanded complementary programs.

Staff's GHG analysis assumes the cap-and-trade provisions of AB32 would continue as envisioned in Concept 1. If a carbon tax replaces cap-and-trade as envisioned in Concept 4, the effect on PRP is expected to be approximately the same, depending on how the carbon tax is levied. However, if the cap-and-trade approach is abandoned as in Concepts 2 and 3, the only programmatic approach currently in place would apply to reducing GHG emissions from power plants would be the federal New Source Performance Standard requirements being developed by the U.S. EPA. As currently proposed, AEC would comply with these federal GHG requirements.

On September 8, 2016, Senate Bill 32,codified as Section 38566 of the Health and Safety Code, was enacted. It extends California's commitment to reduce GHG emissions by requiring the state to reduce statewide emissions to below 1990 levels by 2030.

ELECTRICITY SYSTEM GREENHOUSE GAS EMISSIONS

While electricity use can be as simple as turning on a switch to operate a light or fan, the system to deliver the adequate and reliable electricity supply is complex and variable. It operates as an integrated whole to reliably and effectively meet demand, such that the dispatch of a new source of generation unavoidably curtails or displaces one or more less efficient or less competitive existing sources. Within the system, generation resources provide electricity, or energy, generating capacity, and ancillary services to stabilize the system and facilitate electricity delivery, or movement, over the grid. *Capacity* is the instantaneous output of a resource, in megawatts. *Energy* is the capacity output over a unit of time, for example an hour or year, generally reported as megawatt-hours or gigawatt-hours (GWh). Ancillary services[7] include regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. Individual generation resources can be built and operated to provide only one specific service. Alternatively, a resource may be able to provide one or all of these services, depending on its design and constantly changing system needs and operations.

GHG EMISSIONS FROM THE PROPOSED FACILITY

Project Construction

Construction of industrial facilities such as power plants requires coordination of numerous equipment and personnel. The concentrated on-site activities result in temporary, unavoidable increases in vehicle and equipment emissions that include greenhouse gases. Construction of the AEC project would include the Alamitos Generating Station Unit 7 demolition, combined-cycle construction, and simple-cycle construction occurring over approximately 56 months. The project owner provided an annual GHG emission estimate for the construction phase. The GHG emissions estimate is presented below in **Greenhouse Gas Table 2**. The term CO_2e represents the total GHG emissions after weighting by the appropriate global warming potential.

[7] See CEC 2009b, page 95.

Greenhouse Gas Table 2
Estimated Maximum Annual Construction Greenhouse Gas Emissions

AEC	GHG Construction Emissions, Metric Tons per Year[a]			
	CO_2	CH_4	N_2O	CO_2e
Weighted Construction Total[b]	6,591	3.25	16.99	6,611

Source: AEC 2015 Table 5.1A30 CH2 2016s, CH2 2016aa, CH2 2016bb, staff analysis
Notes: [a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Global Warming Potential weighting factors: CH_4 = 25, N_20 =298

Project Operations

The primary sources of GHG during operation of the AEC would be the natural gas fired combustion turbines and the auxiliary boiler. The employee and delivery traffic GHG emissions from off-site activities are negligible in comparison with the gas turbine GHG emissions.

Greenhouse Gas Table 3 shows estimated annual GHG emissions of CO_2 and CO_2e for the AEC combined-cycle portion only (power block 1). The <u>parameters reflect predicted actual operation to conservatively demonstrate the plant would satisfy the requirements based on how it intends to operate.</u>

Greenhouse Gas Table 3
AEC Combined Cycle (Power Block 1)
Estimated Potential Annual Greenhouse Gas (GHG) Emissions

AEC	Operational GHG Emissions ($MTCO_2e/yr$)[a]
Carbon Dioxide (CO_2)	1,100,963
Methane (CH_4)	206
Nitrous Oxide (N_2O)	9.24
Sulfur Hexafluoride (SF_6) Leakage	15.8
Total Project GHG Emissions ($MTCO_2e/yr$)[b]	**1,101,194**
Estimated Annual Energy Output (MWh/yr)[c]	2,509,309
Estimated Annualized GHG Performance ($MTCO_2/MWh$)	**0.44**

Source: AEC 2015 Table 5.1A30 CH2 2016s, CH2 2016aa, CH2 2016bb SCAQMD 2016e, staff analysis
Notes: [a] One metric tonne (MT) equals 1.1 short tons or 2,204.6 pounds or 1,000 kilograms.
[b] Global Warming Potential weighting factors: CH_4 = 25, N_20 =298, SF6 = 22,800
[c] Annualized basis uses the project owner's assumed maximum permitted operating basis.

The project owner expects the plant capacity factor of the AEC (both the combined-cycle and simple-cycle turbines) each to be below 60 percent. Therefore, the AEC would not be subject to SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 $MTCO_2$/MWh. The combined cycle portion of AEC (block 1) is the only portion of the proposed facility whose actual operation could potentially approach a 60 percent capacity factor. It would comply with this requirement should it operate at a 60 percent capacity factor.

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

Staff assesses the cumulative effects of GHG emissions caused by both construction and operation. As the name implies, construction impacts result from the emissions occurring during the construction of the project. The operation impacts result from the emissions of the proposed project during operation.

METHOD AND THRESHOLDS FOR DETERMINING SIGNIFICANCE

The CEQA guidelines provide three factors for lead agencies to consider when assessing the significance of impacts for the analysis of GHG emissions impacts (CEQA Guidelines, tit. 14, §15064.4).

- *The extent to which the project may increase or reduce greenhouse gas emissions as compared to the existing environmental setting;*
- *Whether the project emissions exceed a threshold of significance that the lead agency determines applies to the project; and*
- *The extent to which the project complies with regulations or requirements adopted to implement a statewide, regional, or local plan for the reduction or mitigation of greenhouse gas emissions. Such requirements must be adopted by the relevant public agency through a public review process and must reduce or mitigate the project's incremental contribution of greenhouse gas emissions. If there is substantial evidence that the possible effects of a particular project are still cumulatively considerable notwithstanding compliance with the adopted regulations or requirements, an EIR must be prepared for the project.*

Staff evaluates the emissions of the project in the context of the electricity sector as a whole and the AB 32 Scoping Plan implementation efforts for the sector, including the cap and trade regulation that constitutes the state's primary mechanism for reducing GHG emissions from the electricity sector. The Energy Commission's assessment approach does not include a specific numeric threshold of significance for GHG emissions; rather the assessment is completed in the context of how the project will affect the electricity sector's emissions based on its proposed role and its compliance with applicable regulations and policies.

Included in this sector-wide GHG emission analysis method is the determination of whether a project is consistent with the Avenal precedent decision, which requires a finding as a conclusion of law that any new natural gas-fired power plant certified by the Energy Commission "must:

- *not increase the overall system heat rate for natural gas plants;*
- *not interfere with generation from existing renewables or with the integration of new renewable generation; and*

- *taking into account the two preceding factors, reduce system-wide GHG emissions."*[8]

CONSTRUCTION EMISSIONS

Staff believes that the small GHG emission increases from mitigated construction activities would not be significant for several reasons. First, the intermittent emissions during the construction phase are not ongoing during the life of the project. Additionally, control measures that staff recommends to address criteria pollutant emissions, such as limiting idling times and requiring, as appropriate, equipment that meets the latest criteria pollutant emissions standards, would further minimize greenhouse gas emissions to the extent feasible. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

DIRECT/INDIRECT OPERATION IMPACTS AND MITIGATION

Operational impacts of the proposed project are described in detail in a later section titled "**The Impact of the AEC on GHG Emissions from the State's Electricity Sector**" since the evaluation of these effects must be done by considering the project's role(s) in the integrated electricity system. In summary, these effects include reducing the operation and greenhouse gas emissions from the older, existing power plants; potentially displacing local electricity generation; the penetration of renewable resources; and accelerating generation retirements and replacements, including facilities currently using once-through cooling. Additionally, GHG emissions impacts arising from operation are mitigated through compliance with the State's cap and trade regulation, which is designed to reduce electricity sector GHG emissions over time in order to meet AB 32 statewide GHG emissions reduction goals.

CUMULATIVE IMPACTS

Cumulative impacts are defined as "two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts" (CEQA Guidelines § 15355). "A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts" (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

This entire assessment is a cumulative impact assessment. The project alone would not be sufficient to change global climate, but would emit greenhouse gases and therefore has been analyzed as a potential cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies.

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[8] Final Commission Decision, Avenal Energy Application for Certification (08-AFC-1) December 2009, p. 114.

COMPLIANCE WITH LORS

FEDERAL

To evaluate compliance with federal New Source Performance Standards (NSPS) requirements for GHGs, the SCAQMD FDOC calculated the gross energy output for the combined-cycle and simple-cycle gas turbines. A thermal efficiency of 937.88 lbs CO_2 per MWh (gross), assuming 8 percent performance degradation, was calculated for the proposed combined-cycle turbines. For the combined-cycle turbines, this is less than the allowable 1,000 lbs CO_2/MWh (gross).

A thermal efficiency of 1,356.03 lbs CO_2 per MWh (gross), assuming 8 percent performance degradation, was calculated for the proposed simple-cycle turbines. However, the inability of the simple-cycle turbines to meet the 1,000 lbs CO_2/MWh (gross) limit is expected for these non-base load units and this limit does not apply to them because they are expected to have capacity factors less than their lower heating value efficiency. The applicable limit for them is 120 lb CO_2 per million Btus of heat input. Each GE LMS-100PB turbine is estimated to emit 117 lb CO_2 per MMBtu, which rounds to 120 lb CO_2 per MMBtu at two digits of precision. Conditions of Certification **AQ-E6**, **AQ-E7, AQ-E8 and AQ-E10** would ensure compliance with these NSPS requirements.

STATE

The AEC would be required to participate in California's GHG cap-and-trade program, which became active in January 2012, with enforcement beginning in January 2013. This cap-and-trade program is part of a broad effort by the state of California to reduce GHG emissions as required by AB 32, which is being implemented by ARB. As currently implemented, market participants such as the AEC are required to report their GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing allowances from the capped market and offsets from outside the AB 32 program. The AEC, as a GHG cap-and-trade participant, would be consistent with California's landmark AB 32 Program, which is a statewide program coordinated with a region wide Western Climate Initiative program to reduce California's GHG emissions to 1990 levels by 2020. ARB staff continues to develop and implement regulations to refine key elements of the GHG reduction measures to improve their linkage with other GHG reduction programs.

The project owner has proposed that the AEC would have less than a 60 percent annual full load capacity factor; therefore, AEC would not be subject to the requirements of SB 1368 and the current Emission Performance Standard. The project's combined cycle GHG emission performance has been demonstrated to be below the SB 1368 EPS limit of 1,100 $lb/_{net}$ MWh (see **Greenhouse Gas Table 3**), and with the proposed federal New Source Performance Standard (NSPS) of 1,000 $lb/_{gross}$ MWh for new combustion. The project's simple cycle GHG performance would not be subject to SB 1368 ESP limit.

LOCAL

SCAQMD Rule 1714 establishes preconstruction review requirements for GHGs and the AEC is evaluated for these requirements in the PDOC. The AEC would be a major PSD source. The SCAQMD performed a PSD BACT analysis for GHGs and concluded thermal efficiency is the only technically and economically feasible alternative for CO_2/GHG emissions control for the AEC. The current design proposed for the AEC meets the BACT requirement for GHG emission reductions.

RESPONSE TO PSA COMMENTS

PROJECT OWNER COMMENTS

Alamitos Energy Center (13-AFC-01) Preliminary Staff Assessment Initial Comments, Dated July 27, 2016 (CH 2016AA)

Comment 35:

Page 4.1-162, Greenhouse Gas Table 3 – Based on information presented on pages 109 and 188 of the PDOC, Greenhouse Gas Table 3 should be revised as shown below.

AEC	Operational GHG Emissions ($MTCO_2e$/yr)
Carbon Dioxide (CO_2)	1,109,964
Methane (CH_4)	523
Nitrous Oxide (N_2O)	623
Sulfur Hexafluoride (SF_6) Leakage	15.8
Total Project GHG Emissions ($MTCO_2e$/yr)	1,111,126
Estimated Annual Energy Output (MWh/yr)	3,215,293
Estimated Annualized GHG Performance ($MTCO_2$/MWh)	0.35

Response to Comment 35:

The information presented on pages 109 and 188 of the PDOC is based on potential and maximum operating parameters. Staff's analysis in the Greenhouse Gas Appendix includes parameters reflecting predicted actual operation to conservatively demonstrate the plant would satisfy the requirements based on how it intends to operate. CH2M confirmed the numerical values used for GHG is acceptable given the intent to present a conservative estimate of performance. Staff will add additional text in the FSA GHG section to clarify this conservative approach.

CONCLUSIONS AND RECOMMENDATIONS

The AEC would lead to a net reduction in GHG emissions across the electricity system that provides energy and capacity to California. Thus, staff believes that the AEC would result in a cumulative overall reduction in GHG emissions from the state's power plants, would not worsen current conditions, and would thus not result in impacts that are cumulatively significant. In addition, it would provide flexible, dispatchable and fast-ramping power in relatively small increments of capacity, which should improve the electric system reliability in a high-renewables, low-GHG system.

The AEC would be subject to mandatory reporting of GHG emissions per federal government and California Air Resources Board (CARB) greenhouse gas regulations. These reports enable these agencies to gather information needed to regulate the AEC in trading markets, such as those that are required by regulations implementing the California Global Warming Solutions Act of 2006 (AB 32). In addition, the AEC may be subject to additional reporting requirements and GHG reduction and trading requirements as these regulations continue to evolve.

GHG emissions increases from construction activities would be mitigated. Construction emissions would be temporary and intermittent, and not continue during the life of the project. The control measures or best practices that staff recommends, such as limiting idling times and requiring, as appropriate, equipment that meets the latest emissions standards, would further minimize greenhouse gas emissions. Staff believes that the use of newer equipment would reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that would likely be part of the ARB regulations to reduce GHG from construction vehicles and equipment.

The AEC would not be considered a base load facility subject to the Greenhouse Gases Emission Performance Standard (Title 20, California Code of Regulations, section 2900 et seq.). The proposed AEC combined-cycle gas turbine block (CCGT) would meet the standard of 0.5 metric tonnes CO_2 per megawatt-hour ($MTCO_2$/MWh) with a rating of 0.44 $MTCO_2$/MWh. See **Greenhouse Gas Table 3**.

The GE 7FA.05 combined-cycle turbines are also expected to comply with the federal Standards of Performance for Greenhouse Gas Emissions (or Clean Air Act section 111[b]) of 1,000 pounds of carbon dioxide per gross megawatt hour (lb CO_2/MWh, gross) or (1,030 lb CO_2/ MWh, net) for base load natural gas fueled turbines. The GE LMS-100PB simple-cycle turbines are expected to comply with the limit of 120 lb CO_2 per million Btus (MMBtu) of natural gas heat input for non-base load natural gas-fueled turbines. Should the combined-cycle turbines operate as non-base load units, compliance with the 120 lb CO_2 per MMBtu limit would be expected by the use of natural gas. Conditions of Certification **AQ-E7** and **AQ-E8** would ensure compliance with the new standards.

Staff has reached the following conclusions about the AEC based on CEQA guidelines:

- The AEC would have less than significant GHG emissions impacts because:
    - The combined-cycle portion of the AEC would have lower heat rate and lower GHG emissions than the units utilizing OTC that currently provide a share of the local reliability needs for the local capacity area (LCA). It would also be dispatched in lieu of less efficient, higher-emitting combined cycles when providing local reliability services.
    - The proposed simple-cycle turbines of the AEC would have lower heat rates and lower GHG emissions than those of the existing peaking facilities in the LCA.
    - The AEC would facilitate the integration of renewable energy resources that would lower the state-wide GHG emissions from the electricity sector.

- The AEC would have less than significant impacts by complying with applicable regulations and plans related to the reduction of GHG emissions as follows:
    - o The AEC would be subject to compliance with the AB 32 Cap and Trade regulation that implements the state's regulatory plan for reducing GHG emissions from the electricity sector;
    - o The construction emissions mitigation measures that staff recommends to address criteria pollutant emissions would further minimize GHG emissions. The use of newer equipment will increase efficiency and reduce GHG emissions and be compatible with low-carbon fuel (e.g., bio-diesel and ethanol) mandates that will likely be part of future ARB regulations to reduce GHG from construction vehicles and equipment.

