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STATE OF CALIFORNIA – NATURAL RESOURCES AGENCY

EDMUND G. BROWN JR., *Governor*

DATE: February 5, 2016

TO: Interested Parties

FROM: Joseph Douglas, Compliance Project Manager

SUBJECT: MOUTAINVIEW GENERATING STATION PROJECT (00-AFC-02C) Staff Analysis of the Proposed Petition to Amend to replace certain existing combustion turbine components with Advanced Gas Path upgraded components

On January 11, 2016, the Southern California Edison Company (SCE), the owner of the Moutainview Generating Station (Mountainview), filed a petition with the California Energy Commission (Energy Commission) requesting to amend the March 22, 2001 Final Decision for Moutainview. Staff prepared an analysis of this proposed change that can be reviewed on the Energy Commission website (see below).

The 1,056-megawatt project was certified on March 21, 2001, and began commercial operation on January 19, 2006. The facility is located in the City of Redlands, in San Bernardino County.

The modifications proposed in the Petition to Amend (PTA) would change Conditions of Certification to allow SCE to replace certain existing combustion turbine components with Advanced Gas Path upgraded components at the Mountainview Generating Station. These replacement components will improve turbine heat rate, increase generator ramp rate, reduce the generator minimum-load operating point, and increase Mountainview's rated megawatt (MW) output by 48 MW. The Project will continue to meet all existing emissions limits established in the existing permits.

Energy Commission staff reviewed the PTA for conformance with laws, ordinances, regulations and standards (LORS) and assessed the impacts of this proposal on environmental quality and on public health and safety. Staff has recommended language changes to existing Air Quality Conditions of Certification, and a new Traffic and Transportation condition. It is staff's opinion that, with the implementation of the proposed changes, the facility would remain in compliance with applicable LORS and that the proposed modifications would not result in significant adverse direct or cumulative impacts to the environment (Cal. Code of Regs., tit. 20, § 1769). Energy Commission staff intends to recommend the Energy Commission approve the PTA, with staff's proposed changes at the March 4, 2016 Business Meeting.

The Energy Commission's webpage for this facility, http://www.energy.ca.gov/sitingcases/moutainview/, has a link to the petition and the Staff Analysis on the right side of the webpage in the box labeled "Compliance Proceeding." Click on the "Documents for this Proceeding (Docket Log)" option. The

Energy Commission's Order regarding this petition will also be available from the same webpage.

This notice has been mailed to the Energy Commission's list of interested parties and property owners adjacent to the facility site. It has also been e-mailed to the facility listserv. The listserv is an automated Energy Commission e-mail system by which information about this facility is e-mailed to parties who have subscribed. To subscribe, go to the Commission's webpage for this facility, cited above, scroll down the right side of the project's webpage to the box labeled "Subscribe," and provide the requested contact information.

Agencies and members of the public who wish to provide comments on the petition or Staff Analysis must submit their comments by 5:00 p.m. on March 4, 2016. To use the Energy Commission's electronic commenting feature, go to the Energy Commission's webpage for this facility, cited above, click on the "Submit e-Comment" link, and follow the instructions in the on-line form. Be sure to include the facility name in your comments. Once submitted, the Energy Commission Dockets Unit (Dockets Unit) reviews and approves your comments, and you will receive an e-mail with a link to them.

Written comments may also be mailed or hand delivered to:

California Energy Commission
Dockets Unit, MS-4
Docket No. 00-AFC-02C
1516 Ninth Street
Sacramento, CA 95814-5512

All comments and materials filed with the Dockets Unit will become part of the public record of the proceeding.

If you have any questions, please contact Joseph Douglas, Compliance Project Manager, at (916) 653-4677, or by fax to (916) 654-3882, or via e-mail at: joseph.douglas@energy.ca.gov.

If you would like information on participating in the Energy Commission's amendment process, please call the Energy Commission's Public Adviser's Office at (800) 822-6228 (toll-free in California). The Public Adviser's Office can also be contacted via e-mail at publicadviser@energy.ca.gov. News media inquiries should be directed to the Energy Commission Media Office at (916) 654-4989, or by e-mail at mediaoffice@energy.ca.gov.

Enclosure

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MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
EXECUTIVE SUMMARY
Joseph Douglas

INTRODUCTION

On January 11, 2016, the Southern California Edison Company (SCE), the owner of the Moutainview Generating Station (Mountainview), filed a Petition to Amend (PTA or petition) with the California Energy Commission (Energy Commission) requesting to amend the March 22, 2001 Final Decision for Moutainview. Staff prepared an analysis of this proposed change that can be reviewed on the Energy Commission website. The 1,056-megawatt project was certified on March 21, 2001, and began commercial operation on January 19, 2006. The facility is located in the City of Redlands, in San Bernardino County.

The purpose of the Energy Commission's review process is to assess any impacts the proposed modifications would have on environmental quality and on public health and safety. The process includes an evaluation of the consistency of the proposed changes with the Energy Commission's Final Decision (Decision), and if the project, as modified, will remain in compliance with applicable laws, ordinances, regulations, and standards (LORS) (Cal. Code of Regs.,tit. 20 § 1769).

This Staff Analysis (SA) contains the Energy Commission staff's evaluation of the affected technical areas of **Air Quality** and **Traffic** and **Transportation.**

DESCRIPTION OF PROPOSED MODIFICATIONS

These proposed replacement components will improve turbine heat rate, increase generator ramp rate, reduce the generator minimum-load operating point, and increase Mountainview's rated MW output by 48 MW. The Project will continue to meet all existing emissions limits established in the existing permits. The modifications proposed in the PTA would allow SCE to change several **Air Quality** Conditions of Certification to replace certain existing combustion turbine components with Advanced Gas Path upgraded components, and to add a **Traffic and Transportation** Condition of Certification to require the project owner to consult with the FAA to notify pilots using the San Bernardino International Airport and airspace above Mountainview of potential thermal plume air hazards from low-altitude overflight that would result from the proposed changes at the Mountainview Generating Station.

NECESSITY FOR THE PROPOSED MODIFICATIONS

The improved efficiency will be obtained by increasing the turbine firing temperature. The existing hot gas path components such as turbine blades, nozzles, and associated structural elements are not designed to operate at the new, higher temperatures and must be replaced. These components will be functionally identical to the existing equipment except that they will be made from advanced materials that can withstand higher temperatures.

STAFF'S ASSESSMENT OF THE PROPOSED PROJECT CHANGES

The technical areas contained in this Staff Analysis indicate recommended staff changes to the conditions of certification in the Final Decision. Staff believes that by requiring the proposed changes to the existing conditions and an addition of a new condition, the potential impacts of the proposed changes would be reduced to less than significant levels. Staff's conclusions reached in each technical area are summarized in **Executive Summary Table 1**.

Executive Summary Table 1
Summary of Impacts to Each Technical Area

TECHNICAL AREAS REVIEWED	STAFF RESPONSE			New or Modified Conditions of Certification Recommended
	Technical Area Not Affected	No Significant Environmental Impact or LORS noncompliance*	Process As Amendment	
Air Quality			X	X
Biological Resources		X		
Cultural Resources	X			
Efficiency		X		
Facility Design	X			
Geological Resources	X			
Hazardous Materials Management		X		
Land Use		X		
Noise and Vibration	X			
Paleontological Resources	X			
Public Health and Safety	X			
Reliability		X		
Socioeconomics		X		
Soil and Water Resources	X			
Traffic and Transportation			X	X
Transmission Line Safety & Nuisance	X			
Transmission System Engineering	X			
Visual Resources		X		
Waste Management		X		
Worker Safety and Fire Protection		X		

*Staff has concluded that the modifications will not have a significant effect on the environment and the modification will not result in a change or deletion of a condition adopted by the commission in the final decision or make changes that would cause the project not to comply with any applicable laws, ordinances, regulations, or standards (LORS) (Cal. Code Regs., tit. 20, § 1769 (a)(2)).

Energy Commission technical staff reviewed the petition for potential environmental effects and consistency with applicable LORS. Staff has determined that the technical or environmental areas of Cultural Resources, Facility Design, Geological Resources, Noise and Vibration, Paleontological Resources, Public Health and Safety, Soils and Water Resources, Transmission Line Safety and Nuisance, and Transmission System Engineering are not affected by the proposed changes, and no revisions or new conditions of certification are needed to ensure the project remains in compliance with all applicable LORS.

For the technical area **of Biological Resources, Efficiency, Hazardous Materials Management, Land Use, Reliability, Socioeconomics, Visual Resources, Waste Management,** and **Worker Safety and Fire Protection** staff has determined that the modified project would continue to comply with applicable LORS and no changes to any conditions of certification are necessary to ensure impacts remain less than significant.

Staff determined that the technical areas of **Air Quality Resources** and **Traffic and Transportation** would be affected by the proposed project change and has proposed revised and new conditions of certification to assure compliance with LORS and to reduce potential environmental impacts to a less than significant level. The details of the proposed condition changes can be found in the attached **Air Quality** and **Traffic and Transportation Staff Resources Analysis**.

CONCLUSIONS AND RECOMMENDATIONS

Air Quality

The PTA stated that the proposed modification would not require any changes to the Conditions of Certification. However several minor revisions to the Title V permit are being proposed by the South Coast Air Quality Management District (SCAQMD). Minor revisions include updating the equipment descriptions to include the additional capacity from the proposed upgrade, updating the source testing requirements to current standards and format, and reformatting the nitrogen oxide RECLAIM requirements by separating the requirements by equipment type. Staff is proposing to update the **Air Quality** Conditions of Certification where necessary to reflect these changes.

The requested modification would not result in any increases to emission limits. Air quality impacts are considered less than significant. No changes to the project mitigation are being proposed including Emission Reduction Credits (ERCs) or Regional Clean Air Incentives Market (RECLAIM) trade credits. Therefore, there are no **Air Quality** environmental justice issues related to the proposed facility.

Traffic and Transportation

Staff has reviewed the Mountainview PTA which proposes to replace/upgrade certain internal components in the combustion turbine hot gas path. Implementation of existing Conditions of Certification **TRANS-1**, **TRANS-4**, and **TRANS-5** would ensure ground-level traffic impacts are less than significant and the project remains in compliance with applicable laws, ordinances, regulations, and standards. With implementation of staff's proposed new Condition of Certification **TRANS-8** regarding pilot notification and awareness, impacts on aviation safety from potential thermal plume air hazards from low-altitude overflight that would result from the proposed changes would be less than significant.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)

Petition to Amend Commission Decision

AIR QUALITY

Nancy Fletcher

INTRODUCTION

On January 11, 2016, Southern California Edison Company (SCE) filed a Petition to Amend (PTA or petition) with the California Energy Commission (Energy Commission) requesting a modification for the replacement and upgrade of internal components in the gas turbine hot gas path at the Mountainview Generating Station (Mountainview). Mountainview is a nominal 1,056 megawatt (MW) combined cycle electricity generating facility consisting of two generating units, Units 3 and Units 4. Units 3 and 4 each include two 167 gross MW General Electric (GE) 7FA combustion turbines and one 209 MW GE D11 steam turbine. The combustion turbines are equipped with dry low NOx combustors, evaporative air cooling, and heat recovery steam generators. The combustion turbine units exhaust to selective catalytic reduction and oxidation catalysts.

Mountainview is located on a 54.3 acre parcel in the city of Redlands in San Bernardino County in the South Coast Air Basin. The Energy Commission Decision approving Mountainview was adopted on March 21, 2001. Construction of the plant began in September 2001. Construction was suspended, but recommenced in March 2004 and commercial operation began December 2005. The Air Quality Conditions of Certification were amended in July 2001, September 2001, January 2002, September 2004, and July 2006 to include multiple project refinements to equipment, operation, testing and reporting.

The PTA is proposing to replace internal components in the gas turbine hot gas path. SCE plans to replace the combustion turbine components with Advanced Gas Path (AGP) on the four combustion turbines. Many hot gas path components are regularly replaced in turbines according to industry accepted and manufacturer recommended maintenance cycles. SCE is proposing to install the AGP upgraded components as part of the regularly scheduled major maintenance component replacement scheduled for approximately April 2016.

The proposed upgrade to the combustion burners would result in changes to the licensed units. The modification would increase the efficiency of the combustion turbines by improving the heat rate and increasing the generating capacity. The modification would also result in faster ramping rates, reduce the generator minimum-load operating point and extend major maintenance intervals. The project would continue to meet all existing emission limits.

An application was submitted to the South Coast Air Quality Management District (SCAQMD) to renew the SCE, Mountainview Generating Station Title V permit on October 14, 2014. The burner replacement project is being incorporated in the Title V permit renewal process. The SCAQMD Title V analysis has been completed and is undergoing simultaneous 45-day US Environmental Protection Agency (USEPA) regulatory review and SCAQMD 30-day public noticing. The comment and review periods are expected to end in March 2016. SCAQMD draft documents were reviewed by SCE and Energy Commission staff.

The petition stated that the proposed modification would not require any changes to the Conditions of Certification. However, several minor revisions to the Title V permit are being proposed by the SCAQMD. Minor revisions include updating the equipment descriptions to include the additional capacity from the proposed upgrade, updating the source testing requirements to current standards and format, and reformatting (but not increasing) the nitrogen oxide Regional Clean Air Incentives Market (RECLAIM) requirements by separating the requirements by equipment type. Staff is proposing to update the Air Quality Conditions of Certification where necessary to reflect these changes.

Air quality impacts from the proposed changes are considered less than significant including impacts to environmental justice populations. No changes to the project mitigation are being proposed including Emission Reduction Credits (ERCs) or RECLAIM trade credits. 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.

Mountainview is considered a base load facility and is usually operated at more than a 60 percent annual capacity factor. The facility was licensed in 2001 and in operation in 2005 prior to the applicable date of the Greenhouse Gases Emission Performance Standard (Cal. Code Regs, tit. 20, §2900 et seq.). The regulation considers power plants licensed prior to June 30, 2007 as 'deemed–compliant' power plants. The potential capacity increase from the proposal would be below 50 MW. Therefore, the plant would continue to be classified as a 'deemed–compliant' power plant. The Greenhouse Gas (GHG) emissions would still be subject to the California Air Resources Board (ARB) adopted regulations implementing cap-and-trade. 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 would be subject to federal and state mandatory GHG reporting and state cap-and-trade requirements.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS COMPLIANCE

SCAQMD reviewed the requested modifications and determined the changes would comply with their regulations. SCAQMD submitted to staff for review a draft engineering evaluation of the proposed amendments. **Air Quality Table 1** includes a summary of the air quality laws, ordinances, regulations and standards (LORS) applicable to the proposed turbine modification. The requested changes were evaluated by staff for consistency with the following LORS. This is not a comprehensive list of all the LORS the facility is subject to for equipment that would not be impacted by this proposed modification. The conditions of certification in the original Decision and any and all amendments thereafter ensure that the facility would remain in compliance with all LORS.

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

Applicable Law	Description
Federal	**U.S. Environmental Protection Agency (EPA)**
Federal Clean Air Act Amendments of 1990 (FCAAA), Title 40 Code of Federal Regulations (CFR) Part 50	National Ambient Air Quality Standards (NAAQS).
40 CFR 60, Subpart Da	Standards of Performance for Boilers and Duct Burners. Establishes requirements for electric utility steam generators with heat inputs greater than 250 million British thermal units per hour (MMBtu/hr). The duct burners are rated at 135 MMBtu/hr and are not subject to this Subpart.
40 CFR 60, Subpart Db	Standards of Performance for Boilers and Duct Burners. Establishes requirements for electric utility steam generators with heat inputs greater than 100 MMBtu/hr. The duct burners are rated at 135 MMBtu/hr and are subject to this Subpart. Compliance with the 2 parts per million (ppm) best available control technology (BACT) limit demonstrates compliance with the nitrogen oxide (NOx) requirement. Continued compliance is expected.
40 CFR 60, Subpart GG	Standards of Performance for Stationary Combustion Turbines–Requires the turbines to meet emission standards. The applicable limits are 87.9 parts per million for NOx and 150 parts per million for sulfur oxide (SOx). Compliance through source testing has been demonstrated and continued compliance is expected.
40 CFR 60, Subpart KKKK	New Source Performance Standards (NSPS) for Stationary Gas Turbines – Establishes emission standards for turbines installed after February 18' 2005 with heat inputs greater than 10 MMBtu/hr. The turbines were installed prior to 2005 and are therefore not subject to this subpart.
40 CFR 60, Subpart UUUU	Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units –Establishes emission guidelines and approval criteria for State or mulit-State plans that address emission standards limiting greenhouse gas (GHG) emissions from an affected units. The state plan has not been approved and therefore there are no currently applicable requirements. The facility will be required to comply with the plan when applicable.
40 CFR 63, Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Gas Turbines. This subpart establishes requirements for facilities that are major sources of hazardous air pollutants (HAPS). The facility is not considered a major source of HAPS since HAP emissions are less than the 25 ton/year threshold.
40 CFR 64	Compliance Assurance Monitoring (CAM)–CAM regulations apply to major stationary sources that use control equipment to achieve emission limits. The turbines are major sources for NOx, carbon monoxide (CO) and volatile organic compound (VOC) emissions. NOx and CO meet applicable BACT limits by using external control equipment consisting of selective catalytic reduction (SCR) and oxidation catalysts. VOCs are not subject since emissions are controlled by efficient combustor design and the use of natural gas and not external controls. Compliance is demonstrated by CEMS. Continued compliance with this rule is expected.

Applicable Law	Description
40 CFR 72	Permits Regulation -Part 72 establishes the Acid Rain Permit Program. The acid rain program requirements establish controls for sulfur dioxide (SO_2) and NOx emissions from fossil fuel-fired combustion used to generate electricity. Facilities are required to cover SO_2 emissions with allowances or offsets. Mountainview is subject to the acid rain program. The facility would continue to comply with SO_2 emissions monitoring by using the gas meter in conjunction with natural gas composition analysis.
State	**California Air Resources Board and Energy Commission**
California Health & Safety Code §41700 (Nuisance Regulation)	Prohibits discharge of such quantities of air contaminants that cause injury, detriment, nuisance, or annoyance.
California Health & Safety Code 40910-40930	Permitting of source needs to be consistent with approved clean air plan.
California Code of Regulations	Greenhouse Gases Emission Performance Standard (EPS), Article 1 –Provisions Applicable to Power Plants 10 MW and Larger (SB1368) —The facility is considered a deemed-compliant powerplant.
Local	**South Coast Air Quality Management District (SCAQMD)**
Regulation II Permits Rule 212	Standards for Approving Permits and Issuing Public Notice—Outlines specific criteria for approving permits and issuing public notice. Outlines requirements for Regional Clean Air Incentives Market (RECLAIM) facilities. Mountainview is not located within 1,000 feet of a school and the proposed changes will not result in an increase in emissions of toxic contaminants that would expose a person to levels above noticing thresholds.
Regulation II Permits Rule 218	Continuous Emission Monitoring (CEM)—Establishes requirements for CEMS. Only the CO CEMS is subject to Rule 218 requirements. Each turbine is already operating with compliant CEMS. Retention of record and reporting requirements are followed. Continued compliance is expected.
Regulation IV Prohibitions Rule 401	Visible Emissions—Establishes limits on visible emissions. Visible emissions are not expected from Mountainview. SCAQMD reported there is no indication of visible emission problems in their compliance database.
Regulation IV Prohibitions Rule 402	Nuisance—Prohibits the discharge of air contaminants or other material which could detrimentally impact the public. Mountainview uses ammonia for the SCR. The facility maintains a 5 ppm ammonia slip level. Nuisance problems are not expected from Mountainview under normal operations.
Regulation IV Prohibitions Rule 407	Liquid and Gaseous Air Contaminants—Establishes a CO emission limit of 2,000 parts per million by volume (ppmv) from the turbines. The CO emissions from the turbines are subject to a more stringent CO emission limit of 6 ppmvd (ppmv dry) at 15 percent oxygen (% O_2), meeting this regulation.
Regulation IV Prohibitions Rule 409	Combustion Contaminants—Establishes restrictions on particulate matter emissions from the turbines to 0.1 grain per cubic foot at 12% O_2. Source testing data indicates compliance below the rule limit.
Regulation IV Prohibitions Rule 431.1	Sulfur Content of Gaseous Fuels—Limits the sulfur concentration to 16 ppmv (calculated as hydrogen sulfide) in natural gas. Continued compliance is expected because commercial grade natural gas has an average sulfur content of 4 ppm.
Regulation IV Prohibitions Rule 475	Electric Power generating Equipment—Limits combustion contaminants to 11 lbs/hr or 0.01 grains per standard cubic feet (gr/scf) for power generating equipment greater than 10 MW. Continued compliance is expected.