The AEC would be consistent with all three main conditions in the Energy Commission's precedent decision regarding GHG emissions established by the Avenal Energy Project's Final Energy Commission Decision (not increase the overall system heat rate for natural gas plants, not interfere with generation from existing or new renewable facilities, and ensure a reduction of system-wide GHG emissions).

PROPOSED CONDITIONS OF CERTIFICATION

Conditions of Certification **AQ-E6**, **AQ-E7**, **AQ-E8**, **AQ-E9**, and **AQ-E10** in the Air Quality section relate to the greenhouse gas emissions from project operation and are proposed here by reference. The facility owner would participate in California's GHG cap-and-trade program, and is required to report GHG emissions and to obtain GHG emissions allowances (and offsets) for those reported emissions, by purchasing allowances from the capped market and offsets from outside the AB 32 program. Similarly, the AEC would be subject to federal mandatory reporting of GHG emissions. The facility owner may have to provide additional reports and GHG reductions, depending on the future regulations formulated by the U.S. EPA or the ARB.

CALIFORNIA ELECTRICITY AND GREENHOUSE GASES – DAVID VIDAVER

California's commitments to dramatically reduce greenhouse gas (GHG) emissions over the next four decades include moving to a high-renewable/low GHG electricity system. However, natural gas-fired power plants--and the GHG emissions associated with their output--will still be integral to the reliable operation of the electricity system at the outset of this period. In the long-run, zero- and low carbon resources, including demand-side and storage resources, may provide a majority, if not all of the balancing services needed to both integrate variable energy[9] renewable resources, as well as rapidly respond to sudden failures of major system components (power plants and transmission lines) . However, the zero-carbon technologies that are needed for balancing and

[9] Variable and intermittent are often used interchangeably, but variable more accurately reflects the integration issues of renewable into the California grid. Winds can slow across a wind farm or cloud cover can shade portions of a solar field, temporarily reducing unit or facility output, but not shut down the unit or facility.

contingency response are not expected to be available in sufficient quantities by the early- to mid-2020s to obviate the need for flexible natural gas-fired electricity generation, which can be quickly dispatched as energy and other services are needed. In the interim, state policies serve to (a) limit utility financing and development of new natural gas-fired generation to that needed to reliably operate the electricity system, and (b) require privately-owned generators to participate in the AB 32 cap-and-trade program that is designed to reduce economy-wide GHG emissions in a manner that is as economically efficient as possible.

Given that natural gas-fired generation is needed for reliable system operation, the development and operation of new facilities to replace aging plants, the nuclear facility at San Onofre, and those retiring pursuant to the State Water Resource Control Board's (SWRCB) policy limiting the use of once-through cooling technologies is not only necessary for system and local reliability, such development serves to reduce GHG emissions from the electricity sector. This outcome is discussed in detail below.

The amount of new natural gas-fired capacity needed to provide reliable service to the customers of the state's investor-owned utilities, direct access providers and community choice aggregators over a ten-year planning horizon is determined in the California Public Utilities Commission's (CPUC's) Long-term Procurement Planning (LTPP) proceeding. The resulting portfolio of demand- and supply-side resources satisfies the state's loading order, which mandates development of cost-effective preferred resources (zero- and low-GHG emitting resources, such as energy efficiency, demand response, and renewable generation) in support of the state's climate change policies before authorizing the development/financing of conventional fossil resources.[10] It is also consistent with CPUC direction to investor-owned utilities to procure energy storage resources in support of a high variable generation resource system.[11]

THE ROLE OF NATURAL GAS-FIRED GENERATION IN A LOW-GHG ENVIRONMENT

The need for natural gas-fired generation to reliably operate the electricity system is well established. On October 8, 2008, the Energy Commission adopted an Order Instituting Informational Proceeding (08-GHG OII-1) to solicit comments on how to assess the greenhouse gas impacts of proposed new power plants in accordance with the California Environmental Quality Act (CEQA).[12] A report prepared as a response to the GHG OII (CEC 2009a) indicates the services that natural gas-fired power plants provide in an evolving high-renewables, low-GHG system (CEC 2009b, pp 93 and 94). Among these are (a) variable generation and grid operations support and (b) local capacity.

[10] The loading order is set forth in California's Energy Action Plans. Energy Action Plan I was adopted by the state's energy agencies in April/May 2003 and Energy Action Plan II in September 2005. An update to these plans was issued in February 2008.

[11] D.13-10-040 (October 17, 2013) established a procurement target of 1,325 MW in total for the state's three largest investor-owned utilities.

[12] This need for gas-fired generation to reliably operate the system was reaffirmed in the CPUC decision authorizing Southern California Edison to procure new gas-fired generation in the Los Angeles Basin (D.13-02-015) See *Decision Authorizing Long-Term Procurement for Local Capacity Requirements*, February 13, 2013, p. 2.

Variable Generation and Grid Operations Support

California's renewable portfolio standard (RPS) requires that the state's energy service providers meet 50 percent of retail sales with renewable energy by 2030; meeting GHG emission reduction targets for 2050 will likely require a far higher percentage. Much of this energy will come from variable wind and solar resources to be developed in California, or on an "as generated" basis from neighboring states.

The CA ISO has identified an increased need for regulation services, "load-following" generation, and multi-hour ramping as a result of the increase in these variable ("intermittent energy") renewable resources, whose output changes over the course of the day, often in a sudden and unpredictable fashion. Dispatchable capacity must provide "regulation," small changes in output over a 5-minute period at CA ISO direction, requiring that the generator be equipped with automated generation control (AGC). "Load following" requires larger changes in output by the generation portfolio over a 5-minute to one-hour period. Multi-hour ramping needs require that units be dispatched, at CA ISO direction if necessary, over time periods of one to nine hours and wider ranges of output in aggregate, requiring dispatchable generation that can start and ramp up and down quickly and be capable of operating at relatively low load levels if the amount of dispatchable capacity and associated energy needed from these resources is to be minimized.

Natural gas-fired power plants are currently the only type of new facility that can provide these "ancillary" services in the quantities needed now and in the near future. While dispatchable hydroelectric plants can also provide them, the potential for adding hydroelectric resources to the system is limited. Nuclear, coal and geothermal facilities are generally more economic if operated at or near their design point (i.e., base loaded)[13] and, therefore, are not the preferred technologies for providing load-following and ramping services. While demand-side resources and storage may ultimately provide significant quantities of these services, only pumped hydro storage facilities are currently capable of doing so on a large scale.

Historically, a large share of California's load-following and ramping needs have been provided by the natural gas-fired steam turbines built on the Pacific Coast and in the San Francisco Bay Delta during the 1960s and 1970s. Very efficient when constructed, these provided base load energy through the 1980s and 1990s; they were supplanted in this role by newer, more efficient combined cycle technologies built pursuant to the energy crisis of 2000 – 2001. While these units were modified to operate successfully as load following and peaking generation, they are not as efficient or economic as newer technologies. Several of these facilities have retired as a result of the State Water Resource Control Board's (SWRCB's) policy on the use of OTC technologies; others plan to retire by 2020. This represents a loss of capacity capable of operating at a very wide range of output and thus large quantities of flexible generation and other ancillary services.

[13] Issues can arise from: thermal fatigue due to cycling; difficulties starting and stopping solid or geothermal fuel supplies; significant inefficiencies at low loads or standby points used to avoid full shutdowns; and, significant capital outlays that make it necessary to operate the units as much as possible.

Local Capacity Requirements

The CA ISO has identified numerous local capacity areas (LCA) and sub-areas in which threshold amounts of capacity are required to ensure reliability. Transmission constraints prevent the import of sufficient energy into these areas under high load conditions to ensure reliable service without requiring specified amounts of local capacity be generating or available to the CA ISO for immediate dispatch.

Reliable service requires that the CA ISO be able to maintain service under 1-in-10-year load conditions given the sequential failure of two major components (a large power plant and a major transmission line, for example); this requirement is imposed by the North American Electric Reliability Council (NERC). The amount of capacity needed in each of these areas (the local capacity requirement, or "LCR") is determined annually by the CA ISO; the LCR study process culminates in an annual *Local Capacity Technical Analysis*. The LCRs of the Los Angeles Basin, San Diego and Big Creek-Ventura LCAs are too large to be met solely with non-natural gas fired generation, as evidenced by the procurement authorization issued in the 2012 LTPP proceeding (see below).

QUANTIFYING THE NEED FOR NATURAL GAS-FIRED GENERATION

Prior to the deregulation of the California electricity system during the 1990's, the Energy Commission's power plant siting process considered the need for power plant development. SB 110 (Chapter 581, Statutes of 1999) eliminated the requirement that projects licensed by the Energy Commission be in conformance with an integrated assessment of need that was conducted by the Energy Commission until that time.

The need for new generation capacity to ensure reliable service in the investor-owned utility (IOU) service territories is now determined in the CPUC's biennial LTPP proceeding.[14] This proceeding is the forum in which the state's major IOUs are authorized to finance the development of new "least-cost, best-fit" generation (on behalf of either IOU customers or all ratepayers not served by publicly-owned utilities) needed to reliably meet electricity demand. This need, specified in terms of: (a) the MW of capacity needed; (b) the desired or required operating characteristics of the resource(s) to be financed; and (c) the location of proposed additions if required for local reliability, is a function of planning assumptions that reflect the state's commitment to dramatically reduce GHG emissions from the electricity sector. The MWs of capacity needed are driven by:

- Peak demand growth due to economic and demographic factors;
- Reductions in peak demand due to committed and uncommitted energy efficiency and demand response programs;

[14] The need for new generation capacity to ensure reliable service by publicly-owned utilities (POU) is determined by the governing authorities of the individual utilities.

- Reserve margins (dependable capacity in excess of peak demand) needed to ensure system reliability, normally assumed to be 15 to 17 percent of peak demand, but also including any additional dispatchable capacity needed to ensure reliability given variation in the output of renewable resources (e.g., wind or solar generation);
- Capacity to be provided by fossil-fired resources being developed by California-based investor-owned utilities pursuant to authorization by the CPUC in previous LTPP proceedings;
- Capacity to be provided by new renewable resources built/contracted with to meet the state's RPS; and,
- Capacity to be lost due to retirement, for example, capacity expected to cease operation as a result of the SWRCB policy regarding the use of OTC.

The planning assumptions adopted for use in the LTPP proceeding, and thus determinant of the amount of new capacity authorized, consider both the state's loading order for resource development, as well as the expected development of specific types of preferred resources, including energy efficiency, demand response, and renewable generation. In other words, in authorizing the procurement/financing of dispatchable, natural gas-fired capacity by an IOU, the CPUC assumes that all cost-effective amounts of preferred resources will have been procured.

Authorization for Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) to procure natural gas-fired generation or other least-cost resources to replace retiring once-through cooled generation units and the San Onofre Nuclear Generating Station was granted in D.13-02-015 (February 13, 2013) and D.14-03-004 (March 13, 2014) in the CPUC's 2012 LTPP proceeding (R.12-03-014). The decisions authorized SCE to procure a minimum of 1,000 MW and up 1,500 MW of new gas-fired generation capacity in the Los Angeles Basin LCA and up to 290 MW in the Moorpark sub-area of the Big Creek – Ventura LCA, and for SDG&E to procure up to 600 MW in the San Diego LCA.

The CPUC does not require Energy Commission certification for a generation project to participate in a utility request for offers (RFOs), nor does the Energy Commission require a contract with a utility for a merchant project to be considered for certification. Requiring the sequencing of these processes would not only lengthen the time needed to bring projects on line and thus threaten system reliability, it would reduce the number of projects that could compete in utility RFOs. This could lead to non-competitive solicitations, unnecessarily raising ratepayer costs.

Energy Commission certification of fossil generation without a utility contract does not result in the development of more fossil generation than that needed to reliably operate the system. It is not expected that developers of new capacity, such as the developer of AEC, would bring a project to completion without a contract, which would guarantee recovery of the investment of several hundred million dollars. No merchant plant has been developed since the energy crisis (2000 – 2001) without a contract. This plant, in turn, provides energy, capacity and ancillary services that obviate the need for other, new gas-fired generation and contributes to reduction in GHG emissions. Even if AEC were to be constructed and operated without CPUC approval of a utility contract, it would still: (a) displace energy from higher GHG-emission facilities (see below), and (b) not "crowd out" renewable generation and demand-side programs, as requirements for the procurement of these preferred resources would be unaffected.

THE IMPACT OF AEC ON GHG EMISSIONS FROM THE ELECTRICITY SECTOR

Any assessment of the impact of a new power plant on system-wide GHG emissions must begin with the understanding that electricity generation and demand must be in balance at all times; the energy provided by any new generation resource simultaneously displaces exactly the same amount of energy from an existing resource or resources. The GHG emissions produced by AEC are thus not incremental additions to system-wide emissions, but are offset by reductions in GHG emissions from those generation resources that are displaced. The operation of the system so as to meet the demand for electricity at the lowest cost in fact leads to a reduction in system-wide GHG emissions if AEC is added.

At low to moderate penetration levels of renewable generation, new natural gas-fired plants such as AEC displace less efficient natural gas-fired generation[15] in a very straightforward fashion. It is reasonable to assume that AEC would be dispatched (called upon to generate electricity) whenever they are a cheaper source of energy than an alternative - i.e., that they will displace a more expensive resource, if not the most expensive resource that would otherwise be called upon to operate. The costs of dispatching a power plant are largely the costs of fuel, plus variable operations and maintenance (O&M) costs, with the former representing the lion's share of such costs (90 percent or more). It follows that AEC would be dispatched when it burns less fuel per MWh than the resource(s) it displaces, i.e., when it produces fewer GHG emissions. There are exceptions in theory, but not in practice.[16]

[15] At very low gas prices relative to coal prices, i.e., when electricity from natural gas is cheaper than that from coal, new gas-fired generation will displace coal-fired generation, leading to even greater reductions in GHG emissions. In markets such as California, where GHG emissions allowance costs are a component of the market price, coal-fired generation is displaced even sooner due to its higher carbon content. The development and operation of AEC would not lead to the displacement of energy from zero-carbon generation such as that of renewable, large hydro or nuclear facilities. These have zero (or, in the case of nuclear, very low) fuel costs and will still be dispatched before natural gas-fired generation.

[16] If a plant's variable O&M costs are so low as to offset the costs associated with its greater fuel combustion, a less efficient (higher GHG emission) plant may be dispatched first. There is no indication that AEC has unusually low variable O&M costs and would be dispatched before a more efficient facility. In addition, if a natural gas-fired plant's per-mmBtu fuel costs are very low, it may be less efficient (higher

In the longer-term, the development and operation of AEC, ultimately leads to the retirement of less-efficient (higher-emitting) generation. By reducing their revenue streams (for the provision of both energy and capacity-related services, whether through markets or under a bilateral contract), AEC would render these other facilities less profitable and riskier to operate. This follows from the fixed demand for energy and ancillary services; the developers of AEC cannot stimulate demand for energy and other products they provide, but merely provide a share of the energy that is needed to meet demand and the capacity needed to reliably operate the system. In doing so, AEC both discourages the use of, and allows for the retirement of less-efficient generation.

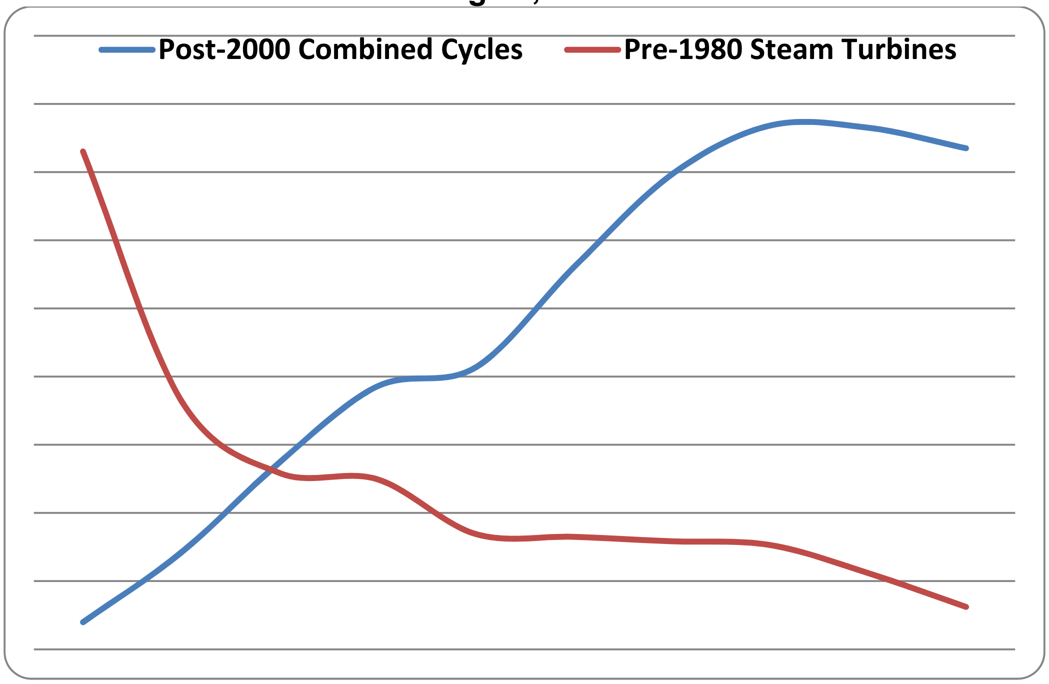
The long-run impact of the natural gas-fired fleet turnover as described here can be seen from historical changes in resources that are providing electricity in California as presented below in **Greenhouse Gas Figure 1** (data includes combined cycles and boilers only). In 2001, approximately 74,000 GWh (62.5 percent of natural gas-fired generation) in California was from pre-1980 natural gas fired steam turbines, combusting an average of 11,268 Btu per kWh (not shown in the figure). By 2010, this share had fallen to approximately 6,000 GWh (5.4 percent); 64.1 percent of natural-gas fired generation was from new combined cycles with an average heat rate of 7,201 Btu per kWh (CEC 2011, also not shown in the figure).[17] The net change over this period was a 22 percent reduction in GHG emissions (also not shown in the figure) despite a 3.5 percent increase in generation. The post-2000 development of new combined-cycle generation has allowed for the retirement of aging natural gas-fired steam turbines along the California Coast and in the San Francisco Bay Delta. Those that remain in operation have seen a dramatic reduction in their capacity factors[18] and primarily as a source of dispatchable capacity, used only during highest-demand hours and when needed to reliably operate the system.

GHG emitting) but still be dispatched first. Natural gas costs in California, however, are higher than elsewhere in the WECC; thus this scenario is very unlikely to occur.

[17] The remaining 30 percent of natural-gas-fired generation is largely cogeneration; slightly more than one percent is from peaking units. For a detailed discussion of the evolution of natural gas-fired generation in California since 2000, see *Thermal Efficiency of Gas-Fired Generation in California: 2012 Update* (CEC-200-2013-002; May 2013)

[18] A unit's capacity factor is its output expressed as a share of potential output, the amount it would generate if it were operated continuously at 100 percent of its maximum capacity for every hour of the year.

Greenhouse Gas Figure 1
Annual California Output (GWh), Selected Natural Gas-Fired Generation Technologies, 2001 – 2010



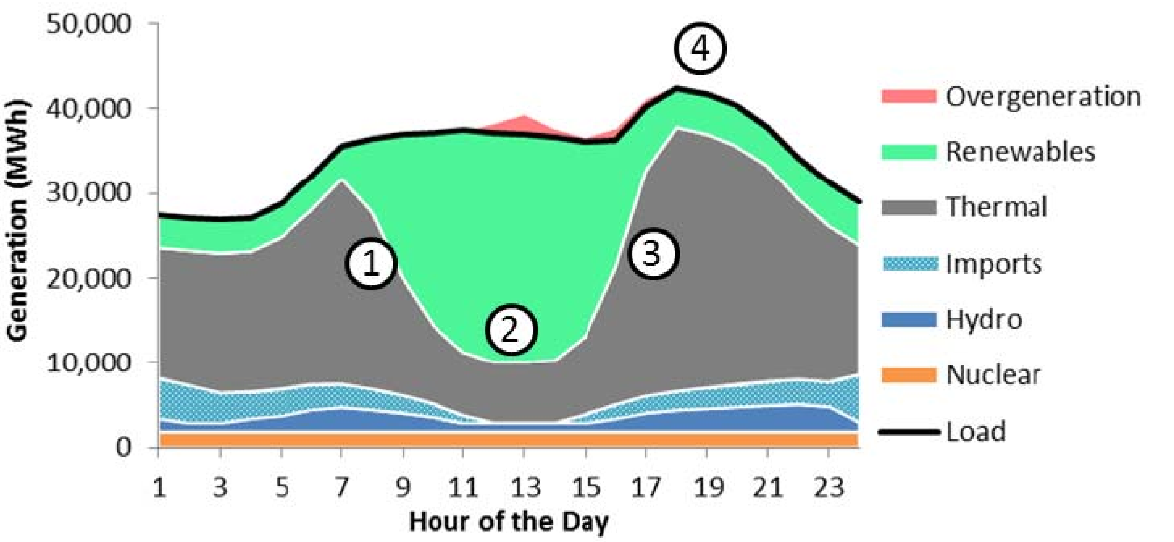
Source: Generator Quarterly Fuel and Report Filings with the Energy Commission

The relationship between a natural gas-fired plant's heat rate and its dispatch in the real world is in fact more complicated than that described above. While natural gas-fired plants differ in their thermal efficiency – the amount of fuel combusted, and thus GHG emissions per unit of electricity generated –natural gas plants *that are very efficient when run at maximum output* are not necessarily dispatched before less efficient ones. While this would seem to contradict the assertion that output from a new plant will always displace a higher emitting one, a plant that is less efficient (in other words, has a higher heat rate) may actually combust less fuel during a duty cycle than a plant with a lower heat rate, and thus produce fewer GHG emissions. Consider a 30-MW peaking plant with a heat rate of 10,000 Btu/kWh when operated at full output that can be turned on quickly, generating approximately 15 to 30 MW in a matter of minutes. Use of this plant to meet contingency needs (e.g., demand on a hot afternoon) may result in less incremental fuel combustion than a 100 MW plant with a lower heat rate at full output if the latter requires several hours and combusts large amounts of fuel to start up, must be kept on overnight or for several hours in order to be available later the same day or the next day, and/or cannot operate at 30 MW without a marked degradation in thermal efficiency (and thus increases in GHG emissions). As a result, a resource such as AEC, which has sacrificed some degree of thermal efficiency at full load in order to provide additional flexibility (multiple starts and shutdowns, faster starts and ramp rates,[19] lower minimum operating levels) may produce fewer GHG gas emissions in providing the same services as a gas-fired alternative with a lower full-load heat rate.

[19] A generator's ramp rate indicates how quickly (MW/minute) it can change output levels.

At higher levels of renewable energy penetration, such as that necessary to meet California's 2030 renewable portfolio standard of 50 percent, relatively efficient fast-start, fast-ramping resources such as AEC further contribute to GHG emission reductions by increasing the amount of renewable energy that can be integrated into the electricity system. This can be seen in **Greenhouse Gas Figure 2,** which depicts the estimated operating profile of the generating resources of the high-solar electricity system that California will increasingly have over the next 15 years and beyond. Much of the additional renewable energy will come from solar resources even if there is limited development of utility-scale solar generation, as the residential and commercial sectors take advantage of falling distributed solar costs and new residential construction post-2020 is required to be zero-net energy, i.e., include solar panels.

Greenhouse Gas Figure 2
California Generation Typical for a Non-Summer Day ("Duck" Chart)



The large "belly" (Number 2 in the figure) represents solar generation on a typical non-summer day; this gets larger over time as more solar is added to the system. The gray area represents necessary thermal generation, which is increasing natural gas over time as California portfolios are divested of coal pursuant to the state's Emissions Performance Standard. Note that imports are reduced to zero at mid-day, and hydro generation is limited to run-of-river (from hydro-generation facilities that do not have water storage, and from water that must be allowed to flow due to recreational needs, flood control, habitat preservation, etc.). A share of mid-day generation must also be thermal/natural gas as a threshold amount of thermal capacity needs to be idling at mid-day at minimum output to (a) protect against sudden component failures (major power plants and transmission lines); and (b) in order to be generating 4-8 hours later when solar energy is unavailable.

Greenhouse Gas Figure 2 illustrates a case of over-generation (the orange section above the load curve), in which renewable output at mid-day and necessary gas-fired generation jointly result in too much energy being produced. There are several ways to deal with over-generation. In theory, the surplus energy can be exported to neighboring states. But much of the over-generation expected in California will occur during the low-demand months of February - April, when similar surpluses exist In the Pacific Northwest due to the snow-melt and the resulting increase in hydroelectric generation in the Columbia River basin. Under these conditions, export potential is likely to be limited and export prices would be near zero. The long-term solution for over-generation is expected to be the development of cost-effective multi-hour storage, allowing the surplus to be stored until it can be used in evening hours. In the interim, however, over-generation can only be dealt with by curtailing renewable generation or reducing the amount of gas-fired generation that is needed during mid-day and early afternoon hours. The latter is facilitated by developing gas-fired resources capable of starting up quickly and/or operating at lower minimum load levels.[20] While AEC is less thermally efficient than the natural gas-fired combined cycles built in California during the past decade, AEC is capable of operating at lower levels of output, and doing so without a marked decrease in efficiency. Moreover, it can be off line until shortly before being needed in the late afternoon and early evening, As a result, it can allow for more renewable generation than a conventional combined cycle, with the concomitant reduction in GHG emissions serving to offset the impact of its lower efficiency at full output.

AVENAL PRECEDENT DECISION

The Energy Commission established a precedent decision in the Final Commission Decision for the Avenal Energy Project (CEC 2009b), finding as a conclusion of law that any new natural gas-fired power plant certified by the Energy Commission "must:

- not increase the overall system heat rate for natural gas plants;
- not interfere with generation from existing renewables or with the integration of new renewable generation; and
- take into account the two preceding factors, reduce system-wide GHG emissions"[21]

The average heat rate for the Western Electricity Coordinating Council (WECC) is presented in **Greenhouse Gas Table 4**.

[20] For a detailed discussion of the operational needs for a high-solar portfolio, see Energy and Environmental Economics, *Investigating a Higher Renewables Standard in California*, January 2014, available at http://www.ethree.com/public_projects/renewables_portfolio_standard.php.
[21] Final Commission Decision, Avenal Energy Application for Certification (08-AFC-1) December 2009, p. 114.

Greenhouse Gas Table 4
Weighted Average Heat Rate for Operating Natural Gas-Fired Plants[1] in the WECC
2010-2012

Year	Average Heat Rate (mmBtu/kWh)
2010	7,784
2011	7,995
2012	7,918

[1] Excludes cogeneration facilities
Source: Ventyx, Velocity Suite (compiled from EPA hourly Continuous Emission Monitoring Survey data

While the exact heat rate of AEC will depend upon how it is dispatched, its operation will result in a reduction in the system heat rate for natural gas plants in the WECC due to its displacing energy from less-efficient natural gas-fired generation as discussed above. In those instances where AEC is higher emitting on a per-MWh basis than the resources it displaces but does so because it can operate at lower output levels and thus allow for more renewable integration and generation, the result might be a higher system heat rate, but total gas-fired generation and GHG emissions will fall.

As noted above, the addition of AEC would not interfere with generation from existing renewable facilities or with the integration of new renewable generation. The flexible nature of AEC would in fact serve to facilitate the integration of additional variable renewable resources.

AEC would reduce system-wide GHG emissions as discussed above; its development is consistent the goals and policies of AB 32 and thus are consistent with the Avenal precedent decision.

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ACRONYMS

AB	Assembly Bill
ARB	California Air Resources Board
CAA	Clean Air Act
CalEPA	California Environmental Protection Agency
California ISO	California Independent System Operator
CCCC	California Climate Change Center
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CPUC	California Public Utilities Commission
EIR	Environmental Impact Report
EPS	Emission Performance Standard
GCC	Global Climate Change
GHG	Greenhouse Gas
GWh	Gigawatt-hour
GWP	Global Warming Potential
HBEP	Huntington Beach Energy Project
HFC	Hydrofluorocarbons
HSC	Health and Safety Code
IEPR	Integrated Energy Policy Report
IPCC	Intergovernmental Panel on Climate Change
LCA	Local Capacity Area
LTPP	Long-term Procurement Planning
MT	Metric tones
$MTCO_2e$	Metric Tons of CO_2-Equivalent
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous Oxide
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NOx	Oxides of Nitrogen or Nitrogen Oxides
NSPS	New Source Performance Standard

OTC	Once-Through Cooling
PFC	Perfluorocarbons
PSA	Preliminary Staff Assessment
PSD	Prevention of Significant Deterioration
RPS	Renewables Portfolio Standard
SB	Senate Bill
SF_6	Sulfur hexafluoride
SWRCB	State Water Resource Control Board
U.S. EPA	United States Environmental Protection Agency
WCI	Western Climate Initiative

PUBLIC HEALTH

Testimony of Huei-An (Ann) Chu, Ph.D.

SUMMARY OF CONCLUSIONS

California Energy Commission staff has analyzed the potential human health risks associated with construction, demolition, and operation of the proposed Alamitos Energy Center (AEC). Staff's analysis of potential health impacts was based on a highly conservative health protective methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the project's toxic air emissions.

INTRODUCTION

The purpose of this section of the Final Staff Assessment (FSA) is to determine if emissions of toxic air contaminants (TACs) from the proposed AEC would have the potential to cause significant adverse public health impacts or to violate thresholds for the protection of public health. If potentially significant health impacts are identified, staff would identify and recommend mitigation measures necessary to reduce such impacts to insignificant levels.

In addition to the analysis contained in this **Public Health** section that focuses on potential effects to the public from emissions of toxic air contaminants, Energy Commission staff address the potential impacts of regulated, or criteria, air pollutants in the **Air Quality** section of this FSA and assess the impacts on public and workers health from accidental releases of hazardous materials in the **Hazardous Materials Management** and **Worker Safety and Fire Protection** sections. The health and nuisance effects from electric and magnetic fields are discussed in the **Transmission Line Safety and Nuisance** section. Pollutants released from the project's wastewater streams are discussed in the **Soil and Water section**. Releases in the form of hazardous and nonhazardous wastes are described in the **Waste Management** section.

LAWS, ORDINANCES, REGULATIONS, AND STANDARDS (LORS)

Public Health Table 1 lists the federal, state, and local laws, ordinances, regulations, and standards (LORS) applicable to the control of TAC emissions and mitigation of public health impacts for AEC. This FSA evaluates compliance with these LORS.

Public Health Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable LORS	*Description*	*Compliant?*	*Basis for Compliance*
Federal			
Clean Air Act section 112 (Title 42, U.S. Code section 7412)	Section 112 of the Clean Air Act addresses emissions of hazardous air pollutants (HAPs). This act requires new sources that emit more than 10 tons per year of any specified HAP or more than 25 tons per year of any combination of HAPs to apply Maximum Achievable Control Technology (MACT).	Yes	The total combined formaldehyde emissions from all sources is 5.08 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 11.31 tpy, which is less than 25 tpy. Therefore, this section is not applicable to AEC.
40 Code of Federal Regulations (CFR) Part 63 Subpart YYYY (National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines)	This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.	Yes	The total combined formaldehyde emissions from all sources is 5.08 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 11.31 tpy, which is less than 25 tpy. Therefore, this subpart is not applicable because AEC would not be a major source for HAPs emissions.
State			
California Health and Safety Code section 25249.5 et seq. (Proposition 65)	These sections establish thresholds of exposure to carcinogenic substances above which Proposition 65 exposure warnings are required.	Yes	Please see Significant Criteria below for detailed discussion.
California Health and Safety Code, Article 2, Chapter 6.95, Sections 25531 to 25541; California Code of Regulations Title 19 (Public Safety), Division 2 (Office of Emergency Services), Chapter 4.5 (California Accidental Release Prevention Program)	These sections require facilities storing or handling significant amounts of acutely hazardous materials to prepare and submit Risk Management Plans.	Yes	Please see discussion of Hazardous Materials Handling Program in Hazardous Material Management section.