Applicable Law	Description
Regulation XIII New Source Review	New Source Review for Criteria Pollutants—This regulation applies to new or modified sources that have increased emissions. The burner upgrade project replaces the burner with a more efficient burner. There will be no increase in the heat input rate and the emission limits will remain unchanged.
Regulation XIII New Source Review Rule 1325	Federal PM2.5 New Source Review Program—Outlines requirements for particulate matter less than 2.5 microns (PM2.5) for any new major polluting facility or major modification to a major polluting facility located in areas designated as non-attainment for PM2.5. The burner upgrade is not considered a major modification.
Regulation XIV Toxics and Other Non-Criteria Pollutants Rule 1401	New Source Review of Toxic Air Contaminants (TAC)—Specifies limits for maximum individual cancer risk and acute and chronic hazard index for modifications to existing facilities emitting toxic air contaminants. The proposed project has no emission increases and therefore does not have any associated increase in risk and is considered exempt from the rule requirements.
Regulation XVII Prevention of Significant Deterioration (PSD)	Prevention of Significant Deterioration–Establishes requirements for attainment emissions. The south coast air basin (SCAB) is in attainment for nitrogen dioxide (NO_2), SO_2, CO and particulate matter less than ten microns (PM10) national ambient air quality standards. SCAQMD has partial delegation of PSD authority from the EPA depending on the calculation methodology and plant wide applicability limits. SCE calculations conclude the project does not trigger a PSD review. See discussion in analysis.
Regulation XVII Prevention of Significant Deterioration (PSD) Rule 1714	Prevention of Significant Deterioration (PSD) for Greenhouse Gases (GHGs)— For consistency with the Supreme Court's decision, the SCAQMD will not be issuing a PSD permit for greenhouse gases for this project. See discussion in analysis.
Regulation XX Regional Clean Air Incentives Market (RECLAIM) Rule 2005	New Source Review for RECLAIM—Establishes requirements for new or modified facilities subject to the RECLAIM program. BACT is required for a modified source resulting in specified emission increases. The turbines already meet BACT requirements. The required modeling is combined with the Rule 1303(b)(1) modeling analysis. RECLAIM trading credits (RTCs) will be required for the turbines and black start engine. RTCs will be obtained from the appropriate trading zone. The applicant is in compliance with all applicable federal emission limitations or standards. Public notice requirements will be combined with other noticing requirements.
Regulation XXX Title V Permits Rule 3003	Applications—Establishes application procedures for facilities subject to Title V requirements. The SCAQMD determined that the requested amendment is considered a significant permit revision and requires a 45-day EPA review and 30-day public notice period. The SCAQMD submitted the revised CPP Title V permit to EPA for review on January 26, 2016 and the review period should conclude in March 2016.

SETTING

Federal and state ambient air quality attainment status designations have changed since the Energy Commission Decision. Mountainview is located in the city of Redlands, San Bernardino County, and is part of the South Coast Air Basin. For convenience, staff includes **Air Quality Table 2**, which summarizes the area's attainment status for current state and federal ambient air quality standards (AAQS) for the South Coast Air Basin. The air quality standards are health-based standards established by the EPA and Air Resources Board (ARB), and are set at levels to protect the health of all members of the public including those most sensitive to adverse air quality impacts such as the elderly, people with existing illnesses, children, and infants.

Air Quality Table 2
SCAQMD Attainment Status

Pollutants	Attainment Status	
	Federal Classification	**State Classification**
Ozone (1-hr)	No Federal Standard	**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**

Note: Unclassified means the area is treated as if it is in attainment.
Note: January 2016

ANALYSIS

SCE is proposing to upgrade Mountainview’s four combustion turbines to AGP and Dry Low NOx Combustion (DLN 2.6+) technologies. AGP technology improves efficiency through increasing the turbine firing temperature. The existing turbine blades, nozzles and associated structures are not designed to withstand higher firing temperature and would therefore need to be replaced. The replacement components are considered to be functionally equivalent.

Mountainview currently uses DLN 2.6 technology. The DLN 2.6+ technology uses a swozzle (a nozzle that imparts swirl) to provide a better mix and more stable combustion zone. The result is maintaining low emission rates over an extended available operation load range. The advanced material for the DLN 2.6+ also extends the combustors maintenance intervals.

The Mountainview Air Quality Conditions of Certification contain a detailed description of the energy generating components. The descriptions include operational parameters such as heat rates and generating capacities and form the basis of the environmental analysis. These equipment descriptions are enforceable parts of the license and must be updated if the equipment or operation of the equipment changes outside the parameters included in the descriptions.

The equipment descriptions also include identifiers that link the units to emission and reporting requirements and provide a road map to the licensed equipment configuration. The identification numbers assigned to the emission units originally lined up with the SCAQMD permits. Over time, changes have been made to the permit formats and some of the identification numbers in the equipment descriptions are no longer valid. In addition separate equipment components are now grouped together as one identifier when equipment is interconnected to perform one function. In order to provide a more accurate accounting of the equipment and requirements, staff is proposing to update the identifiers and process descriptions to once again line up with the SCAQMD permits.

Mountainview consists of four combustion gas generators and two steam turbine generators. Two combustion turbines are paired with one steam turbine to form two combined cycle units, Unit 3 and Unit 4. Each combustion turbine exhausts into a heat recovery steam generator (HRSG), equipped with an oxidation catalyst for the removal of CO and a selective catalytic convertor for the removal of NOx. Each HRSG also has duct firing capabilities to increase the steam production during peak loads. The steam produced in each HRSG is sent to a single steam turbine. For consistency with SCAQMD permitting convention, staff is proposing the same ID number assignment to the combustion turbine with generator, the HRSG and steam turbine. Since the steam turbine is connected with two separate combustion generators and HRSGs, the steam turbines would be listed with each equipment cluster it is linked with. Therefore, the same steam turbine is listed with two separate ID numbers, each unique to the generating unit as a whole. These updates to the identification numbers assigned to the equipment and the descriptions are to clarify this process and provide essential details regarding the control equipment and specify the stacks the equipment is connected to.

The PTA states the proposed modification would not impact the project's ability to comply with applicable LORS. The amendment notes that due to the project upgrades the project would become subject to Subpart KKKK. Subpart KKKK apples to stationary combustion turbines with heat inputs at peak load equal or greater than 10 MMBtu/hr that commenced construction, modification or reconstruction after February 18, 2005. Mountainview was licensed in 2001 and commenced commercial operation in 2005. CFR part 60 defines modification as a physical change or change in operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility. Subparts GG and KKKK both only regulate NOx and SO_2. The upgrade does not result in an increase in emission of NOx or SO_2. In addition, the project was amended in 2006 resulting in an increase in the VOC emission limit from the combustion turbine. The definition specifies 'to which a standard applies' and the subpart does not include standards for VOCs. Therefore, the change to the VOC limit would not trigger the definition of a modification under Part 60 or trigger Subpart KKKK requirements. Subpart GG would continue to apply to the combustion turbines. The project is expected to continue to meet Subpart GG requirements. In addition, the applicant states the plant already complies with the more stringent requirements in Subpart KKKK and would continue to do so after the upgrade.

The proposed upgrade does not trigger SCAQMD New Source Review (NSR) for criteria pollutants. The regulation only applies to modifications that result in increased emissions. The emissions limits will therefore remain unchanged. The equipment is subject to source test requirements that will verify the project will continue to operate within the permitted parameters. Air Quality Condition of Certification **AQ-15** requires the facility to annually source test for NOx, CO, and NH_3 and triennially for SOx, VOC, and PM10. Mountainview is scheduled to conduct the next triennial test in the first quarter of 2017. In addition NOx and CO limits are continuously monitored through the CEMS. Staff agrees with the SCAQMD assessment that a separate source test is not necessary for compliance verification after the proposed upgrade.

AQ-36 includes the SCAQMD NOx RECLAIM requirements for the facility. Mountainview mitigates the NOx emission for the facility through the RECALIM program by holding RECLAIM Trading Credits (RTCs) for the facility's NOx emission units. The SCAQMD is proposing changes to the format of the conditions outlining the RTC requirements. The SCAQMD is not proposing any changes to the total amount of RTCs required but is separating the required allotment of RTCs to be held by the facility for the duct burners from the combustion turbine requirements. This would allow the facility to operate the combustion turbines regardless of if the facility holds RTCs for duct burning since the combustion turbines can be operated independently from the duct burners. The Title V permit conditions have a separate condition for each of the pieces of equipment subject to the regulation. The draft Title V permit has a total of ten RECLAIM conditions, four conditions for the combustion turbines, four conditions for the duct burners, one condition for the emergency fire pump and one condition for the emergency engine. Staff is proposing to break up the RTC requirements for **AQ-36** into separate requirements for each emission unit subject to the requirements to provide flexibility of operation to the facility owner. In addition, **AQ-36** has outdated language and an outdated RTC holding requirement. Staff is proposing to update **AQ-36** to incorporate the updating format, description and requirements.

The SCAQMD has partial delegation of PSD authority from the USEPA. An applicant can apply directly to the SCAQMD for a PSD permit so long as the applicant does not use additional calculation methodologies and the permit is not based on a 'Plantwide Applicability Limit'. SCE opted to seek PSD approval directly from the USEPA due to the use of additional calculation methodologies promulgated in 40 CFR 52.21. SCE submitted an applicability analysis to the USEPA on December 18, 2015. SCE calculations conclude the modification would not result in any significant emission increases and therefore would not trigger PSD review for criteria pollutants or greenhouse gas. SCE is not required to obtain a PSD determination from USEPA prior to the scheduled upgrade.

The SCE applicability analysis uses methodologies outlined in 40 CFR 52.21. The SCE applicability analysis includes baseline emission calculations, projected actual emissions calculations, and unused capacity emission calculations. The applicability analysis compares the projected emissions to baseline emission to determine if there were increases over the significant thresholds. The baseline emissions are the annual average emissions from 2013 and 2014. The projected emissions are based on projected business activity for the 2018 calendar year. Based on forecasts, 2018 is when maximum annual emissions are expected to occur. The emission increase for CO, SO_2 and NO_2 were below the significance threshold based on just the comparison between the baseline and projected emissions. The regulations allow for unused capacity to be factored into the comparison. The emission increase for PM10 and GHG based on a straight comparison exceeded the threshold criteria. SCE factored in the unused capacity into the emission comparison which resulted in a decrease for all pollutants including PM10 and GHG. The results indicated the upgrade would not be considered a major modification and a PSD review would not be required. EPA has reviewed and accepted the determination.

SCE included GHGs in the applicability analysis although a GHG PSD would not be required if a PSD review is not required for any other criteria pollutant. In May 2010, USEPA issued the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule establishing thresholds for GHG emissions. The regulation includes criteria for two phase-in steps with a commitment to develop a third step if necessary. Step 1 affected existing facilities that were already subject to PSD requirements and modifications that increased CO2e emissions over 75,000 tons per year. Step 2 affected new facilities with proposed CO2e emissions over 100,000 tons per year and modifications at existing facilities with increases in CO2e emissions over 75,000 tons per year. However, on June, 23, 2014, the U.S. Supreme Court issued a decision regarding the application of stationary source permitting requirements to GHGs. The decision determined that GHGs could not be considered as an air pollutant for determining if a source is a major source requiring a PSD or Title V permit. The decision clarified that PSD permits could still be required based on emissions of conventional pollutants and GHG emissions could be limited in these circumstances based on the application of BACT. The proposed project upgrade does not trigger a PSD review for criteria pollutants. Therefore, the project does not trigger a GHG PSD review.

SB 1368,[1] 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[2] (MWh)(1,100 pounds CO_2/MWh). If a project, instate or out of state, plans to sell base load electricity 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 higher than 60 percent. Compliance with the EPS is determined by dividing the annual average carbon dioxide emissions by the annual average net electricity production in MWh. Mountainview is considered a base load facility and can be operated at more than 60 percent capacity factor annually. The facility was licensed in 2001 and commenced operation to 2005 prior to the applicability date for the Greenhouse Gases Emission Performance Standard (Cal. Code Regs., tit. 20, §2900 et seq.). The regulation considers power plants licensed prior to June 30, 2007 as ‘deemed–compliant’ power plants. The potential capacity increase from the proposal would be below 50 MW therefore the plant would continue to be classified as a ‘deemed–compliant’ power plant.

[1] Public Utilities Code § 8340 et seq.

[2] The Emission Performance Standard only applies to carbon dioxide and does not include emissions of other greenhouse gases converted to carbon dioxide equivalent.

Staff is also proposing a small correction to the emergency internal combustion (IC) engine description. The description was modified through an insignificant project change on January 4, 2006. On June 29, 2006 an Energy Commission order approved modifications to the Air Quality Conditions of Certification including the engine description. Some of the applicable changes from the January order were not carried through. Staff is proposing to make the necessary correction to the equipment description.

CONCLUSIONS AND RECOMMENDATIONS

Energy Commission staff recommends approval of the requested changes to the Air Quality Conditions of Certification for Mountainview. Specifically, Energy Commission staff recommends updating the equipment description to reflect the changes from the proposed hot gas path upgrade. Staff is also proposing an administrative update to the emergency engine description. In addition staff is proposing to update and restructure of **AQ-36** in order to clearly identify Mountainview's RECLAIM requirements. These requested changes are considered administrative in nature and will conform with the applicable LORS related to air quality and will not result in significant air quality impacts. The requested changes have already been analyzed by SCAQMD staff and a draft Title V permit incorporating the upgrade is currently in public notice.

PROPOSED AND AMENDED CONDITIONS OF CERTIFICATION

Staff recommends the following modifications to the Air Quality Conditions of Certification. **Bold underline** is used to indicate new language. ~~Strikethrough~~ is used to indicate deleted language. For convenience, a clean version of all the conditions reflecting the proposed changes that would become applicable to Mountainview follows the strikeout underline text in Appendix A.

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

1,991 MMBTU/HR **at 30 degrees Fahrenheit** **natural** Gas Turbine ~~(ID No. D18) (A/N 391557)~~ No. 3~~-1~~**A** GE Model 7FA.**04** with Dry Low NOx combustors **DLN 2.6+** connected directly to a ~~175.7~~ **177.1 MW** (~~nominal at ISO conditions~~ **gross output at 59 degrees Fahrenheit**) Electric Generator ~~(ID No. B19)~~ and a Heat Recovery Steam Generator ~~(ID No. B20)~~ with 135 MMBTU/HR Duct Burners ~~(ID No. D21)~~ connected **to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3B).** ~~in common with Gas Turbine No. 3-2 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B22).~~ **Turbine 3A, the HRSG, and steam turbine are all identified as ID No. D18 (A/N 500208) and the duct burners are identified as ID No. D21 (A/N 578178). Equipment D18 and D21 are both connected to a CO oxidation catalyst, No. 3-1 (ID No. C23) (A/N 562528), with 240 cubic feet of total catalyst volume,** Selective Catalytic Reduction**, No. 3-2** (ID No. C24) (A/N ~~366151~~**562528**)**,** with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.~~6~~**5** feet wide with an ammonia injection grid ~~(ID No. B25)~~**,** and **share a common stack, Stack No. 3A (ID No. S26), with a height of 200 feet and diameter of 18 feet.** ~~a CO oxidation catalyst (ID No. C23) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S26) (A/N 391557) No 3-1/3-2.~~

1,991 MMBTU/HR **at 30 degrees Fahrenheit** **natural** Gas Turbine ~~(ID No. D27) (A/N 391558)~~ No. 3~~-2~~**B** GE Model 7FA.**04** with Dry Low NOx combustors **DLN 2.6+** connected directly to a ~~175.7~~ **177.1 MW** (~~nominal at ISO conditions~~ **gross output at 59 degrees Fahrenheit**) Electric Generator ~~(ID No. B28)~~ and a Heat Recovery Steam Generator ~~(ID No. B29)~~ with 135 MMBTU/HR Duct Burners ~~(ID No. D30)~~ connected **to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3A).** ~~in common with Gas Turbine No. 3-1 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B31).~~ **Turbine 3B, the HRSG, and steam turbine are all identified as ID No. D27 (A/N 578179) and the duct burners are identified as ID No. D30 (A/N 578179). Equipment D27 and D30 are both connected to a CO oxidation catalyst, No. 3-2 (ID No. C32) (A/N 562529), with 240 cubic feet of total catalyst volume,** Selective Catalytic Reduction**,** No. 3-2 (ID No. C33) (A/N ~~366152~~**562529**)**,** with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.~~6~~**5** feet wide with an ammonia injection grid ~~(ID No. B34)~~**,** and **share a common stack, Stack No. 3B (ID No. S35), with a height of 200 feet and diameter of 18 feet.** ~~a CO oxidation catalyst (ID No. C32) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S35) (A/N 391559) No 3-1/3-2.~~

1,991 MMBTU/HR **at 30 degrees Fahrenheit** **natural** Gas Turbine ~~(ID No. D36) (A/N 391559)~~ No. 4~~-3~~**A** GE Model 7FA.**04** with Dry Low NOx combustors **DLN 2.6+** connected directly to a ~~175.7~~ **177.1 MW** (~~nominal at ISO conditions~~ **gross output at 59 degrees Fahrenheit**) Electric Generator ~~(ID No. B37)~~ and a Heat Recovery Steam Generator ~~(ID No. B38)~~ with 135 MMBTU/HR Duct Burners ~~(ID No. D39)~~ connected **to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 4B).** ~~in common with Gas Turbine No. 4-4 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B40).~~ **Turbine 4A, the HRSG, and steam turbine are all identified as ID No. D36 (A/N 578180) and the duct burners are identified as ID No. D39 (A/N 578180). Equipment D36 and D39 are both connected to a CO oxidation catalyst, No. 4-1 (ID No. C41) (A/N 562530), with 240 cubic feet of total catalyst volume,** Selective Catalytic Reduction**, No. 4-1** (ID No. C42) (A/N ~~366153~~**562530**)**,** with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.~~6~~**5** feet wide with an ammonia injection grid ~~(ID No. B43)~~**,** and **share a common stack, Stack No. 4A (ID No. S44), with a height of 200 feet and diameter of 18 feet.** ~~a CO oxidation catalyst (ID No. C41) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S44) (A/N 391559) No 4-3/4-4.~~