Applicable LORS	Description	Compliant?	Basis for Compliance
California Health and Safety Code section 41700	This section states that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause 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.”	Yes	There would be no significant health impacts from the project’s toxic air emissions.
California Health and Safety Code Sections 44300 et seq.	Air Toxics Hot Spots Program requires participation in the inventory and reporting program at the local air pollution control district level.	Yes	According to South Coast Air Quality Management District (SCAQMD)‘s Preliminary Determination of Compliance (PDOC) and Final Determination of Compliance (FDOC), this project meets this LORS.
California Health and Safety Code Sections 44360 to 44366 (Air Toxics “Hot Spots” Information and Assessment Act—AB 2588)	These sections require that, based on results of a health risk assessment (HRA) conducted per ARB (California Air Resources Board) / OEHHA (Office of Environmental Health Hazard Assessment) guidelines, toxic contaminants do not exceed acceptable levels.	Yes	The maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the AEC estimated independently by the applicant, staff, and the SCAQMD are all below levels of significance
California Public Resource Code section 25523(a); Title 20 California Code of Regulations section 1752.5, 2300–2309 and Division 2 Chapter 5, Article 1, Appendix B, Part (1); California Clean Air Act, Health and Safety Code section 39650, et seq.	These sections require a quantitative health risk assessment for new or modified sources, including power plants that emit one or more toxic air contaminants (TACs).	Yes	A quantitative health risk assessment was conducted for AEC.
Local			
South Coast Air Quality Management District (SCAQMD) Rule 1401 (New Source Review of Toxic Air Contaminants)	This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permit units which emit toxic air contaminants (TACs).	Yes	The maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) are all below levels of significance.

Applicable LORS	Description	Compliant?	Basis for Compliance
SCAQMD Rule 1403 (Asbestos Emissions from Demolition/Renovation Activities)	This rule specifies work practice requirements that would limit asbestos emissions from building demolition and renovation activities, including removal and associated disturbance of asbestos-containing materials.	Yes	The applicant would comply with this LORS. Please see Asbestos below for detailed discussion.
SCAQMD Rule 212(c)(3) (Permits – Public Notice)	This rule requires public notification if the maximum individual cancer risk (MICR), based on Rule 1401, exceeds one in 1 million (1×10^{-6}), due to a project's proposed construction, modification, or relocation for facilities with more than one permitted source, unless the applicant can show the total facility-wide MICR is below 10 in 1 million (10×10^{-6}).	Yes	Both the maximum individual cancer risk (MICR) and the total facility-wide MICR are below levels of significance

SETTING

Characteristics of the natural environment, such as meteorology and terrain, affect the project's potential for impacts on public health. An emission plume from a facility would affect elevated areas before lower terrain areas because of reduced opportunity for atmospheric mixing. Consequently, areas of elevated terrain can often be subjected to increased pollutant impacts compared to lower-level areas. Also, the land use around a project site can influence impacts due to population distribution and density, which, in turn, can affect public exposure to project emissions. Additional factors affecting potential public health impacts include existing air quality and environmental site contamination.

SITE AND VICINITY DESCRIPTION

The proposed AEC site is located at the city of Long Beach, California, within the South Coast Air Quality Management District (SCAQMD).

According to the Application for Certification (AFC), approximately 584,644 residents live within a 6-mile radius of AEC, and the sensitive receptors within a 6-mile radius of the project site include (AEC 2015i, Section 5.9.2):

- 651 preschool/daycare centers
- 21 nursing homes
- 177 schools
- 739 hospitals, clinics, and/or pharmacies
- 8 colleges
- 1 arena
- 2 prisons

Sensitive receptors, such as infants, the aged, and people with specific illnesses or diseases, are the subpopulations which are more sensitive to the effects of toxic substance exposure. The nearest sensitive receptor is the Rosie the Riveter Charter High School, a privately owned and operated school located on the AGS site, approximately 971 feet (296 meters) from the nearest proposed stack location. The second closest sensitive receptor is Kettering Elementary, which is approximately 2,297 feet (700 meters) northwest of the nearest proposed stack location. Apart from the Rosie the Riveter Charter High School and Kettering Elementary, there are no other schools within approximately 0.5 mile of the AEC project site. The nearest residents are located approximately 1,165 feet (355 meters) west of the proposed stack locations along E. Mariquita Street and approximately 1,329 feet (405 meters) east of the proposed stack locations along Nassau Drive. The nearest businesses are located approximately 525 feet (160 meters) east of the AEC site (AEC 2015i, Section 5.9.2).

METEOROLOGY AND CLIMATE

Meteorological conditions, including wind speed, wind direction, and atmospheric stability, affect the extent to which pollutants are dispersed into the air and the direction of pollutant transport. This, in turn, affects the level of public exposure to emitted pollutants along with the associated health risks. When wind speeds are low and the atmosphere is stable, for example, dispersion is reduced and localized exposures may be increased.

Atmospheric stability is one characteristic related to turbulence, or the ability of the atmosphere to disperse pollutants from convective air movement. Mixing heights (the height marking the region within which the air is well mixed below the height) are lower during mornings because of temperature inversions. These heights increase during warm afternoons. Staff's **Air Quality** section presents a more detailed description of meteorological data for the area.

EXISTING PUBLIC HEALTH CONCERNS

The proposed AEC site is located in Los Angeles County, within the South Coast Air Basin (SCAB) and within the South Coast Air Quality Management District (SCAQMD).

When evaluating a new project, staff usually conducts a study and analysis of existing public health issues in the project vicinity (i.e. areas within the same county). This analysis is prepared in order to identify the most current status of respiratory diseases (including asthma), cancer, and childhood mortality rates in the population located within the same county or air basin of the proposed project site. Such assessment of existing health concerns provides staff with a basis on which to evaluate the significance of any additional health impacts from the proposed AEC and assess the need for further mitigation. The public health information below is the most current available.

By examining average toxic concentration levels from representative air monitoring sites, together with cancer risk factors specific to each carcinogenic contaminant, a lifetime cancer risk can be calculated to provide a background risk level for inhalation of ambient air.

Cancer

When examining such risk estimates, staff considers it important to note that the overall lifetime risk of developing cancer for the average male in the United States is about 1 in 2, or 500,000 in 1 million and about 1 in 3, or 333,333 in 1 million for the average female (American Cancer Society 2014).

From 2008 to 2012, the cancer incidence rates in California were 48.56 in 1 million for males and 39.48 for females. Also, from 2008 to 2012, the cancer death rates for California are 18.34 in 1 million for males and 13.53 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2016, Table 4 and Table 5).

By examining the State Cancer Profiles presented by the National Cancer Institute, staff found that cancer death rates in Los Angeles County have been falling between 2008 and 2012. These rates (of 15.13 per 1,000,000, combined male/female) were somewhat lower than the statewide average of 15.51 per 1,000,000 (National Cancer Institute 2016).

According to the County Health Status Profiles 2015, the death rate due to all cancers, from 2011-2013, is 14.12 in 1 million for Los Angeles County, slightly lower than the cancer death rate (15.09 in 1 million) for California (CDPH 2015).

Lung Cancer

As for lung and bronchus cancers, from 2008 to 2012 the cancer incidence rates in California were 5.58 in 1 million for males and 4.21 in 1 million for females. Also, from 2008 to 2012 the cancer death rates for California were 4.37 in 1 million for males and 3.05 in 1 million for females (American Cancer Society, Cancer Facts & Figures 2016, Table 4 and Table 5).

According to the County Health Status Profiles 2015, the death rate due to lung cancers (not including bronchus cancer), from 2011-2013, is 2.98 in 1 million for Los Angeles County, slightly lower than the cancer death rate (3.36 in 1 million) for California (CDPH 2015).

From a publication of the Los Angeles County Department of Public Health (LACDPH 2011), of cancer deaths, lung cancer was the most common one (2,908 deaths; mortality rate 3.1 per 1,000,000 population) in Los Angeles County.

Asthma

The asthma diagnosis rates in Los Angeles County are lower than the average rates in California for both adults (age 18 and over) and children (ages 1-17). The percentage of adults in Los Angeles County diagnosed with asthma was reported as 6.6 percent in 2005-2007, compared to 7.7 percent for the general California population. Rates for children for the same 2005-2007 period were reported as 9.3 percent in Los Angeles County compared to 10.1 percent for the state in general (Wolstein et al. 2010).

Air Toxics Emission Estimates

There are some ambient monitoring sites for TACs in the SCAB. Air quality and health risk data in Table C-20 of California Almanac of Emissions and Air Quality – 2009 Edition (ARB 2009) are for SCAB for years 1990 - 2005. The data show a downward trend in TAC annual average concentrations, along with related cancer risks (ARB 2009). No TAC emissions and their health risks were reported in the 2013 Edition (ARB 2013).

The Multiple Air Toxics Exposure Study II and III (MATES II and III) have been conducted in the SCAB by the SCAQMD staff. MATES II and III consisted of a comprehensive monitoring program, an updated emissions inventory, and a modeling effort to characterize health risks associated with human exposures to ambient concentrations of TACs in the SCAB. Both the MATES II and MATES III studies showed that mobile sources, such as cars, trucks, trains, ships, and aircraft, represent the greatest contributors to estimated health risks in Los Angeles County.

About 70 percent of all carcinogenic risk is attributed to diesel particulate matter (DPM) emissions in MATES II, while about 84 percent of all carcinogenic risk is attributed to DPM emissions in MATES III. Overall, the general trend in risk exposure has been decreasing with the estimated cancer risk from exposure to airborne toxics (AEC 2015i, Section 5.9.2). The comparison of the county-wide population-weighted risk in Table 4-5 in the final report of MATES III showed the TAC reductions that occurred in Los Angeles County. The risk reduced from 1,047 per million in 1998 to 951 per million in 2005. SCAB data followed the same trend, showing that TACs decreased from 931 per million in 1998 to 853 per million in 2005 (MATES III 2008).

As a follow-up to the MATES II and III studies, SCAQMD commenced a fourth MATES study (MATES IV) in 2012. The final report of MATES IV was published May 1, 2015. The results of MATES IV study showed a continuing downward trend in TACs. The comparison of county-wide population-weighted risk in Table 4-5 in the final report of MATES IV shows TAC reductions that occurred in Los Angeles County, with values decreasing from 951 per million in 2005 to 415 per million in 2012. South Coast Air Basin (SCAB) data follow the same trend, with corresponding TACs decreasing from 853 per million in 2005 to 367 per million in 2012 (MATES IV 2015).

ASSESSMENT OF IMPACTS AND DISCUSSION OF MITIGATION

METHOD AND THRESHOLD FOR DETERMINING SIGNIFICANCE

This section discusses toxic air contaminant (TAC) emissions to which the public could be exposed during project construction/demolition and routine operation. Following the release of TACs into the air, water or soil, people would come into contact with them through inhalation, dermal contact, or ingestion via contaminated food, water or soil.

Air pollutants for which no ambient air quality standards have been established are called non-criteria pollutants. Unlike criteria pollutants such as ozone, carbon monoxide, sulfur dioxide, or nitrogen dioxide, non-criteria pollutants have no ambient (outdoor) air quality standards that specify health-based levels considered safe for everyone[1]. Since non-criteria pollutants do not have such standards, a health risk assessment (HRA) is used to determine if people might be exposed to those types of pollutants at unhealthy levels.

The standard approach currently used for a HRA involves four steps: 1) hazard identification, 2) exposure assessment, 3) dose-response assessment and 4) risk characterization (OEHHA 2003). These four steps are briefly discussed below:

1. **Hazard identification** is conducted to determine the potential health effects that could be associated with project emissions. For air toxics sources, the main purpose is to identify whether or not a hazard exists. Once a hazard has been identified, staff evaluates the exact toxic air contaminant(s) of concern and determines whether a TAC is a potential human carcinogen or is associated with other types of adverse health effects.

[1] Carbon dioxide (CO_2) is also a non-criteria pollutant, but it is also not considered a TAC at normal concentrations and is not evaluated in this analysis.

2. An **exposure assessment** is conducted to estimate the extent of public exposure to project emissions, including: (1) the worst-case concentrations of project emissions in the environment using dispersion modeling; and (2) the amount of pollutants that people could be exposed to through inhalation, ingestion, and dermal contact. Therefore, this step involves emissions quantification, modeling of environmental transport and dispersion, evaluation of environmental fate, identification of exposure routes, identification of exposed populations and sensitive subpopulations, and estimation of short-term and long-term exposure levels.

3. A **dose-response assessment** is conducted to characterize the relationship between exposure to an agent and incidence of an adverse health effect in exposed populations. The assumptions and methodologies of dose-response assessment are different between cancer and noncancer health effects. In cancer risk assessment, the dose-response relationship is expressed in terms of a potency (or slope) factor that is used to calculate the probability of getting cancer associated with an estimated exposure. In cancer risk assessment, it is assumed that risk is directly proportional to dose. It is also assumed that there is no threshold for carcinogenesis. In non-cancer risk assessment, dose-response data developed from animal or human studies are used to develop acute and chronic non-cancer Reference Exposure Levels (RELs). The acute and chronic RELs are defined as the concentration at which no adverse non-cancer health effects are anticipated. Unlike cancer health effects, non-cancer acute and chronic health effects are generally assumed to have thresholds for adverse effects. In other words, acute or chronic injury from a TAC would not occur until exposure to the pollutant has reached or exceeded a certain concentration (i.e., threshold).

4. **Risk characterization** is conducted to integrate the health effects and public exposure information and to provide quantitative estimates of health risks resulting from project emissions. Staff characterizes potential health risks by comparing worst-case exposure to safe standards based on known health effects.

   Staff conducts its public health analysis by evaluating the information and data provided in the AFC by the applicant. Staff also relies upon the expertise and guidelines of the California Environmental Protection Agency (Cal/EPA) Office of Environmental Health Hazard Assessment (OEHHA) in order to identify: (1) contaminants that cause cancer or other noncancer health effects, and (2) the toxicity, cancer potency factors and non-cancer RELs of these contaminants. Staff relies upon the expertise of the California Air Resources Board (ARB) and the local air districts to conduct ambient air monitoring of TACs and on the California Department of Public Health to evaluate pollutant impacts in specific communities. It is not within the purview or the expertise of the Energy Commission staff to duplicate the expertise and statutory responsibility of these agencies.

For each project, a screening-level risk assessment is initially performed using simplified assumptions that are intentionally biased toward protection of public health. That is, staff uses an analysis designed to overestimate public health impacts from exposure to project emissions. In reality, it is likely that the actual risks from the source in question would be much lower than the risks as estimated by the screening-level assessment. The risks for such screening purposes are based on examining conditions that would lead to the highest, or worst-case, risks and then using those assumptions in the assessment. Such an approach usually involves the following:

- using the highest levels of pollutants that could be emitted from the plant;
- assuming weather conditions that would lead to the maximum ambient concentration of pollutants;
- using the type of air quality computer model which predicts the greatest plausible impacts;
- calculating health risks at the location where the pollutant concentrations are estimated to be the highest;
- assuming that an individual's exposure to carcinogenic (cancer-causing) agents would occur continuously for 30[2] years; and
- using health-based objectives aimed to protect the most sensitive members of the population (i.e., the young, elderly, and those with respiratory illnesses).

A screening-level risk assessment would, at a minimum, include the potential health effects from inhaling hazardous substances. Some facilities would also emit certain substances (e.g. semi-volatile organic chemicals and heavy metals) that could present a health hazard from non-inhalation pathways of exposure (OEHHA 2003, Tables 5.1, 6.3, 7.1). When these multi-pathway substances are present in facility emissions, the screening-level analysis would include the following additional exposure pathways: soil ingestion, dermal exposure, consumption of locally grown plant foods, mother's milk and water ingestion[3] (OEHHA 2003, p. 5-3).

The HRA process addresses three categories of health impacts: (1) acute (short-term) health effects, (2) chronic (long-term) noncancer effects, and (3) cancer risk (also long-term). They are discussed below.

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[2] It used to be assumed 70 years. However, in 2015 Guidance, OEHHA recommends that an exposure duration (residency time) of 30 years be used to estimate individual cancer risk for the maximally exposed individual resident (MEIR). In addition, for the maximally exposed individual worker (MEIW), OEHHA now recommends using an exposure duration of 25 years to estimate individual cancer risk for off-site workers (OEHHA 2015, Table 8.5).

[3] The HRA exposure pathways for AEC included inhalation, dermal absorption, soil ingestion, home grown produce and mother's milk, not including water ingestion because water sources are not impacted by AEC.

Acute Noncancer Health Effects

Acute health effects are those that result from short-term (one-hour) exposure to relatively high concentrations of pollutants. Such effects are temporary in nature and include symptoms such as irritation of the eyes, skin, and respiratory tract.

Chronic Noncancer Health Effects

Chronic noncancer health effects are those that result from long-term exposure to lower concentrations of pollutants. Long-term exposure has been defined as more than 12 percent of a lifetime, or about 8 years (OEHHA 2003, p. 6-5). Chronic noncancer health effects include diseases such as reduced lung function and heart disease.

Reference Exposure Levels (RELs)

The analysis for both acute and chronic noncancer health effects compares the maximum project contaminant levels to safe levels known as Reference Exposure Levels, or RELs. These are amounts of toxic substances to which even sensitive individuals could be exposed without suffering any adverse health effects (OEHHA 2003, p. 6-2). These exposure levels are specifically designed to protect the most sensitive individuals in the population, such as infants, the aged, and people with specific illnesses or diseases which make them more sensitive to the effects of toxic substance exposure. The RELs are based on the most sensitive adverse health effect reported in the medical and toxicological literature and include specific margins of safety. The margins of safety account for uncertainties associated with inconclusive scientific and technical information available at the time of the RELs setting. They are therefore meant to provide a reasonable degree of protection against hazards that research has not yet identified.

Concurrent exposure to multiple toxic substances would result in health effects that are equal to, less than, or greater than effects resulting from exposure to the individual chemicals. Only a small fraction of the thousands of potential combinations of chemicals have been tested for the health effects of combined exposures. In conformity with California Air Pollution Control Officers Association (CAPCOA) guidelines, the HRA assumes that the effects of each substance are additive for a given organ system (OEHHA 2003, pp. 1-5, 8-12). Other possible mechanisms due to multiple exposures include those cases where the actions would be synergistic or antagonistic (where the effects are greater or less than the sum, respectively). For these types of exposures, the health risk assessment could underestimate or overestimate the risks.

Cancer Risk and Estimation Process

For carcinogenic substances, the health assessment considers the risk of developing cancer and assumes that continuous exposure to the carcinogen would occur over a 70-year lifetime[4]. The risk that is calculated is not meant to project the actual expected incidence of cancer, but rather a theoretical upper-bound estimate based on the worst-case assumptions.

[4] See footnote 2.

Cancer Potency Factors

Cancer risk is expressed in terms of the number of chances per million of developing cancer. It is a function of the maximum expected pollutant concentration, the probability that a particular pollutant would cause cancer (called a potency factor), and the length of the exposure period. Cancer risks for individual carcinogens are added together to yield a total cancer risk for each potential source. The conservative nature of the screening assumptions used means that the actual cancer risks from project emissions would be considerably lower than estimated.

As previously noted, the screening analysis is performed to assess the worst-case risks to public health associated with the proposed project. If the screening analysis were to predict a risk below significance levels, no further analysis would be necessary and the source would be considered acceptable with regard to carcinogenic effects. If, however, the risk were to be above the significance level, then further analysis using more realistic site-specific assumptions would be performed to obtain a more accurate estimate.

SIGNIFICANCE CRITERIA

Energy Commission staff assesses the maximum cancer impacts from specific carcinogenic exposures by first estimating the potential impacts on the maximally exposed individual. This is a person hypothetically exposed to project emissions at a location where the highest ambient impacts were calculated using the worst-case assumptions. Since the individual’s exposure would produce the maximum impacts possible around the source, staff uses this risk estimate as a marker for acceptability of the project’s carcinogenic impacts.

Acute and Chronic Noncancer Health Risks

As described earlier, non-criteria pollutants are evaluated for short-term (acute) and long-term (chronic) noncancer health effects, and the noted cancer impacts from long-term exposures. The significance of project-related impacts is determined separately for each of the three health effects categories. Staff assesses the noncancer health effects by calculating a hazard index. A hazard index is a ratio obtained by comparing exposure from facility emissions to the safe exposure level (i.e. REL) for that pollutant. A ratio of less than 1.0 suggests that the worst-case exposure would be below the limit for safe levels and would thus be insignificant with regard to health effects. The hazard indices for all toxic substances with the same type of health effect are added together to yield a Total Hazard Index for the source. The Total Hazard Index is calculated separately for acute effects and chronic effects. A Total Hazard Index of less than 1.0 would indicate that cumulative worst-case exposures would be not lead to significant noncancer health effects. In such cases, noncancer health impacts from project emissions would be considered unlikely even for sensitive members of the population. Staff would therefore conclude that there would be no significant noncancer project-related public health impacts. This assessment approach is consistent with risk management guidelines of both California OEHHA and U.S. EPA.

Cancer Risk

Staff relies upon regulations implementing the provisions of Proposition 65, the Safe Drinking Water and Toxic Enforcement Act of 1986, (Health & Safety Code, §§25249.5 et seq.) for guidance in establishing significance levels for carcinogenic exposures. Title 22, California Code of Regulations, section 12703(b) states that “the risk level which represents no significant risk shall be one which is calculated to result in one or less excess cancer cases within an exposed population of 100,000, assuming lifetime exposure.” This risk level is equivalent to a cancer risk of 10 in 1 million, which is also written as 10×10^{-6}. In other words, under state regulations, an incremental cancer risk greater than 10 in 1 million from a project should be regarded as suggesting a potentially significant carcinogenic impact on public health. The 10 in 1 million risk level is also used by the Air Toxics “Hot Spots” (AB 2588) program as the public notification threshold for air toxic emissions from existing sources.

An important distinction between staff’s and the Proposition 65 risk characterization approach is that the Proposition 65 significance level applies separately to each cancer-causing substance, whereas staff determines significance based on the total risk from all the cancer-causing pollutants to which the individual might be exposed in the given case. Thus, the manner in which the significance level applied by staff is more conservative (health-protective) than the manner applied by Proposition 65. The significant risk level of 10 in 1 million is also consistent with the level of significance adopted by many California air districts. In general, these air districts would not approve a project with a cancer risk estimate more than 10 in 1 million.

As noted earlier, the initial risk analysis for a project is typically performed at a screening level, which is designed to overstate actual risks, so that health protection could be ensured. Staff’s analysis also addresses potential impacts on all segments of the population including the young, the elderly, people with existing medical conditions that would render them more sensitive to the adverse effects of toxic air contaminants and any minority or low-income populations that are likely to be disproportionately affected by impacts. To accomplish this goal, staff uses the most current acceptable public health exposure levels (both acute and chronic) set to protect the public from the effects of air toxics being analyzed. When a screening analysis shows the cancer risks to be above the significance level, refined assumptions would be applied for likely a lower, more realistic risk estimate. If, after using refined assumptions, the project’s risk is still found to exceed the significance level of 10 in 1 million, staff would require appropriate measures to reduce the risk to less than significant levels. If, after all feasible risk reduction measures have been considered and a refined analysis still identifies a cancer risk of greater than 10 in 1 million, staff would deem such a risk to be significant and would not recommend project approval.

DIRECT/INDIRECT IMPACTS AND MITIGATION

PROPOSED PROJECT'S CONSTRUCTION/DEMOLITION IMPACTS AND MITIGATION MEASURES

Existing Units 1 through 6 would remain in operation through much of the AEC development and construction. Given that the removal of existing Units 1 through 6 is not required for construction of the AEC, the continued operation of the AGS would not impede AEC construction. Demolition of the retired and decommissioned turbine peaking generating Unit 7 and fuel tank, ancillary equipment, small maintenance shops, and two retention basins would be required for site preparation for the construction of the AEC. Construction and site preparation activities at the AEC site are anticipated to last 56 months, from the first quarter of 2017 to the third quarter of 2021. The project would commence construction with the removal of former Unit 7's building and ancillary equipment, fuel storage tank, tank berms, small maintenance shops and two waste water retention basins in January 2017 to make room for construction and laydown area for the AEC combined-cycle gas turbine block (CCGT). Construction of the AEC CCGT would commence during the second quarter of 2017 and would be completed by the second quarter of 2020. The AEC CCGT is expected to commence commercial operation before May 1, 2020. Construction of the AEC simple-cycle gas turbine block (SCGT) is scheduled to proceed from the second quarter of 2020 through the third quarter of 2021, and is expected to commence commercial operation in the third quarter of 2021 (CH2 2016s, Section 5.9.1). The potential construction/demolition risks are normally associated with exposure to asbestos, fugitive dust, and combustion emissions (i.e. diesel exhaust).

<u>Asbestos</u>

The demolition of buildings containing asbestos would cause the emission of asbestos. Structures built before 1980 are more likely to have asbestos containing materials (ACM). The AEC site buildings were constructed prior to 1980; therefore, asbestos-containing building materials and lead based paint could be present onsite (AEC 2015i, Section 5.14.1.1). Demolition of Alamitos Generating Station Unit 7 could generate approximately 150 tons of asbestos waste (AEC 2015i, Section 5.14.3.2).

Asbestos is a mineral fiber that occurs in rock and soil. Because of its fiber strength and heat resistance, it has been used in a variety of building construction materials for insulation and as a fire-retardant. Asbestos has been used in a wide range of manufactured goods, mostly in building materials (roofing shingles, ceiling and floor tiles, paper products, and asbestos cement products), friction products (automobile clutch, brake, and transmission parts), heat-resistant fabrics, packaging, gaskets, and coatings (US EPA, 2012). Thermal system insulation (formed or spray-on) is the ACM of greatest concern for response and recovery worker exposure (Occupational Safety and Health Administration [OSHA]). Exposure to asbestos and asbestos containing materials (ACM) increases workers' and residents' risk of developing lung diseases, including asbestosis, lung cancer, and mesothelioma.

To reduce the potential risk associated with the removal of asbestos and ACM, the applicant would comply with all requirements outlined in SCAQMD Rule 1403, which requires the notification and special handling of ACM during demolition activities. The applicant would comply with SCAQMD Rule 1403 by:

- Conducting a facility survey to identify and quantify the presence of all friable and non-friable Class I and Class II ACM prior to the start of demolition activities;
- Notifying the SCAQMD and the Energy Commission compliance project manager (CPM) of the intent to conduct demolition activities in a district-approved format (e.g., submittal of a Rule 1403 Plan) prior to the start of any demolition activities;
- Employing one or more of the following methods for asbestos removal: High Efficiency Particulate Air (HEPA) Filtration, Glovebag or Mini-enclosures, Dray Removal, or an alternative approved method;
- Collecting and storing ACM in a leak-tight or wrapped container to avoid releasing ACM to the atmosphere;
- Requiring an onsite representative to complete the Asbestos Abatement Contractor/Supervisor course pursuant to the Asbestos Hazard Emergency Response Act and Provision of Title 40, Code of Federal Regulations, Parts 61.145 to 61.147, 61.152, and Part 763, and be present during all ACM demolition or handling procedures; and
- Disposing of ACM wastes at a licensed waste disposal facility; ACM wastes would be hauled from the site by an appropriately licensed ACM waste transporter.

As a result of the activities listed above and in compliance with SCAQMD Rule 1403, the potential impacts associated with asbestos removal during demolition would be less than significant.

Small quantities of other hazardous wastes could also be generated during construction or demolition phases of the project. The mitigation measures needed to reduce the impacts of asbestos, ACM and other hazardous wastes from the construction or demolition phases of the project are covered in the **Waste Management** section of this FSA. As for asbestos, Conditions of Certification **WASTE-3** requires that the project owner submit the SCAQMD Asbestos Demolition Notification Form to SCAQMD and the Energy Commission CPM for review and approval prior to removal and disposal of asbestos. After receiving approval, the project owner shall remove all ACM from the site prior to demolition. This program ensures there would be no release of asbestos that could impact public health and safety. Please refer to staff's **Waste Management** section for detailed mitigation measures regarding the construction/demolition of asbestos and ACM, and information on the safe handling and disposal of these and all project-related wastes.

Fugitive Dust

Fugitive dust is defined as dust particles that are introduced into the air through certain activities such as soil cultivation, vehicles operating on open fields, or dirt roadways. Fugitive dust emissions during construction and demolition of the proposed project could occur from:

- dust entrained during site preparation and grading/excavation at the construction site;
- dust entrained during onsite movement of construction vehicles on unpaved surfaces;
- wind erosion of areas disturbed during construction activities.

The effects of fugitive dust on public health are covered in the **Air Quality** section of this FSA which includes staff's recommended mitigation measures, including **AQ-SC3** (Construction Fugitive Dust Control) and **AQ-SC4** (Dust Plume Response Requirement) to prevent fugitive dust plumes from leaving the project boundary. As long as the dust plumes are kept from leaving the project site, there would be no significant concern of fugitive dust adversely affecting public health.

Diesel Exhaust

Emissions of combustion byproducts during construction would result from:

- 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, small generators, and compressors;
- exhaust from diesel trucks used to transport workers and deliver concrete, fuel, and construction supplies to construction areas; and
- exhaust from vehicles used by construction workers to commute to and from the project areas.

Construction Health Risk Assessment for Diesel Exhaust

The primary air toxic pollutant of concern from construction/demolition activities is diesel particulate matter (DPM). Diesel exhaust is a complex mixture of thousands of gases and fine particles and contains over 40 substances listed by the U.S. Environmental Protection Agency (EPA) as hazardous air pollutants (HAPs) and by ARB as toxic air contaminants. The DPM is primarily composed of aggregates of spherical carbon particles coated with organic and inorganic substances. Diesel exhaust deserves particular attention mainly because of its ability to induce serious noncancer effects and its status as a likely human carcinogen.

Diesel exhaust is also characterized by ARB as "particulate matter from diesel-fueled engines." The impacts from human exposure would include both short- and long-term health effects. Short-term effects can include increased coughing, labored breathing, chest tightness, wheezing, and eye and nasal irritation. Effects from long-term exposure can include increased coughing, chronic bronchitis, reductions in lung function, and inflammation of the lung. Epidemiological studies strongly suggest a causal relationship between occupational diesel exhaust exposure and lung cancer. Diesel exhaust is listed by the EPA as "likely to be carcinogenic to humans" (U.S. EPA 2003).

Based on a number of health effects studies, ARB's Scientific Review Panel (SRP) on Toxic Air Contaminants in 1998 recommended a chronic REL for diesel exhaust particulate matter of 5 micrograms per cubic meter of air (μg/m^3) and a cancer unit risk factor of 3x10^{-4} (μg/m^3)$^{-1}$. However, SRP did not recommend a specific value for an acute REL since available data in support of a value was deemed insufficient. Therefore, there is no acute relative exposure level (REL) for diesel particulate matter, and it was not possible to conduct an assessment for its acute health effects. In 1998, ARB listed particulate emissions from diesel-fueled engines as a toxic air contaminant and approved the panel's recommendations regarding health effects (OEHHA 2009, Appendix A). In 2000, ARB developed a "Risk Reduction Plan to Reduce Particulate Matter Emissions From Diesel-Fueled Engines and Vehicles" and has been developing regulations to reduce diesel particulate matter emissions since that time.

The total DPM exhaust emissions from construction/demolition activities were averaged over the 56-month construction period and spatially distributed in: (1) the area associated with construction of the AEC CCGT, and (2) the area associated with construction of the AEC SCGT (including the removal of former Unit 7's building and ancillary equipment, fuel storage tank, tank berms, small maintenance shops, and two wastewater retention basins which would occur as site preparation of the AEC CCGT and SCGT) (CH2 2016s, Section 5.9.1.3).