1,991 MMBTU/HR **at 30 degrees Fahrenheit** **natural** Gas Turbine ~~(ID No. D45) (A/N 391560)~~ No. 4~~-4~~**B** GE Model 7FA.**04** with Dry Low NOx combustors **DLN 2.6+** connected directly to a ~~175.7~~ **177.1 MW** (~~nominal at ISO conditions~~ **gross output at 59 degrees Fahrenheit**) Electric Generator ~~(ID No. B46)~~ and a Heat Recovery Steam Generator ~~(ID No. B47)~~ with 135 MMBTU/HR Duct Burners ~~(ID No. D48)~~ connected **to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3B).** ~~in common with Gas Turbine No. 4-3 to a 214.5 MW (nominal at ISO conditions) steam turbine (ID No. B49).~~ **Turbine 3A, the HRSG, and steam turbine are all identified as ID No. D45 (A/N 578181) and the duct burners are identified as ID No. D48 (A/N 578181). Equipment D45 and D48 are both connected to a CO oxidation catalyst, No. 4-2 (ID No. C50)(A/N 562531), with 240 cubic feet of total catalyst volume,** Selective Catalytic Reduction, **No. 4-2** (ID No. C51) (A/N ~~366154~~**562531**) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.~~6~~**5** feet wide with an ammonia injection ~~grid (ID No. B52)~~**,** and **share a**

common stack, Stack No. 4B (ID No. S53), with a height of 200 feet and diameter of 18 feet. ~~a CO oxidation catalyst (ID No. C50) with 240 cubic feet of total volume connected to an exhaust stack (ID No. S53) (A/N 391560) No 4-3/4-4.~~

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

Internal combustion engine, emergency power, diesel Caterpillar 3512B~~-LE2200,~~ turbocharged, aftercooled, ~~2,200~~**2,155** BHP A/N ~~366155~~**500222** (ID. No. D~~54~~**61**)

The following Condition of Certification pertains to the gas turbines, duct burners and emergency engines

AQ-36 **The following condition is applicable to each of the four combustion turbines (D19, D27, D36, D45):**

A. The gas turbine~~s~~ shall not be operated unless the ~~operator~~ **facility** ~~demonstrates to the District and CPM that the facility~~ holds ~~sufficient~~ **114,412 pounds of NOx** RTCs **in its allocation account** to offset the ~~prorated~~ annual emissions increase for the first compliance year of operation. **The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation.** In addition, the gas turbine~~s~~ shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds ~~sufficient~~ **107,552 pounds of** NOx RTCs ~~in an amount equal to the annual emission increase~~ **valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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**.

~~The owner/operator shall limit the first year, defined as the first 12 months following initial operation, cumulative facility wide NOx emissions from all equipment to no more than 492,897 lbs/year.~~

~~The owner/operator shall prior to the beginning of all years subsequent to the first year (as defined above), hold a minimum of 464,338 lbs of NOx RTCs for the operation of all equipment at the facility.~~

~~In accordance with District Rule 2005 (f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first compliance year.~~

The following condition is applicable to each of the four duct burners (D21, D30, D39, D48):

B. The duct burner shall not be operated unless the facility holds 7,758 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the duct burner shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 7,293 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

The following condition is applicable to the emergency fire pump engine (D58):

C. The emergency fire pump IC engine shall not be operated unless the facility holds 841 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the emergency fire pump IC engine shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 841 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

The following condition is applicable to the emergency IC engine (D61):

D. The emergency IC engine shall not be operated unless the facility holds 1,549 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the emergency IC engine shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first

compliance year of operation, the facility holds 1,549 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

Verification: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District in each Quarterly Operational Report. (see **AQ-8**).

APPENDIX A

CONDITIONS OF CERTIFICATION INCLUDING PROPOSED CHANGES

AQ-C1 The project owner shall require as a condition of its construction contracts that all contractors/subcontractors ensure that all heavy earthmoving equipment, that includes, but is not limited to bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer's specifications. The project owner shall further require as a condition of its construction contracts that this equipment shall either (1) employ high pressure fuel injection; (2) employ injection timing retardation to control the emissions of oxides of nitrogen; or (3) be certified to EPA off-road equipment emission standards. The project owner shall further require as a condition of its construction contracts that all diesel fired construction equipment use CARB Low-Sulfur fuel (<15ppm sulfur by weight). The project owner shall further require as a condition of its construction contracts that all heavy construction equipment to the extent practical shall remain running at idle for no more than 5 minutes.

<u>Verification</u>: The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor's/subcontractor's heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer's specifications. The project owner shall maintain construction contracts on the site for six months following the start of commercial operation.

AQ-C2 The project owner shall employ the following measures to mitigate, to the extent practical, construction related emission impacts from off-road, diesel fired construction equipment. These measures include the use of oxidizing soot filters, oxidizing catalysts, diesel fuel certified to CARB ultra-low sulfur fuel standards (sulfur content 15 or less ppm) and diesel engines that are wither equipped with high pressure fuel injection, employ fuel injection timing retardation or are certified to EPA and CARB 1996 or better off-road equipment emission standards. Additionally, the project owner shall restrict idle time, to the extent practical, to no more than 5 minutes.

The use of each mitigation measure is to be determined by a Qualified Environmental Professional (QEP) or a qualified independent California Licensed Mechanical Engineer (ME). The QEP or ME is to be approved by the CPM prior to the submission of any reports. The QEP or ME will determine the mitigation measures to be used within the following framework.

Construction Mitigation Framework

1. No Measure or combination of measures shall be allowed to significantly delay the project construction or construction of related linear facilities.

2. No measure of combination of measures shall be allowed to cause significant damage to the construction equipment or cause a significant risk to on site workers or the public.

3. Engines certified to EPA and CARB 1996 or better off-road equipment emission standards **and** CARB certified low sulfur diesel fuel may be used in lieu of oxidizing soot filters and oxidizing catalysts.

The QEP or ME will, in consultation with the California Air Resources Board (CARB), submit for approval to the CPM a Construction Mitigation Plan, Reports or Change and Mitigation Implementation, and all Emergency Termination of Mitigation Reports as necessary, containing at a minimum the following:

Construction Mitigation Plan

The Mitigation Employment Plan shall be submitted to the CPM for approval prior to rough grading on the project site and will include:

1. A list of all diesel fuel burning, off-road, stationary or portable construction-related equipment to be used either on the project construction site or the construction sites of the related linear facilities.

2. All equipment listed under (1), shall be identified as either using engines certified to EAP and CARB 1996 or better off-road equipment emission standards, using diesel engines that are equipped with high pressure fuel injection, or using diesel engines that employ fuel injection timing retardation.

3. The determination of suitability of all equipment listed under (1) to work appropriately with an oxidizing catalyst shall be identified except as provided for in item 3 of the **Construction Mitigation Framework** above. If a piece of equipment is determined to be unsuitable for an oxidizing catalyst, the QEP or ME will provide an explanation as to the cause of this determination.

4. The determination of the suitability of all equipment listed under (1) to work appropriately with an oxidizing soot filter shall be identified except as provided for in item 3 of the Construction Mitigation Framework above. If a piece of equipment is determined to be unsuitable for an oxidizing soot filter, the QEP or ME will provide an explanation as to the cause of this determination.

5. Maximum idle times shall be identified for all equipment listed under (1).

6. The sulfur content of all diesel fuel to be burned in any equipment listed under (1) shall be identified.

Report of Change and Mitigation Implementation

The QEP or ME shall submit a Report of Change and Mitigation Implementation for approval to the CPM following the initiation of construction activities which contains at a minimum the cause of any deviation from the Construction Mitigation Plan measures that were implemented. Verification includes, but is not limited to, the following:

1. EPA or CARB engine certifications for item 2 of the **Construction Mitigation Plan**

2. A copy of the contract agreement requiring subcontractors to comply with the elements under item 2 of the **Construction Mitigation Plan.**

3. Confirmation of the installation of either oxidizing catalysts or oxidizing soot filters as identified in items 3 and 4 of the **Construction Mitigation Plan** or the cause preventing the identified installations.

4. A copy of the contract agreement requiring subcontractors to comply with the elements under item 5 of the **Construction Mitigation Plan**.

5. A copy of receipts of purchase of diesel fuel indicating the sulfur content as identified in item 6 of the **Construction Mitigation Plan**.

Emergency Termination of Mitigation Report

If a specific mitigation measure is determined to be detrimental to a piece of construction equipment or is determined to be causing significant delays in the construction schedule of the project or the associated linear facilities, the mitigation measure may be terminated immediately. However, notification must be sent to the CPM for approval containing an explanation for the cause of termination. All such causes are restricted to one of the following justifications and must be identified in any Emergency Termination of Mitigation report.

1. The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or power output due to an excessive increase in back pressure.
2. The measure is causing or reasonably expected to cause significant damage to the construction equipment engine**.**
3. The measure is causing or reasonably expected to cause a significant risk to nearby workers or the public.
4. Any other seriously detrimental cause which has approval by the CPM prior to the change being implemented.