A screening Health Risk Assessment (HRA) for diesel particulate matter was conducted to assess the potential impacts associated with diesel emissions during the construction and demolition activities (i.e. Unit 7) at AEC. The construction HRA estimated the rolling cancer risks during a 30-year exposure duration (starting with exposure during the third trimester) for residential exposure and a 10-year exposure duration (from age 16 to 25) for worker exposure, aligned with the expected construction duration, at the point of maximum impact (PMI), maximally exposed individual resident (MEIR), maximally exposed individual worker (MEIW), and maximum exposed sensitive receptor. The excess cancer risks were estimated using the following (CH2 2016s, Section 5.9.1.3):

- Equations 5.4.1.1 and 8.2.4A from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for residential exposure;
- Equations 5.4.1.2A, 5.4.1.2B, and 8.2.4B from the *Air Toxic Hot Spots Guidance Manual for Preparation of Health Risk Assessments* (OEHHA, 2015) for worker exposure;
- The maximum annual ground-level concentrations used to estimate risk were determined through dispersion modeling with AERMOD;

Based on the applicant's analysis, the maximum modeled annual average concentration of diesel particulate matter was 0.01306 μg/m^3 (CH2 2016s, Appendix 5.9C, Table 5.9C.3 and Table 5.9C.4). The predicted incremental increases in cancer risk at the PMI, MEIR, MEIW, and maximum exposed sensitive receptor associated with construction/demolition activities are 4.9 in one million, 0.89 in one million, 0.16 in one million and 1.19 in one million, respectively. The predicted chronic health index at the PMI, MEIR, MEIW, and maximum exposed sensitive receptor are 0.026, 0.00047, 0.0026, and 0.00064, respectively (CH2 2016s, Section 5.9.1.3). The results are listed in the upper portion of **Public Health Table 2**.

Public Health Table 2
Construction/Demolition Hazard/Risk from DPMs calculated by the Applicant

	Receptor Type	Risk	Significance Level	Significant?
Derived Cancer Risk (per million)	PMI	4.9	10	No
	MEIR	0.89	10	No
	at a Sensitive Receptor	1.19	10	No
	MEIW	0.16	10	No
Chronic HI (dimensionless)	PMI	0.0026	1	No
	MEIR	0.00047	1	No
	MEIW	0.0026	1	No
	at a Sensitive Receptor	0.00064	1	No

Sources: CH2 2016s, Section 5.9.1.3 and Appendix 5.9C (Table 5.9C.3 and Table 5.9C.4)

Based on the results of HRA, and considering two other facts: (1) the potential exposure of DPM would be sporadic and limited in length and (2) the predicted incremental increase in cancer risk at the MEIR and MEIW and chronic health index at the PMI, MEIR, and MEIW are less than the significance thresholds of 10 in one million and 1.0, respectively, staff concludes that impacts associated with the DPM from finite construction activities would be less than significant*.*

Staff also regards the related condition of certification of **AQ-SC5** (Diesel-Fueled Engine Control) in the **Air Quality** section of this FSA as adequate to ensure that cancer-related impacts of diesel exhaust emissions for the public and off-site workers are mitigated during construction/demolition to a point where they are not considered significant.

The chronic hazard indices for diesel exhaust during construction/demolition activities are lower than the significance level of 1.0. This means that there would be no chronic non-cancer impacts from construction/demolition activities.

The potential levels of criteria pollutants from operation of construction-related equipment are discussed in staff's **Air Quality** section along with mitigation measures and related conditions of certification. The pollutants of most concern in this regard are particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO_2), and nitrogen dioxide (NO_2).

PROPOSED PROJECT'S OPERATIONAL IMPACTS AND MITIGATION MEASURES

Emission Sources

As previously noted, the proposed AEC would be a natural gas-fired, combined-cycle and simple-cycle, air-cooled, nominal 1,040-MW, electrical generating facility. Pollutants that could potentially be emitted are listed in **Public Health Table 3,** including both criteria and non-criteria pollutants. These pollutants include certain volatile organic compounds (VOCs) and polycyclic aromatic hydrocarbons (PAHs). Criteria pollutant emissions and impacts are examined in staff's **Air Quality** analysis. Since the facility would use dry cooling, there would be no emissions of toxic metals, particulate matter, or VOCs from cooling tower mist or drift and no health risk from the potential presence of the Legionella bacterium responsible for Legionnaires' disease.

Tables 5.9-1and Table 5.9-2 of the AFC (CH2 2016s) list the specific non-criteria pollutants that would be emitted as combustion byproducts from the AEC natural-gas-fired turbines.

Air toxics emission factors for the CTGs were provided by SCAQMD, with the exception of ammonia (CH2 2016s, Section 5.9.3.1). Emissions from both the combined-cycle and simple-cycle combustion turbines were required by SCAQMD to be revised to be based on US EPS AP-42 emission factors. The 70.8 MMBtu/hr auxiliary boiler was required by the SCAQMD to be revised to be based on the Ventura County Air Pollution Control District (VCAPCD) emission factors for natural gas-fired external combustion equipment rated 10-100 MMBtu/hr (SCAQMD 2016e). The ammonia emission factor was based on an operating exhaust ammonia limit of 5 ppmv at 15 percent oxygen and an F-factor of 8,710 (Note: an F-factor is the ratio of the carbon dioxide generated by the combustion of a given fuel to the amount of heat produced). Additionally, polycyclic aromatic hydrocarbons (PAH) emissions were conservatively assumed to be controlled up to 50 percent through the use of an oxidation catalyst (EPA, 2000), which is proposed for use with both the AEC CCGT and the AEC SCGT (CH2 2016s, Section 5.9.3.1. and Table 5.9-1).

The health risk from exposure to each project-related pollutant is assessed using the "worst case" emission rates and impacts. Maximum hourly emissions are used to calculate acute (one-hour) noncancer health effects, while estimates of maximum emissions on an annual basis are used to calculate cancer and chronic (long-term) noncancer health effects.

Public Health Table 3
The Main Pollutants Emitted from the Proposed Project

Criteria Pollutants	Non-criteria Pollutants
Carbon monoxide (CO)	Acetaldehyde
Oxides of nitrogen (NO_x)	Acrolein
Particulate matter (PM10 and PM2.5)	Ammonia
Oxides of sulfur (SO_2)	Benzene
Volatile Organic Compounds (VOCs)	1,3-Butadiene
	Ethyl Benzene
	Formaldehyde
	Hexane
	Naphthalene
	Polycyclic Aromatic Hydrocarbons (PAHs)
	Propylene Oxide
	Toluene
	Xylene

Source: CH2 2016s, Table 5.9-1 and Table 5.9-2

Hazard Identification

Numerous health effects have been linked to exposure to TACs, including development of asthma, heart disease, Sudden Infant Death Syndrome (SIDS), respiratory infections in children, lung cancer and breast cancer (OEHHA 2003). According to the AEC AFC, the toxic air contaminants emitted from the natural gas-fired CTGs include acetaldehyde, acrolein, ammonia, benzene, 1,3-butadiene, ethyl benzene, formaldehyde, hexane, napthalene, polycyclic aromatics, propylene oxide, toluene and xylene. **Public Health Table 3** and **Public Health Table 4** list each such pollutant.

Public Health Table 4
Types of Health Impacts and Exposure Routes Attributed to Toxic Emissions

Substance	Oral Cancer	Oral Noncancer	Inhalation Cancer	Noncancer (Chronic)	Noncancer (Acute)
Acetaldehyde			✔	✔	✔
Acrolein				✔	✔
Ammonia				✔	✔
Benzene			✔	✔	✔
1,3-Butadiene			✔	✔	
Ethyl Benzene			✔	✔	
Formaldehyde			✔	✔	✔
Hexane				✔	
Napthalene		✔	✔	✔	
Polycyclic Aromatic Hydrocarbons (PAHs)	✔		✔		
Propylene Oxide			✔	✔	✔
Toluene				✔	✔
Xylene				✔	✔

Source: OEHHA / ARB 2016b and CH2 2016s, Table 5.9-1 and Table 5.9-3

Exposure Assessment

Public Health Table 4 shows the exposure routes of TACs and how they would contribute to the total risk obtained from the risk analysis. The applicable exposure pathways for the toxic emissions include inhalation, home grown produce, dermal (through the skin) absorption, soil ingestion, and mother's milk. This method of assessing health effects is consistent with OEHHA's Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA 2015) referred to earlier.

The next step in the assessment process is to estimate the project's incremental concentrations using a screening air dispersion model and assuming conditions that would result in maximum impacts. The applicant used the EPA-recommended air dispersion model, AERMOD, along with 5 years (2006–2009 and 2011) of compatible meteorological data from the North Long Beach meteorological station, which is approximately 6.4 miles to the northwest of the AEC site (AEC 2015i, Section 5.1.6.3 and Appendix 5.1C).

Dose-Response Assessment

Public Health Table 5 lists the toxicity values used to quantify the cancer and noncancer health risks from the project's combustion-related pollutants. It was modified from Table 5.9-3 of the AFC (CH2 2016s), excluding oral cancer potency factor and chronic oral REL. The listed toxicity values include RELs and the cancer potency factors published in the OEHHA's Guidelines (OEHHA 2015) and OEHHA/ARB Consolidation Table of OEHHA/ARB Approved Risk Assessment Health Values (ARB 2016b). RELs are used to calculate short-term and long-term noncancer health effects, while the cancer potency factors are used to calculate the lifetime risk of developing cancer.

Public Health Table 5
Toxicity Values Used to Characterize Health Risks

Toxic Air Contaminant	Inhalation Cancer Potency Factor $(mg/kg\text{-}d)^{-1}$	Chronic Inhalation REL $(\mu g/m^3)$	Acute Inhalation REL $(\mu g/m^3)$
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	60	1,300
1,3-Butadiene	0.60	20	—
Ethyl Benzene	0.0087	2,000	—
Formaldehyde	0.021	9	55 (1-hr) 9 (8-hr)
Hexane	—	7000	—
Napthalene	0.12	9.0	—
Polycyclic Aromatic Hydrocarbons (PAHs)	3.9	—	—
Propylene Oxide	0.013	3	3100
Toluene	—	300	37,000
Xylene	—	700	22,000

Sources: ARB 2016b and CH2 2016s, Table 5.9-3

Characterization of Risks from TACs

As described above, the last step in an HRA is to integrate the health effects and public exposure information, provide quantitative estimates of health risks resulting from project emissions, and then characterize potential health risks by comparing worst-case exposure to safe standards based on known health effects.

The project owner's HRA was prepared using the ARB's Hotspots Analysis and Reporting Program Version 2 (HARP2). Emissions of non-criteria pollutants from the project were analyzed using emission factors, as noted previously, obtained mainly from the SCAQMD. Air dispersion modeling combined the emissions with site-specific terrain and meteorological conditions to analyze the worst-case short-term and long-term concentrations in air for use in the HRA. Ambient concentrations were used in conjunction with cancer unit risk factors and RELs to estimate the cancer and noncancer risks from operations. In the following sub-sections, staff reviews and summarizes the work of the project owner, and evaluates the adequacy of the project owner's analysis by conducting an independent HRA.

Staff evaluated the applicant's analysis, and the results are shown below in **Public Health Table 6**. The analysis was conducted for the general population, sensitive receptors, nearby residences and the project's work force. The sensitive receptors, as previously noted, are subgroups that would be at greater risk from exposure to emitted pollutants, and include the very young, the elderly, and those with existing illnesses.

On March 6, 2015 OEHHA approved a revision to the Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (OEHHA 2015). OEHHA developed age sensitivity factors (ASFs) to take into account the increased sensitivity to carcinogens during early-in-life exposure (OEHHA 2015, Table 8.3). This new methodology is used to reflect the fact that exposure varies among different age groups and exposure occurring in early life has a higher weighting factor.

Health risks potentially associated with ambient concentrations of carcinogenic pollutants were calculated in terms of excess lifetime cancer risks. The total cancer risk at any specific location is found by summing the contributions from the individual carcinogens. Health risks from non-cancer health effects were calculated in terms of hazard index as a ratio of ambient concentration of TACs to RELs for that pollutant.

The following is a summary of the most important elements of the HRA assessment for the AEC:

- the analysis was conducted using the latest version of ARB/OEHHA Hotspots Analysis and Reporting Program Version 2 (HARP2)[5], which incorporates methodology presented in OEHHA's 2015 Guidance;
- emissions are based upon concurrent operation of all two GE 7FA.05 combined-cycle combustion turbines, four GE LMS-100PB simple-cycle combustion turbines, and an auxiliary boiler;

[5] HARP2 can be downloaded from ARB's HARP website. http://www.arb.ca.gov/toxics/harp/harp.htm

- exposure pathways included inhalation, soil ingestion, dermal absorption, home grown produce, and mother’s milk;
- the local meteorological data, local topography, grid, residence and sensitive receptors, source elevations, and site-specific and building-specific input parameters used in the HARP2 model were obtained from the AFC and modeling files provided by the applicant; and
- the emission factors and toxicity values used in staff’s analysis of cancer risk and hazard were obtained from the AFC. The toxicity values are listed in **Public Health Table 5**;

Cancer Risk at the Point of Maximum Impact (PMI)

The most significant result of HRA is the numerical cancer risk for the maximally exposed individual (MEI) which is the individual located at the point of maximum impact (PMI) and risks to the MEI at a residence (MEIR). As previously noted, human health risks associated with emissions from the proposed project are unlikely to be higher at any other location than at the PMI. Therefore, if there is no significant impact associated with concentrations at the PMI location, it can be reasonably assumed that there would not be significant impacts in any other location in the project area. The cancer risk to the MEI at the PMI is referred to as the Maximum Incremental Cancer Risk (MICR). However, 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 maximum residential cancer risk. MICR is based on 24 hours per day, 365 days per year, 30 year lifetime exposure.

As shown below in **Public Health Table 6**, total worst-case individual cancer risk for AEC was 1.44 in one million at the PMI (CH2 2016s, Table 5.9-5). The PMI is located on the east side of project’s boundary. As **Public Health Table 6** shows, the cancer risk value at PMI is below the significance level, 10 in one million, whether the applicant’s or staff’s cancer risk is used, indicating that no significant adverse cancer risk is expected.

Chronic and Acute Hazard Index (HI)

The screening HRA for the project included emissions from all sources and resulted in a maximum chronic Hazard Index (HI) of 0.0036 and a maximum acute HI of 0.019 (CH2 2016s, Table 5.9-5). As **Public Health Table 6** shows, both acute and chronic hazard indices are less than 1.0, indicating that no short- or long-term adverse health effects are expected.

Project-Related Impacts at Area Residences

Staff's specific interest in the risk to the maximally exposed individual in a residential setting is based on the MEIR (MEIR is used for this purpose because this risk most closely represents the maximum project-related lifetime cancer risk). Residential risk is presently assumed by the regulatory agencies to result from an exposure lasting 24 hours per day, 365 days per year, over a 30-year lifetime. Residential risks are presented in terms of MEIR and health hazard index (HHI) at residential receptors in **Public Health Table 6**. The cancer risk for the MEIR, is 1.11, which is below the significance level. The receptor location for the MEIR is approximately 0.33 miles east of the project boundary. The maximum resident chronic HI and acute HI are 0.0028 and 0.018, respectively. They are both less than 1.0, indicating that no short- or long-term adverse health effects are expected at these residences.

Risk to Workers

The cancer risk to potentially exposed workers was presented by the applicant in terms of risk to the maximally exposed individual worker or MEIW at PMI and is also summarized in **Public Health Table 6**. The applicant's assessment for potential workplace risks uses a shorter duration exposure rather than the 30-year exposure used for residential risks. Workplace risk is presently calculated by regulatory agencies using exposures of 8 hours per day, 245 days per year, over a 25- year period. As shown in **Public Health Table 6**, the cancer risk for workers at MEIW (i.e. 0.052 in 1 million) is below the significance level. MEIW is located on the east side of project's boundary. All risks are below the significance level.

Risk to Sensitive Receptors

The highest cancer risk at a sensitive receptor (i.e. Rosie The Riveter Charter High School) is 1.03 in one million, the chronic HI is 0.0026 and the acute HI is 0.017. All risks are below the significance level.

In **Public Health Table 6**, it is notable that the cancer and noncancer risks from AEC operation would be below their respective significance levels. This means that no health impacts would be expected to occur within all segments of the surrounding population. Therefore, staff concludes there is no need for conditions of certification to protect public health.

Title 40 CFR Part 63 Subpart YYYY

The regulation applied to gas turbines located at major sources of HAP emissions is 40CFR Part 63 Subpart YYYY. A major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit.

The total combined formaldehyde emissions from all sources is 5.08 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 11.31 tpy, which is less than 25 tpy. Therefore, the AEC is an area source for HAPS, not a major source. AEC is not subject to this subpart (SCAQMD 2016e).

Public Health Table 6
Cancer Risk and Chronic Hazard from AEC Operations

Receptor Location	Cancer Risk (per million)	Chronic HI[d]	Acute HI[d]
PMI[a]	1.44	0.0036	0.019
Residence MEIR[b]	1.11	0.0028	0.018
Worker MEIW[c]	0.052	0.0036	0.019
Highest Value at Sensitive Receptor	1.03	0.0026	0.017
Significance level	10	1	1
Significant?	No	No	No

Source: CH2 2016s, Table 5.9-5
[a] PMI = Point of Maximum Impact
[b] MEIR = MEI of residential receptors. Location of the residence of the highest risk with a 30-year residential scenario.
[c] MEIW = MEI for offsite workers. Occupational exposure patterns assuming standard work schedule, i.e. exposure of 8 hours/day, 5 days/week, 49 weeks/year for 25 years.
[d] HI = Hazard Index

CUMULATIVE IMPACTS AND MITIGATION

A project would result in a significant adverse cumulative impact if its effects are cumulatively considerable. "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (Cal. Code Regs., tit. 14, § 15130). As for cumulative impacts for cumulative hazards and health risks, if the implementation of the proposed project, as well as the past, present, and probable future projects, would not cumulatively contribute to regional hazards, then it could be considered a less than cumulatively considerable impact.

The geographic scope of analysis for cumulative effects to public health is a six-mile buffer zone around the project site. This is the same six-mile buffer zone for localized significant cumulative air quality impacts described and evaluated in the **Air Quality** section of this FSA. While MATES II and MATES III studies were discussed, cumulative impacts of the proposed project along with other projects within a 6-mile radius were not quantitatively evaluated in the AFC (CH2 2016s, Section 5.9.4).

The maximum cancer risk and non-cancer hazard index (both acute and chronic) for operations emissions from the AEC estimated independently by the applicant, staff, and the SCAQMD (SCAQMD 2016b and SCAQMD 2016e) are all below the level of significance. While air quality cumulative impacts could occur with sources within a 6-mile radius, cumulative public health impacts are usually not significant unless the emitting sources are extremely close to each other, within a few blocks, not miles. Most identified facilities are at least four miles from AEC. Staff, therefore, concludes that the proposed AEC project, even when combined with these projects, would not contribute to cumulative impacts in the area of public health.

The one project located close to AEC would be the potential demolition of AGS. If the demolition of AEC occurs, it would take place during the operations of AEC. While the precise methodology of demolition is unknown, implosion is one possible means which has the potential to emit dust and debris. But there are no dust-generating activities associated with operation of AEC. Therefore, the operation of AEC with the demolition of AGS would not result in cumulative impact to public health. Furthermore, there is no diesel-fueled equipment, only natural gas and natural gas has hardly any particulate matter or hazardous air pollutant emissions. The only concern would be asbestos containing materials (ACM) during demolition of buildings containing asbestos. Again, the operation of AEC with the demolition of AGS would not result in cumulative impact to public health because there are no asbestos-generating activities associated with operation of AEC.

Moreover, as previously noted, the maximum impact location would be the spot where pollutant concentrations for the proposed project would theoretically be highest. Even at this hypothetical location, staff does not expect any significant change in lifetime risk to any person, given the calculated incremental cancer risk of 1.44 in one million, which staff regards as not contributing significantly to the previously noted county-wide population-weighted risks of MATES IV, 415 per million for Los Angeles County and 367 per million for SCAB. Modeled facility-related risks would be much lower for more distant locations. Given the previously noted conservatism in the calculation method used, the actual risks would likely be much smaller. Therefore, staff does not consider the incremental risk estimate from AEC's operation as suggesting a potentially significant contribution to the area's overall or cumulative cancer risk that includes the respective risks from the background pollutants from all existing area sources.

COMPLIANCE WITH LORS

Staff has conducted a HRA for the proposed AEC and found no potentially significant adverse impacts for any receptors, including sensitive receptors. In arriving at this conclusion, staff notes that its analysis complies with all directives and guidelines from the Cal/EPA Office of Environmental Health Hazard Assessment and the California Air Resources Board. Staff's assessment is biased towards protection of public health and takes into account the most sensitive individuals in the population. Using extremely conservative (health-protective) exposure and toxicity assumptions, staff's analysis demonstrates that members of the public potentially exposed to toxic air contaminant emissions of this project, including sensitive receptors such as the elderly, infants, and people with pre-existing medical conditions, would not experience any acute or chronic significant health risk or any significant cancer risk as a result of that exposure.

Staff incorporated every conservative assumption called for by state and federal agencies responsible for establishing methods for analyzing public health impacts. The results of that analysis indicate that there would be no direct or cumulative significant public health impact on any population in the area. Therefore staff concludes that construction and operation of the AEC would comply with all applicable LORS regarding long-term and short-term project impacts in the area of public health.

Additionally, staff reviewed the **Socioeconomics Figure 1**, which shows the environmental justice population (see the **Socioeconomics** and **Executive Summary** sections of this FSA for further discussion of environmental justice) is greater than fifty percent within a six-mile buffer of the proposed AEC site. Because no members of the public potentially exposed to toxic air contaminant emissions of this project would experience acute or chronic significant health risk or cancer risk as a result, there would not be a disproportionate **Public Health** impact resulting from construction and operation of the proposed project to an environmental justice population.

RESPONSE TO PSA COMMENTS

APPLICANT

Comment #1: Page 4.8-10, Cancer Risk and Estimation Process – It is stated “the health assessment considers the risk of developing cancer and assumes that a continuous exposure to the carcinogen would occur over a 70-year lifetime” with a reference to Footnote 4, which points to Footnote 3. Footnote 4 should direct the reader to Footnote 2.

Response: Staff made the edit.

Comment #2: Page 4.8-14, Fugitive Dust – The third bullet indicates that fugitive dust could occur from an onsite concrete batch plant. However, the project is not expected to have an onsite concrete batch plant.

Response: Staff deleted the third bullet.

Comment #3: Page 4.8-19, Public Health Table 3 – Hexane should be included in the Non-criteria Pollutants column of this table as it is emitted from the auxiliary boiler.

Response: Staff added the information of Hexane.

Comment #4: Page 4.8-20, Public Health Table 4 – Hexane should be included in this table as it is emitted from the auxiliary boiler.

Response: Staff added the information of Hexane.

Comment #5: Page 4.8-23, Project-Related Impacts at Area Residences – The maximum resident acute hazard index should be 0.018, consistent with Public Health Table 6.

Response: Staff made the edit.

Comment #6: Page 4.8-23, Risk to Workers – The cancer exposure period for comparison to workers should be revised from 70 years to 30 years, consistent with the revised Office of Environmental Health Hazard Assessment methodology for determining residential risk, as described in Footnote 2 (see PSA page 4.8-9).

Response: Staff made the change and updated the discussion. .

PUBLIC

Comment #7 (City of Seal Beach, TN 212758): The City of Seal Beach is located in close proximity to the Alamitos Energy Center and contains a senior citizen residential development known as Leisure World. This population includes a significant number of seniors with respiratory conditions and sensitive health conditions. The Leisure World population is not specifically identified. This population consists of over 8,000 residents with varying types of health concerns, including sensitive respiratory conditions. The Leisure World community is a very sensitive population that requires consideration during the construction and operation phases.

> **Response:** Staff's analysis does account for the impacts to the most sensitive individuals in the population. In page 4.8-4, the sensitive receptors within a 6-mile radius of the project site were included for health risk assessment (HRA), including 21 nursing homes and 739 hospitals, clinics, and/or pharmacies. Staff also listed some of the nearest sensitive receptors, including the Rosie the Riveter Charter High School, a privately owned and operated school and Kettering Elementary. According to the results of HRA, all risk numbers of these sensitive receptors are below significance thresholds. Therefore, staff concludes that no significant adverse health impacts from toxic air emissions (TACs) are expected at any location of sensitive receptor. For a discussion of other pollutants, please see the **Air Quality** portion of this analysis.

Comment #8 (Dave Shukla, TN 212781): There are real concerns with the public health impacts on nearby neighborhoods in the demolition of current facilities and their replacement with newly constructed alternative systems.

> **Response:** The public health impacts of construction/demolition were discussed in the section of Proposed Project's Construction/Demolition Impacts and Mitigation Measures of this FSA (staring from page 4.8-12). The HRA results were shown in **Public Health Table 2**. According to the results of the HRA, all risk numbers of construction/demolition activities are below significance thresholds. The direct and indirect impacts from the future demolition of existing units 1-6 of the AGS facility are not part of the AEC project and were not quantitatively analyzed. Cumulative impacts were discussed in the cumulative impacts section of this analysis. As noted in this section, operation of the AEC is not expected to contribute to any health impacts from demolition of AGS.

Comment #9 (Ivan Roson, TN 212722): Preliminary Staff Assessment does not include a "Safety" section. Given the new battery technology considered for installation in the improved Alamitos Energy Center, I believe a safety assessment is required to consider issues like: battery explosions, battery fires, battery environmental contamination, etc.

Response: The battery storage facility is not part of the AEC project and is therefore not under Commission review. For a detailed description of the project the Commission is reviewing, see the project description section of the Final Staff Assessment. The city of Long Beach is the jurisdiction that is tasked with permitting the battery facility and performing environmental review under the California Environmental Quality Act. To participate in that process please contact the city of Long Beach.

INTERVENORS

Staff received no comments from the intervenors in the area of Public Health.

AGENCIES

Staff received no comments from the agencies in the area of Public Health.

CONCLUSIONS

Staff has analyzed the potential public health risks associated with construction and operation of the AEC using a highly conservative methodology that accounts for impacts to the most sensitive individuals in a given population. Staff concludes that there would be no significant health impacts from the project's air emissions. According to the results of staff's HRA, both construction/demolition and operating emissions from the AEC would not contribute significantly or cumulatively to morbidity or mortality in any age or ethnic group residing in the project area.

PROPOSED CONDITIONS OF CERTIFICATION

No public health conditions of certification are proposed by staff

ACRONYMS

ACM	Asbestos Containing Materials
AEC	Alamitos Energy Center
AFC	Application for Certification
AGS	Alamitos Generating Station
ARB	California Air Resources Board
ATC	Authority to Construct
Btu	British thermal unit
CAA	Clean Air Act (Federal)
CAL/EPA	California Environmental Protection Agency
CAPCOA	California Air Pollution Control Officers Association
CEC	California Energy Commission (or Energy Commission)
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CTGs	Combustion Turbine Generators
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPM	Compliance Project Manager
DPMs	Diesel Particulate Matter
FSA	Final Staff Assessment (this document)
HAPs	Hazardous Air Pollutants
HARP	Hot Spots Reporting Program
HEPA	High Efficiency Particulate Air
HRA	Health Risk Assessment
HI	Hazard Index
HRSGs	Heat Recovery Steam Generators
Lbs	Pounds
LORS	Laws, Ordinances, Regulations and Standards
MACT	Maximum Achievable Control Technology
MATES	Multiple Air Toxics Exposure Study
MEIR	Maximally Exposed Individual Resident
MEIW	Maximally Exposed Individual Worker
MICR	Maximum Individual Cancer Risk
mg/m^3	Milligrams per Cubic Meter
MMBtu	Million British thermal units
MW	Megawatts (1,000,000 Watts)

NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrates
NOx	Oxides of Nitrogen *or* Nitrogen Oxides
O_2	Oxygen
O_3	Ozone
OEHHA	Office of Environmental Health Hazard Assessment
OSHA	Occupational Safety and Health Administration
PAHs	Polycyclic Aromatic Hydrocarbons
PM	Particulate Matter
PM10	Particulate Matter less than 10 microns in diameter
PM2.5	Particulate Matter less than 2.5 microns in diameter
PMI	Point of Maximum Impact
ppm	Parts Per Million
ppmv	Parts Per Million by Volume
ppmvd	Parts Per Million by Volume, Dry
PSA	Preliminary Staff Assessment
RELs	Reference Exposure Levels
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SIDS	Sudden Infant Death Syndrome
SO_2	Sulfur Dioxide
SO_3	Sulfate
SOx	Oxides of Sulfur
SRP	Scientific Review Panel
TACs	Toxic Air Contaminants
T-BACT	Best Available Control Technology for Toxics
TDS	Total Dissolved Solids
Tpy	Tons per Year
VOCs	Volatile Organic Compounds

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Multiple Air Toxics Exposure Study in the South Coast Air Basin (MATES-III) Final Report, September 2008

Multiple Air Toxics Exposure Study in the South Coast Air Basin (MATES-IV) Final Report, May 2015. http://www.aqmd.gov/home/library/air-quality-data-studies/health-studies/mates-iv

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OEHHA (Office of Environmental Health Hazard Assessment) 2009, Adoption of the Revised Air Toxics Hot Spots Program Technical Support Document for Cancer Potency Factors, 06/01/09. http://oehha.ca.gov/air/hot_spots/tsd052909.html .

OEHHA (Office of Environmental Health Hazard Assessment) 2012, Air Toxics Hot Spots Program Risk Assessment Guidelines. Technical Support Document for Exposure Assessment and Stochastic Analysis, August 2012.

OEHHA (Office of Environmental Health Hazard Assessment). 2015, Air Toxics Hot Spots Program Risk Assessment Guidelines. Guidance Manual for Preparation of Health Risk Assessments, March 6th, 2015.

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SCAQMD 2016e – South Coast Air Quality Management District, Stephen O’Kane (TN 214527). Final Determination of Compliance for Permits to Construct, dated November 18, 2016. Submitted to AES Alamitos, LLC/CEC/Docket Unit on November 18, 2016

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US EPA (Environmental Protection Agency) 2003, http://cfpub.epa.gov/ncea/iris/index.cfm?fuseaction=iris.showQuickView&substance_nmbr=0642 .

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Declarations

&

Resumes

DECLARATION OF
HUEI-AN (ANN) CHU

I, Huei-An (Ann) Chu, declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting, Transmission and Environmental Protection Division as an Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I prepared the staff testimony **on Public Health**, **Transmission Line Safety and Nuisance** for the **Alamitos Energy Center** based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and, if called as a witness, could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 8/17/2016 Signed: Huei-An Chu

At: Sacramento, California

Huei-An (Ann) Chu

1516 Ninth Street, MS-46, Sacramento, CA 95815
Phone: **(916) 651-0965** , Email: Ann.Chu@energy.ca.gov

EDUCATION

PhD, Environmental Sciences and Engineering, 05/2006
School of Public Health, University of North Carolina at Chapel Hill
Area of Specialization: Environmental Risk Assessment, Environmental Management and Policy, Risk-Based Regulation, Biostatistics, Environmental Epidemiology

MEM, Environmental Management, 05/2000
School of Forestry and Environmental Studies, Yale University, New Haven, CT

MS, Environmental Engineering, 06/1998
National Taiwan University, Taipei, Taiwan

BA, Geography, with honors, 06/1996
National Taiwan University, Taipei, Taiwan

SKILLS

Language: Fluent in Chinese and English.

Computer software and programming skills: HARP, SAS, Stata, Minitab, ArcGIS, ArcView, ArcInfo, Stella, Crystal Ball, ISC, ERMapper, Microsoft Excel, PowerPoint, Word.

WORK EXPERIENCE

Air Resources Engineer, California Energy Commission, 1/12/2012 - Present
- Independently performs responsible, varied analyses assessing air quality and public health impacts of energy resource use and large electric power generation projects in California.
- Model air quality and public health impacts of stationary sources using HARP (Hot Spot Analysis and Reporting Program).
- Identify air quality and public health impacts of stationary sources and measures to mitigate these impacts following California Environmental Quality Act and regulations of US EPA (including the National Environmental Policy Act), ARB, and the Districts.
- Collect, analyze, and evaluate data on the effects of air pollutants and power plant emissions on human health, and the environment.
- Ensure conditions of certification are met and recommending enforcement actions for violations.