Verification: The project owner will submit to the CPM for approval the qualifications of the QEP or ME at least 45 days prior to the due date for the Construction Mitigation Plan. The project owner will submit the Construction Mitigation Plan to the CPM for approval 60 calendar days prior to rough grading on the project site. The project owner will submit the Report of Change and Mitigation Implementation to the CPM for approval no later than 10 working days following the use of the specific construction equipment on wither the project site or the associated linear facilities. The project owner will submit any Emergency termination of Mitigation reports to the CPM for approval, as required, no later than 10 working days following the termination of the identified mitigation measure. The CPM will monitor the approval of all reports submitted by the project owner in consultation with CARB, limiting the review time for any one report to no more than 20 working days.

Verification: The project owner will submit to the CPM for approval the qualifications of the QEP or ME at least 45 days prior to the due date for the Construction Mitigation Plan. The project owner will submit the Construction Mitigation Plan to the CPM for approval 60 calendar days prior to rough grading on the project site. The project owner will submit the Report of Change and Mitigation Implementation to the CPM for approval no later than 10 working days following the use of the specific construction equipment on wither the project site or the associated linear facilities. The project owner will submit any Emergency termination of Mitigation reports to the CPM for approval, as required, no later than 10 working days following the termination of the identified mitigation measure. The CPM will monitor the approval of all reports submitted by the project owner in consultation with CARB, limiting the review time for any one report to no more than 20 working days.

AQ-C3 Prior to breaking ground at the project site, the project owner shall prepare a Construction Fugitive Dust Mitigation Plan that will specifically identify fugitive dust mitigation measures that will be employed for the construction of the Mountainview Power Plant and related facilities.

The Construction Fugitive Dust Mitigation Plan shall specifically identify measures to limit fugitive dust emissions from construction of the project site and linear facilities. Measures that should be addressed include the following:

- the identification of the employee parking area(s) and surface of the parking area(s);
- the frequency of watering of unpaved roads and disturbed areas;
- the application of chemical dust suppressants;
- the use of gravel in high traffic areas;
- the use of paved access aprons;
- the use of posted speed limit signs;
- the use of wheel washing areas prior to large trucks leaving the project site;
- the methods that will be used to clean tracked-out mud and dirt from the project site onto public roads; and,
- the use of on-site monitoring devices.

Verification: At least sixty (60) days prior to breaking ground at the project site, the project owner shall provide the CPM with a copy of the Construction Fugitive Dust Mitigation Plan for approval.

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

1,991 MMBTU/HR at 30 degrees Fahrenheit natural Gas Turbine No. 3A GE Model 7FA.04 with Dry Low NOx combustors DLN 2.6+ connected directly to a 177.1 MW (gross output at 59 degrees Fahrenheit) Electric Generator and a Heat Recovery Steam Generator with 135 MMBTU/HR Duct Burners connected to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3B). Turbine 3A, the HRSG, and steam turbine are all identified as ID No. D18 (A/N 500208) and the duct burners are identified as ID No. D21 (A/N 578178). Equipment D18 and D21 are both connected to a CO oxidation catalyst, No. 3-1 (ID No. C23) (A/N 562528), with 240 cubic feet of total catalyst volume, Selective Catalytic Reduction, No. 3-2 (ID No. C24) (A/N 562528), with 2,750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.5 feet wide with an ammonia injection grid, and share a common stack, Stack No. 3A (ID No. S26), with a height of 200 feet and diameter of 18 feet.

1,991 MMBTU/HR at 30 degrees Fahrenheit natural Gas Turbine No. 3B GE Model 7FA.04 with Dry Low NOx combustors DLN 2.6+ connected directly to a 177.1 MW (gross output at 59 degrees Fahrenheit) Electric Generator and a Heat Recovery Steam Generator with 135 MMBTU/HR Duct Burners connected to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3A). Turbine 3B, the HRSG, and steam turbine are all identified as ID No. D27 (A/N 578179) and the duct burners are identified as ID No. D30 (A/N 578179). Equipment D27 and D30 are both connected to a CO oxidation catalyst, No. 3-2 (ID No. C32) (A/N 562529), with 240 cubic feet of total catalyst volume, Selective Catalytic Reduction, No. 3-2 (ID No. C33) (A/N 562529), with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.5 feet wide with an ammonia injection grid, and share a common stack, Stack No. 3B (ID No. S35), with a height of 200 feet and diameter of 18 feet.

1,991 MMBTU/HR at 30 degrees Fahrenheit natural Gas Turbine No. 4A GE Model 7FA.04 with Dry Low NOx combustors DLN 2.6+ connected directly to a 177.1 MW (gross output at 59 degrees Fahrenheit) Electric Generator and a Heat Recovery Steam Generator with 135 MMBTU/HR Duct Burners connected to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 4B). Turbine 4A, the HRSG, and steam turbine are all identified as ID No. D36 (A/N 578180) and the duct burners are identified as ID No. D39 (A/N 578180). Equipment D36 and D39 are both connected to a CO oxidation catalyst, No. 4-1 (ID No. C41) (A/N 562530), with 240 cubic feet of total catalyst volume, Selective Catalytic Reduction, No. 4-1 (ID No. C42) (A/N 562530), with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.5 feet wide with an ammonia injection grid, and share a common stack, Stack No. 4A (ID No. S44), with a height of 200 feet and diameter of 18 feet.

1,991 MMBTU/HR at 30 degrees Fahrenheit natural Gas Turbine No. 4B GE Model 7FA.04 with Dry Low NOx combustors DLN 2.6+ connected directly to a 177.1 MW (gross output at 59 degrees Fahrenheit) Electric Generator and a Heat Recovery Steam Generator with 135 MMBTU/HR Duct Burners connected to a 212.4 MW (gross output at 59 degrees Fahrenheit) GE Model D11 steam turbine (common with turbine 3B). Turbine 3A, the HRSG, and steam turbine are all identified as ID No. D45 (A/N 578181) and the duct burners are identified as ID No. D48 (A/N 578181). Equipment D45 and D48 are both connected to a CO oxidation catalyst, No. 4-2 (ID No. C50)(A/N 562531), with 240 cubic feet of total catalyst volume, Selective Catalytic Reduction, No. 4-2 (ID

No. C51) (A/N 562531) with 2750 cubic feet of total volume 72 feet height, 1.5 feet long, 25.5 feet wide with an ammonia injection, and share a common stack, Stack No. 4B (ID No. S53), with a height of 200 feet and diameter of 18 feet.

AQ-1 During the final phase of construction, the operator shall be allowed to exceed normal operational and startup emission limits and operational constraints (**AQ-9, AQ-10, AQ-11, AQ-12, AQ-13** and **AQ-14**) and will be subject only to the limit prescribed in this Condition so that the turbine systems and controls can be fine tuned. This phase of construction is referred to herein as initial commissioning. The commissioning period shall not exceed 1,272 combined operating hours per two gas turbine power block from the time of initial startup. The power block is defined as two gas turbines that are connected to the same steam turbine. The project owner shall provide the District and Energy Commission with written notification of the initial startup date within two weeks of the startup.

During the commissioning period and the interim reporting periods prior to the CEMS becoming validated by the District, the project owner shall report NOx emissions by using the recorded fuel use data and the assumed emission factor of 32.32 lbs/mmscf. Such record shall be made, kept and maintained on file for a minimum of five years and shall be made available to the District and the Energy Commission upon request. The facility log shall indicate the date, number of operating hours and fuel consumed for each turbine and duct burner during the commissioning period.

Verification: The project owner and/or operator (project owner) shall report, the date of operation, the number of hours of operation, the natural gas fuel consumption (mmcf) and total NOx emissions (lbs) from initial commissioning to the California Energy Commission Compliance Project Manager (CPM) for each of the four gas turbines and duct burners in the monthly compliance report.

AQ-2 The owner/operator shall determine the hourly ammonia slip emissions from each exhaust stack for each gas turbine/HRSG train individually via both the following formulas.

District Requirement

NH3 (ppmv) = [a-b * (c * 1.2) / 1E6] * 1E6/b

Where:

a = NH3 injection rate (lb/hr) / 17 (lb/lbmol),

b = dry exhaust flowe rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx across the SCR (ppmvd at 15% O2)

The above described ammonia slip calculation procedure shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia for the District.

Energy Commission Requirement

NH3 (ppmv @ 15% O2) =((a-b * (c / 1E6)) * (1E6/b)*d,
Where:

a = NH3 injection rate (lb/hr) / 17 (lb/lbmol)
b = dry exhaust gas flow rate (lb/hr) / (29 (lb/lbmol), or
b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),
c = change in measured NOx concentration ppmv corrected to 15% O2 across catalyst, and
d = correction factor.

The correction factor shall be derived through compliance testing by comparing the measured and calculated ammonia slip. The correction factor shall be reviewed and approved by the CPM on at least an annual basis. The correction factor may rely on previous compliance source test results or other comparable analysis as the CPM finds the situation warrants. The above described ammonia slip calculation procedure shall be used for Energy Commission compliance determination for the ammonia slip limit as prescribed in Condition of Certification **AQ-11** and reported to the CPM on a quarterly basis as prescribed in Condition of Certification **AQ-8**.

An exceedance of the ammonia slip limit as demonstrated by the above Energy Commission formula shall not in and of itself constitute a violation of the limit. An exceedance of the ammonia slip limit shall not exceed 6 hours in duration. In the event of an exceedance of the ammonia slip limit exceeding 6 hours duration, the project owner shall notify the CPM within 72 hours of the occurrence. This notification must include but is not limited to: the date and time of the exceedance, duration of the exceedance, estimated emissions as a result of the exceedance, the suspected cause of the exceedance and the corrective action taken or planned. Exceedances of the ammonia limit that are less than or equal to 6 hours in duration shall be noted in a specific section within the Quarterly report (**AQ-8**). This section shall include, but is not limited to: the date and time of the exceedance, duration of the exceedance, and the estimated emissions as a result of the exceedance. Exceedances shall be deemed chronic if they total more than 500 hours per year (approximately 10% if the expected operation) for any dingle HRSG exhaust stack. Chronic exceedances must be investigated and redressed in a timely manner and in conjunction with the CPM though the cooperative development of a compliance plan. The compliance plan shall be developed to bring the project back into compliance first and foremost and shall secondly endeavor to do so in a feasible and timely manner, but shall not be limited in scope.