Research Associate, Taiwan Development Institute, 10/01/2010 – 12/31/2011
- Provided professional consultation for the environmental risk assessment of Taiwan's techno-industrial development initiatives
- Reviewed the environmental risk assessment reports of Taiwan's techno-industrial development initiatives
- Presented in various distinguished lecturer series about environmental risk assessment

Consultant, Chu Consulting, 08/2007 - 07/2010
- Conducted a cumulative risk assessment to evaluate the risk associated with the emissions of VOCs from a petrochemical plants in southern Taiwan
- Used EPA's ISC3 model (based on Gaussian dispersion model) to simulate the dispersion and deposition of VOCs from this petrochemical plant to the neighboring areas, then used ArcGIS to spatially combine the population data and VOC simulation data (and further calculated risks)

- Built a framework of risk-based decision making to set the emission levels of VOCs to reduce people's exposure and the risk of experiencing health problems
- Presented in conference: SRA 2007
- Awarded: CSU-Chico BBS Faculty Travel Funds (2007)

Environmental Justice Intern, Clean Water for North Carolina (CWFNC), Summer, 2005
- Reviewed and critiqued key state environmental policies and the federal EPA Public Participation Policy.
- Interviewed impacted communities, member organizations of the NC Environmental Justice Network, state policy officials about how those policies are actually implemented.
- Wrote a report about the survey and review of environmental justice needs for key state policies.
- Report Publication: "Achieving Environmental Justice in North Carolina Public Participation Policy" (Aug, 2005).

Volunteer, New Haven Recycles and Yale Recycling, 08/1998 – 05/2000
- Promoted recycling and conservation
- Checked trash cans (chosen randomly) and recycling bins at each entryway of residential college, then gave grades.

Volunteer, Urban Resource Initiative (URI), Summer, 1998
- Planted trees for local community of New Haven for a better and sustainable environment

RESEARCH EXPERIENCE

Postdoctoral Research

Department of Public Health Sciences, University of California, Davis, 07/01/2010 - present
Research advisor: Dr. Deborah H. Bennett and Dr. Irva Hertz-Picciotto
- Work on two projects: NIEHS-funded ***Childhood Autism Risks from Genetics and Environment (CHARGE)*** and EPA-funded ***Study of Use of Products and Exposure Related Behavior*** **(*SUPERB)***.
- Perform statistical and quantitative analyses with SAS to analyze collected house dust data and children's urine concentrations of metabolites.
- Conduct exposure assessment to investigate if pesticides, flame retardants, and phthalates are risk factors for children autism.
- Conduct exposure assessment to explore the relationships between children's exposure to phthalate, benzophenone-3 (oxybenzone), triclosan, and parabens, and the use of personal care products.
- Produce scholarly peer-reviewed publications of methodology and findings, and write the final reports of both projects.

Carolina Environmental Program, University of North Carolina at Chapel Hill, 01/01/2006 – 12/31/2006
Research advisor: Dr. Douglas J. Crawford-Brown
- Applied a framework of risk-based decision-making to perchlorate in drinking water. (Awarded: SRA Annual Meeting Travel Award 2006)
- Conducted a material and energy flow analysis (MEFA) to quantify the overall environmental impact of Bank of America operations, and quantitatively analyze the strategies BOA might adopt to reduce these impacts and achieve sustainability. (Report Publication: "Environmental Footprint Assessment")

Doctoral Research, 08/2000-12/2005

Department of Environmental Sciences and Engineering, School of Public Health, University of North Carolina at Chapel Hill
Research advisor: Dr. Douglas J. Crawford-Brown
- Dissertation topic: "**A framework of Risk-Based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Drinking Water as an Example**".
- Conducted risk assessment for arsenic in drinking water.
- Conducted theoretical analysis on the variability and uncertainty issues of risk assessment.

- Conducted a meta-analysis to improve dose-response assessment.
- Conducted analytical and numerical analysis to build a new framework of risk-based decision-making which can be applied coherently across the regulation decisions for different contaminants.
- Presented in conferences: APPAM (2004), SRA (2004, 2005 and 2006), DESE Seminar (2005), CEP Symposium on Safe Drinking Water (2006).
- Awarded: SRA Annual Meeting Student Travel Award (2004 & 2005), UNC-CH Graduate School Travel Grants (2004), UCIS Doctoral Research Travel Awards (2002).

Master's Research

School of Forestry and Environmental Studies, Yale University, 08/1999 - 06/2000
Research advisor: Dr. Xuhui Lee

- Master's project: "**Forest Stand Dynamics and Carbon Cycle**".
- Research project: "Monitoring Forest CO_2 Uptaking"
- Used remote sensing (ERMapper) to investigate the role of forest in the uptake of CO_2.
- Awarded from Teresa Heinz Scholars for Environmental Research Program (2000) and Klemme Award (1999).

Graduate Institute of Environmental Engineering, National Taiwan University, 06/1996 - 06/1998
Research advisor: Dr. Shang-Lien Loh

- Master's thesis: "**The Loads of Air Pollutants from Urban Areas on a Neighboring Dam and its Water Quality**"
- Research Projects: "Research on Air Pollutant Deposition in Urban Areas" and "the Fate and Flow of Recyclable Materials"
- Used Gaussian's Dispersion model (ISC3) to investigate the loads of air pollutants on dam water.

TEACHING EXPERIENCE

Lecturer

Department of Environmental Studies, California State University at Sacramento

- Environmental Politics and Policy, Fall 2011

Department of Geological & Environmental Science, California State University at Chico

- Environmental Risk Assessment, Spring 2009 & 2010
- Applied Ecology, Spring 2008
- Pollution Ecology, Fall, 2007

Department of Geography & Planning, California State University at Chico

- Seminar in Applied Geography & Planning – Environmental Regulation and Policy, Fall, 2007

Department of Forestry and Environmental Resources, North Carolina State University

- Environmental Regulation, Fall, 2006

Teaching Assistant

Department of Environmental Sciences and Engineering, UNC-Chapel Hill

- Environmental Risk Assessment, Spring, 2002
- Introduction to Environmental Science, Fall, 2001
- Analysis and Solution of Environmental Problems, Fall, 2001

Lab Instructor

Department of Environmental Sciences and Engineering, UNC-Chapel Hill

- Biology for Environmental Science, Fall, 2000

Graduate Institute of Environmental Engineering, National Taiwan University

- Water Quality Analysis, Fall, 1997

AWARDS and HONORS

- CSU-Chico BBS Faculty Travel Funds, 2007
- Member of Society of Risk Analysis (SRA), 2006-2008
- SRA Annual Meeting Student Travel Award, 2004-2006
- UNC-CH Graduate School Travel Grants, 2004
- Member of Association for Public Policy Analysis and Management (APPAM), 2004-2005
- UCIS Doctoral Research Travel Awards, 2002
- Graduate Student Teaching and Research Assistantships, 2000-2005
- Teresa Heinz Scholars for Environmental Research Program, 2000
- Yale Forestry & Environmental Studies, Klemme Award, 1999

PUBLICATIONS (SELECTED LIST)

Huei-An Chu*,* Deborah H. Bennett, Irva Hertz-Picciotto, "Phthalates in relation to autism and developmental delay: Exploratory analyses from the CHARGE Study". (In preparation)

Huei-An Chu*,* Deborah H. Bennett, Irva Hertz-Picciotto, "Peronal Care Products: Possible Sources of Children Phthalate Exposure". (In preparation)

Huei-An Chu and Douglas J. Crawford-Brown, "A Probabilistic Risk Assessment Framework to Quantify the Protectiveness of Alternative MCLs for Arsenic in Drinking Water", *Journal of American Water Works Association*. (Being revised)

Huei-An Chu and Douglas J. Crawford-Brown, "Letter to the Editor: Inorganic Arsenic in Drinking Water and Bladder Cancer: A Meta-Analysis in Dose-Response Assessment", *International Journal of Environmental Research and Public Health*, 2007, 4(4), 340-341.

Huei-An Chu and Douglas J. Crawford-Brown, "Inorganic Arsenic in Drinking Water and Bladder Cancer: A Meta-Analysis in Dose-Response Assessment", *International Journal of Environmental Research and Public Health* 2006, 3(4), 316-322.

S.L. Lo and **H.A. Chu**, "Evaluation of Atmospheric Deposition of Nitrogen to the Feitsui Reservoir in Taipei", *Water Science & Technolog*y, 2006, 53(2), 337-344.

CSE Consulting and the UNC Carolina Environmental Program (CEP), "Environmental Footprint Assessment", Report for Bank of America, Aug, 2006.

Huei-An Chu, "Achieving Environmental Justice in North Carolina Public Participation Policy", Report for Clean Water for North Carolina (CWFNC), Aug, 2005.

Huei-An Chu, "Arsenic and its Health Implications", Report for University Center for International Studies Graduate Travel Awards, 2002.

PRESENTATIONS (SELECTED LIST)

Guest Speaker, "Human Health Risk Assessment – Arsenic in Drinking Water as an Example". Tunghai University, Taichuang, Taiwan. (December 16th, 2010)

Guest Speaker, "Environmental Problems in Developing Countries", Course Title: Developing Countries, Department of Economics, CSU-Chico (October 31st, 2008)

"Cumulative Risk Assessment for Volatile Organic Compounds (VOCs) from Petrochemical Plants in Southern Taiwan". Oral Presentation in Society of Risk Analysis (SRA) 2007 Annual Meeting, San Antonio, TX. (December, 2007)

Guest Speaker, "Arsenic in Drinking Water", Course Title: Environmental Geology, CSU-Chico. (November 13th, 2007)

"Risk-Based Environmental Regulation for Arsenic in Drinking Water", Oral Presentation in Department of Environmental Health Seminar, East Tennessee State University (February 2nd, 2007)

"A Framework of Risk-based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Dinking Water as an Example", Oral Presentation in Society of Risk Analysis (SRA) 2006 Annual Meeting, Baltimore. MD. (December, 2006)

"A New Policy Tool to Choose Water Quality Goals under Uncertainty", Poster Presentation in Society of Risk Analysis (SRA) 2006 Annual Meeting, Baltimore. MD. (December, 2006)

"A framework of Risk-Based Decision Making by Characterizing Variability and Uncertainty Probabilistically: Using Arsenic in Drinking Water as an Example", Oral Presentation for National Center for Environmental Assessment (NCEA), Environmental Protection Agency (EAP). (October 26th, 2006)

"Probabilistic Risk Assessment for Arsenic in Drinking Water", Poster Presentation in Carolina Environmental Program (CEP) 2006 Symposium on Safe Drinking Water, Chapel Hill, NC. (March, 2006)

"Probabilistic Risk and Margins of Safety for Water Borne Arsenic", Poster Platform Presentation in Society of Risk Analysis (SRA) 2005 Annual Meeting, Orlando, FL. (December, 2005)

"Using Meta-Analysis in Dose-Response Analysis – Risk Assessment of Arsenic in Drinking Water as an Example", Poster Platform Presentation in Society of Risk Analysis (SRA) 2004 Annual Meeting, Palm Springs, CA. (December, 2004)

DECLARATION OF
Nancy Fletcher

I, **Nancy Fletcher**, declare as follows:

1. I am presently employed by the California Energy Commission in the Engineering Office of the Siting Transmission& Environmental Protection Division as an Air Resources Engineer.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Air Quality/Greenhouse Gas** for the Alamitos Energy Center based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 8, 2016 Signed: Nancy Fletcher

At: Sacramento, California

NANCY L. FLETCHER

nancy.fletcher@energy.ca.gov

PROFESSIONAL EXPERIENCE

CALIFORNIA ENERGY COMMISSION

Air Resources Engineer (02/12-Present): Perform air quality review of new power plant applications and amendments for existing plants, analyze project impacts on air quality including the impacts of greenhouse gases with respect to climate change, perform thermal plume analysis, determine project conformance with applicable federal, state and local laws, ordinances, rules and standards, investigate and recommend appropriate mitigation measures, prepare staff assessments and technical testimony, develop and monitor air quality compliance plans, and develop, recommend and implement planning and policy initiatives for the Energy Commission and the State.

YOLO-SOLANO AIR QUALITY MANAGEMENT DISTRICT

Associate Air Quality Engineer (01/07-01/12): Performed air quality analysis for Authority to Construct, Permit to Operate, Federal Operating Permit, and Emission Reduction Credit applications, reviewed analysis for consistency with local, state and federal regulations, developed and amended local rules and regulations, performed health risk assessments, managed public outreach, conducted public workshops, incorporated state and federal statues into policy, performed inspections for a full range of manufacturing, industrial, commercial and agricultural facilities, supported source testing, and chaired a working group with other local agencies designed to provide a forum for information sharing for consistent engineering analysis and rule development.

Assistant Engineer (08/04-01/06): Developed and amended local rules, drafted a model ordinance, attended local planning meetings to provide technical support, conducted public workshops, performed public outreach, developed standard procedures and policies, performed database QA/QC, reviewed permits and re-evaluated as necessary.

Engineer Technician (02/01-01/02): Prepared reports, updated records, researched and compiled information from files and databases, answered public inquiries and processed public information requests.

BLOCK ENVIRONMENTAL SERVICES

Environmental Engineer (03/00-02/01): Developed Risk Management Programs, performed Phase I site assessments, produced Health and Safety Plans, coordinated multi-agency remediation projects, conducted indoor air quality analysis, completed property investigations, updated the website, and provided support for a local environmental organization.

UNIVERSITY OF CALIFORNIA, BERKELEY

Laboratory Assistant (05/99-03/00): Researched alkali-silica reactions in concrete. Analysis included microscopy and x-ray diffraction.

Engineering Aide (01/00-02/00): Evaluated the denitrification process in wetlands. Laboratory work included ion chromatography.

Teacher's Assistant (08/99-12/99): Prepared course materials, directed labs, led discussions, held office hours, lectured, and graded coursework.

EDUCATION AND CERTIFICATES

UNIVERSITY OF CALIFORNIA, BERKELEY

B.S. Environmental Engineering Science, Geology Minor, May 2000
Approved Cluster: Pollutant Transport and Exposure

Engineer-In-Training, 24 hr HAZWOPER, UC Extension Courses -Introduction to Greenhouse Gas Management, Careers in Public Health, and Aspiring Supervisor Skills, ARB and CAPCOA Trainings.

DECLARATION OF
Dave Vidaver

I, **Dave Vidaver**, declare as follows:

1. I am presently employed by the California Energy Commission in the Electricity Analysis Office.

2. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

3. I helped prepare the staff testimony on **Greenhouse Gas** for the Alamitos Energy Center based on my independent analysis of the Application for Certification and supplements thereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that the prepared testimony is valid and accurate with respect to the issue addressed therein.

5. I am personally familiar with the facts and conclusions related in the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 8, 2016 Signed:__________________________

At: Sacramento, California

Dave Vidaver
Supply Analysis Office
Energy Assessments Division
California Energy Commission
(916) 654-4656
david.vidaver@energy. ca.gov

Employment (all with the California Energy Commission)

Electric Generation System Program Specialist II, Electricity Analysis Office 2011 – present

> Senior analyst responsible for evaluation of procurement, resource adequacy and renewable generation development policies, potential impacts of generation resource development on greenhouse gas emissions.

Electric Generation System Specialist III, Electricity Analysis Office, 2005 - 2011

> Supervisor of Procurement and Resource Adequacy Unit, supervise nine staff responsible for evaluating utility procurement and resource adequacy, combined heat and power and distributed generation issues, role of aging and once-through cooled power plants, compiling and maintaining office databases.

Energy Commission Specialist II, Demand Analysis Office, 2005

> Monitoring near-term load growth at utility and regional level across the WECC; assessing load-temperature relationships for California and major western utilities and long-term changes in temperatures and load-temperature relationships.

Electric Generation System Specialist II, Electricity Analysis Office 2002 – 2005

> Supervisor of Electricity System Modeling Unit; supervised four staff responsible for studies of resource adequacy, market price forecasts, emissions and fuel use studies, assessments of market conditions, role of aging power plants; contributing and principal author of numerous reports, papers, and presentations,

Electric Generation System Specialist I, Electricity Analysis Office, 1998 – 2002

> Simulation modeling of WECC for studies of resource adequacy, market price forecasts, emissions and fuel use studies; assessments of market conditions; contributing and principal author of numerous papers, reports and presentations.

Education

BA, Political Science, University of California, Berkeley
MS, Agricultural Economics, University of California, Davis

Additional Information

Member of the Northwest Power and Conservation Council's Generation Resource Committee, which characterizes the cost and performance of generation technologies for studies undertaken in support of the Council's 5-year power plans; numerous reports at conferences and symposia on topics ranging from natural gas demand in California's electricity sector to implementation of resource adequacy measures in California during 2001- 2004; participant in collaborative proceedings with CPUC (resource adequacy, long-term procurement).