The owner/operator shall maintain compliance with the ammonia slip limit, redress excedances of the ammonia slip limit in a timely manner, and avoid chronic exceedances of the ammonia slip limit. Exceedances shall be deemed a violation of the ammonia slip limit if they are not properly redressed as prescribed herein.

The owner/operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

<u>Verification</u>: The project owner shall include ammonia slip concentrations averages on an hourly basis calculated via both protocols provided as part of the Quarterly Operational report required in Condition of Certification **AQ-8**. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date. The project owner shall submit to the CPM for approval a proposed correction factor to be used in the energy Commission formula at least once a year but not to exceed 180 days following the completion of the annual ammonia compliance source test. Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operations report (**AQ-8**) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedances of the ammonia slip limit within 60 days of the above confirmation.

AQ-3 The project owner shall install and maintain a continuous monitoring and recording system capable of measuring at least once every 15 minutes and recording measurements at least once every hour to accurately indicate the ammonia injection rate of the ammonia injection system.

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

AQ-4 The owner shall install and maintain a temperature gauge to accurately measure and record the temperature in the SCR catalyst. The system shall be accurate to within +/- 5 percent and shall be calibrated once every 12 months.

The operator shall install and maintain a pressure gauge to accurately indicate and continuously record the pressure drop across the SCR catalyst bed in inches of water column. The system shall be accurate to within +/-5 percent and shall be calibrated once every 12 months.

Such records shall be and maintained on site per District requirements.

<u>Verification</u>: The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature gage has been installed no later than 6 weeks after installation. The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been installed no later than 6 week after installation. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR temperature has been calibrated as required no later than 6 weeks after calibration. The project owner shall, on an annual basis, submit to the CPM a written statement by a California Certified Professional Engineer that the required SCR pressure gauge has been calibrated as required no later than 6 weeks after calibration.

AQ-5 The project owner shall install, maintain and operate no later than 90 days after the initial startup of the turbine continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to measure CO concentration in ppmv corrected to 15% oxygen on a dry basis and convert those CO concentrations to mass emission rates in units of pounds per hour (lbs/hr). The CEMS shall be capable of measuring at least over a 15-minute averaging period and shall record hourly mass emission rates on a continuous basis. The CEMS shall be installed and operated in accordance with an approved District Rule 218 CEMS plan application. The CEMS plan shall include a requirement for on going relative accuracy testing. The project owner shall NOT install the CEMS prior to receiving initial approval from the District.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission. The owner shall submit to the CPM a copy of the CEMS plan application submitted to the District and the initial written approval for installation from the District. No later than two weeks after initial startup date of each turbine, the project owner shall provide written notification to the District and CPM of the exact date of startup.

AQ-6 The project owner shall install, maintain and operate a continuous emissions monitoring system (CEMS) for each gas turbine exhaust stack to continuously measure the concentrations of NOx (in ppmv) and oxygen in percent, fuel flow rate, and operational status codes as defined in District Rule 2012 once every 15 minutes. In compliance with District Rule 2012, the project owner shall at least annually test the NOx CEMS for relative accuracy. The NOx CEMS shall record the combined NOx emissions from all four gas turbines and their respective duct burners whenever at least one gas turbine is in startup mode. The CEMS will convert all recorded NOx concentrations to mass emissions and record NOx mass emissions hourly and daily. The CEMS shall be installed and operating no later than 12 months following first fire (District Rule 2021(h)(6)). From the time of first fire until the CEMS are certified, the project owner shall comply with the fuel monitoring requirements of District Rule 2012(h)(2) and 2012(h)(3)

Verification: The project owner shall make the site and appropriate records available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-7 The project owner shall electronically report total daily mass emissions of NO_x and daily operational status codes to the District Central NO_x Station in compliance with District rule 2012 (c)(3)(A).

Verification: The project owner shall submit to the District Monthly Emissions Reports in the manner and form specified by the District within 15 calendar days of the close of each of the first eleven months of the compliance year (District Rule 2012(c)(3)(B)). The Monthly Emissions Report will include mass emissions of NOx on a monthly, daily and hourly basis within the reporting period. The project owner shall submit the Monthly Emissions Report to the CPM as part of the Quarterly Operational Report (see **AQ-8**).

AQ-8 The project owner shall submit to the Commission, Quarterly Operational Reports that include the fuel use associated with each gas turbine train (both gas turbine and duct burner), in addition to the CO and NOx CEMS recorded data for each gas turbine exhaust stack (see **AQ-5** and **AQ-6**) on an hourly basis.

Verification: The project owner shall submit the Quarterly Operational Reports as specified herein to the CPM no later than 30 days following the end of each calendar quarter.

AQ-9 The project owner shall vent the gas turbine and duct burners to the SCR and oxidation catalyst control whenever the turbines or duct burners are in operation, including startup and normal operation.

Verification: The project owner shall submit to the CPM a written statement by a California Certified Professional Engineer that the gas turbine and HRSG exhausts connections to the SCR and oxidation catalysts are operational and air tight installed no later than 6 weeks after installation.

AQ-10 Startup is defined for a gas turbine/HRSG train as beginning when fuel is introduced into the turbine's combustor, and ending immediately prior to the first 15-minute period when both the NOx and CO limits in Conditions **AQ-11** are met. Cold-Startup is defined as a startup, as previously defined, which directly follows at least 72 hours of non-operation of the turbine. Shutdown is defined for a gas turbine/HRSG train as beginning at the start of the first 15-minute period when the NOx and CO limits in Condition **AQ-11** are not met, and ending with the flow of fuel to the turbine's combustor ceases. Combustor-Tuning is defined as all manufacturer recommended activities required to ensure safe and reliable steady state operation of the gas turbine following the replacement of one (or more) of the turbine combustors. The project owner shall notify the District (via e-mail at REFINERYENERGY@AQMD.GOV) and the CPM (by written letter) within two weeks of combustor tuning activities. The total duration of startups and shutdowns shall not exceed 4 hours per gas turbine/HRSG per day. The duration of Cold-Startups may not exceed 6 hours per gas turbine/HSRG per day. The duration of Combustor-Tuning may not exceed 6 hours per gas turbine/HRSG per day. While gas turbine is in startup mode, the NOx and CO emission limits in Condition **AQ-11** shall not apply for that turbine. During a Startup, Shutdown, Cold Startup or Combustor Tuning event the following emission limits shall apply as indicated:

NOx Emission Limit	Averaging Time	Operational Requirements
80 lbs/hour	1 hour	Applies only to a single turbine/HRSG train during Combustor-Tuning event.
160 lbs/hour	3 hours, rolling	Applies only to a single turbine/HRSG train only during a Startup or Cold-Startup event.
320 lbs/hour	1 hour	Applies to the combined emissions of all four turbnine/HRSG trains whenever 1 or more turbines are in Startup or Cold-Startup mode.

Verification: The project owner shall submit fuel use, NOx emissions and operational status on an hourly basis during each startup, shutdown, Cold-Startup or Combustor Tuning event for each gas turbine in the Quarterly Operational Reports (see **AQ-8**).

AQ-11 Except during startup, shutdown, Cold-Startup, Combustor Tuning, initial commissioning and the exceptions noted below, emissions from each gas turbine exhaust stack shall not exceed the following limits:

NOx (measured as NO2):	2.0 ppm at 15% oxygen on a dry basis averaged over one hour and 14.22 lbs/hour.
CO:	6.0 ppm at 15% oxygen on a dry basis averaged over 1 hours and 25.91 lbs/hr.
SOx (measured as SO2):	1.42 lbs/hr
VOC:	4.96 lbs/hr
PM10:	11.0 lbs/hr
Ammonia:	5 ppm at 15% oxygen on a dry basis

Exceptions:

The NOx limit shall not apply to the first fifteen 1-hour average NOx emissions that are above 2.0 ppmv, dry basis at 15% O2, in any rolling 12-month period for each combustion gas turbine provided that it meets all of the following requirements A, B, C and D.

A. This equipment operates under any one of the qualified conditions described below:

   a) Rapid combustion turbine load changes due to the following conditions:

      - Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control; or

      - Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load

   b) The first two 1-hour reporting periods following the initiation/shutdown of an evaporative cooler supply pump

   c) The first two 1-hour reporting periods following the initiation of HRSG duct burners

   d) Events as the result of technological limitation identified by the operator and approved in writing by the AQMD Executive Officer or his designees and the CPM.

B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 2004(i).

C. The qualified operating conditions described in (A) above must be recorded in the plant's operating log within 24 hours of the event , and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the data and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1- hour average limit.

D. The a-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O2.

All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emissions rated as required by this permit.

Verification: The project owner shall submit emission calculations to demonstrate compliance for the NOx and CO limits and source tests, as required in Condition **AQ-15, AQ-16** and **AQ-17**, to demonstrate compliance with SOx, VOC and PM10 emission limits in the Quarterly Operational Reports (see **AQ-8**). Within 5 working days of the occurrence of an exception as described within this Condition, the owner/operator shall notify the CPM. Within 21 working days, of the occurrence for an exception as described within this Condition, the owner/operator shall submit to the CPM a complete report of the exception event. That report must include, but is not limited to: the date, time, duration and cause of the occurrence, the emissions (in total mass and hourly concentration normalized to 15% O2) because of the occurrence and the evidence required in element (B) above.

AQ-12 Except for initial commissioning, but including startup, shutdowns, Cold-Startups and Combustor-Tunings the emissions from each gas turbine exhaust stack shall not exceed the following limits:

CO	694 lbs per day
CO	8,610 lbs per month
VOC	3,568 lbs per month
PM10	7,725 lbs per month
SOx	1,005 lbs per month

Protocol: The project owner shall confirm compliance with the monthly limits by using the monthly fuel use data of each gas turbine and duct burner pair and the following emission factors:

VOC:	2.51 lbs/mmscf
PM10:	5.57 lbs/mmscf
SOx (measured as SO2):	0.71 lbs/mmscf

Compliance with the CO monthly limit shall be confirmed through the valid (per District Rule 218) CO CEMS or, absent valid CO CEMS, but the monthly fuel use data and the following emission factors:

During Commissioning	114.47	lbs/mmscf
Following Commissioning	13.10	lbs/mmscf

Verification: The project owner shall submit the monthly fuel use data and emission calculations to the CPM in the Quarterly Operation Reports (**AQ-8**).

AQ-13 **Deleted**

AQ-14 Except for initial commissioning, but including startup and shutdowns, the emissions from each gas turbine exhaust stack shall not exceed the following limits:

PM10: Either 11 lbs/hr or 0.01 grains per standard cubic foot at 3% oxygen averaged over 15 consecutive minutes (or other averaging period specified by the District)]

Verification: The project owner shall submit source tests as required by Condition **AQ-17** confirming verification of the condition.

AQ-15 The project owner shall conduct an initial source test and annually thereafter for NOx, CO and NH3 and once every three years thereafter for SOx, VOC and PM10 of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the CPM 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- The initial source test shall be conducted no later than 180 days following the date of first fire.
- The District and CPM shall be notified at least 7 days prior to the date and time of a source test.
- The source test shall be conducted with the gas turbine operating under loads of 50%, 75% and 100% of maximum.
- The source test shall be conducted to determine the oxygen levels in the exhaust.
- The source test shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The source test shall be conducted for the pollutants listed using the methods averaging times, and test locations indicated and as approved by the CPM:

Pollutant	Method	Averaging Time	Test Location
NOx	District Method 100.1	1 hour	Outlet of SCR
CO	District Method 100.1	District Approved	Outlet of SCR
SOx	District approved method	District Approved	Fuel Sample
VOC	District approved method	1 hour	Outlet of SCR
PM10	District approved method	District Approved	Outlet of SCR

Ammonia	District Method 5.3 and 207.1 or EPA Method 17	1 hour	Outlet of SCR

- The source test results shall be submitted to the District and the CPM no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
    1. ppmv corrected to 15% oxygen,
    2. pounds per hour,
    3. pounds per million cubic feet of fuel burned and
    4. additionally, for PM10 only, grains per dry standard cubic feet of fuel burned.

Verification: The project owner shall submit the proposed protocol for the source tests 45 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit 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 7 days prior to a source test date.

AQ-16 The project owner shall conduct source testing of each gas turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the CPM no later than 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted quarterly for the first 12 months of operation and annually thereafter.
- NOx concentrations as determined by CEMS shall be simultaneously recorded during the ammonia test. If the NOx CEMS is inoperable, a test shall be conducted to determine the NOx emission by using District Method 100.1 measured over a 60 minute averaging period.
- Source testing shall be conducted to determine the ammonia emissions from each gas turbine exhaust stack using District Method 5.3 and 207.1 or EPA Method 17 measured over a 1 hour averaging period.
- The District and CPM shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the District and CPM within 45 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The test shall be conducted when the equipment is operating at 80 percent load or greater.
- All emission data is to be expressed in the following units:

1. ppmv corrected to 15% oxygen,
2. pounds per hour,
3. pounds per million cubic feet of fuel burned

Verification: The project owner shall submit the proposed protocol for the source tests 45 days prior to the proposed source test date to both the District and CPM for approval. No later than 7 days prior to the proposed source test, the project owner shall notify the District and CPM of the source test date and time of the source test. The project owner shall submit source test results no later than 45 days following the source test date to both the District and CPM.

AQ-17 The project owner shall conduct source testing of each gas turbine exhaust stack to verify compliance with the PM10 emission limits stated in Condition **AQ-14**, in accordance with the following requirements:

- The project owner shall submit a source test protocol to the District and the Commission 60 days prior to the proposed initial source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of District Rule 304, and a description of all sampling and analytical procedures.
- Source testing shall be conducted to measure PM10 emissions from each gas turbine exhaust stack using District Method 5.1.
- Source testing shall be conducted using natural gas operating at minimum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The source test shall be conducted no later than 6 months after this time limit has been exceeded.
- Source testing shall be conducted using natural gas operating at maximum load under normal operating conditions, if natural gas is burned more than 120 consecutive hours or 200 hours accumulated over any 12 consecutive months. The source test shall be conducted no later than 6 months after this time limit has been exceeded.
- Source testing frequency shall be annual, but may be reduced to once every 5 years under the highest emitting load if three consecutive annual test results show compliance condition **AQ-14**.
- Source testing shall not be required for any one year for which the equipment is not in operation.
- Source test shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- Source test results shall be submitted to the District and the Commission no later than 60 days after the source test was conducted.
- All emission data is to be expressed in the following units:
  1. pounds per hour
  2. pounds per million cubic feet of fuel burned and
  3. grains per dry standard cubic feet of fuel burned.

Verification: The project owner shall submit the proposed protocol for the source tests 60 days prior to the proposed source test date to both the District and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the District and CPM.

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

Internal combustion engine, emergency power, diesel Caterpillar 3512B, turbocharged, aftercooled, 2,155 BHP A/N 500222 (ID. No. D61).

AQ-18 The project owner shall not use fuel oil containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-21**).

AQ-19 **Deleted**

AQ-20 The project owner shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the emergency IC engine.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-21 The project owner shall maintain records in a manner approved by the District for the following parameters or items in regards to the emergency IC engine:

- Date of operation,
- elapsed time of operation (in hours) and
- the reason for operation.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-22 The project owner shall use the emergency IC engine only during utility failure periods, except for maintenance purposes.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-21**).

AQ-23 The project owner shall limit the operating time of the emergency IC engine to no more than ~~200~~ 199 hours per year.

Verification: The project owner shall submit the recorded data specified in condition **AQ-21** on an annual basis as part of the fourth Quarter Operational Report (see **AQ-8**).

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

Internal combustion engine, emergency fire pump, diesel Clarke Model JW6H-UF60, 9.7^0 timing retard, turbocharged, aftercooled, 375 BHP A/N 366156 (ID. No. D58).

AQ-24 The project owner shall not use fuel oil containing sulfur compounds in excess of 15 ppm by weight as supplied by the supplier.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission (see **AQ-27**).

AQ-25 The project owner shall set and maintain the fuel injection timing of the fire pump IC engine at 9.7^0 retarded relative to standard timing.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-26 The project owner shall install and maintain a non-resettable elapsed time meter to accurately indicate the elapsed operating time of the fire pump IC engine.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-27 The project owner shall maintain records in a manner approved by the District for the following parameters or items in regards to the fire pump IC engine:

- Date of operation,
- elapsed time of operation (in hours) and
- the reason for operation.

Verification: The project owner shall maintain records on site for a minimum of five years and make them available for inspection by request from representatives of the District, CARB, EPA or the Commission.

AQ-28 The project owner shall limit the operating time of the fire pump IC engine to no more than 199 hours per year.

Verification: The project owner shall submit the recorded data specified in condition **AQ-27** on an annual basis as part of the fourth Quarter Operational Report (see **AQ-8**).

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

The two cooling towers associated with the new gas turbine units (Units 3 and 4), each are 147,000 gal/min in capacity, have 10 cells, two rows side-by-side, forced vent and have a drift rate of 0.0006%.

AQ-29 For the two cooling towers associated with Units 3 and 4, the project owner shall submit drift eliminator design details and vendor specific justification for the correction factor to be used to correlate blowdown TDS to drift TDS and the amount of drift that stays suspended in the atmosphere in the equation in Condition **AQ-34** to the Commission at least 30 days prior to commencement of construction.

Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the CPM.

AQ-30 For the two cooling towers associated with Units 3 and 4, the project owner shall submit cooling tower design details including the cooling tower type and materials of construction to the Commission at least 30 days prior to commencement of construction, and at least 90 days before the tower is operated.

Verification: The project owner shall submit the information required above to the CPM 30 days prior to the commencement of construction of the cooling towers.

AQ-31 The project owner shall NOT use hexavalent chromium containing compounds in the cooling tower circulating water.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA or the Commission.

AQ-32 The project owner shall design and build the cooling towers for units 3 and 4 such that the drift eliminator drift rate of the cooling towers does not exceed 0.0006%.

Verification: The project owner shall submit documentation from the selected cooling tower vendor that verifies the drift efficiency to the CPM 30 days prior to commencement of construction of the cooling towers.

AQ-33 The project owner shall limit the PM10 emissions from the cooling towers associated with units 3 and 4 as follows:

- Each 10 cell cooling tower is not to exceed 70.1 lbs/day

Verification: The project owner shall submit data and calculations on annual basis to the CPM as discussed in condition **AQ-34**.

AQ-34 The project owner shall demonstrate compliance with the PM10 daily emission limit (see **AQ-33**) as follows:

PM10 lb/day = circulating water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate * correction factor.

Verification: The project owner shall compile the required data on a daily basis and submit the data and calculations annually in the fourth Quarter Operational Report (see **AQ-8**) to the CPM.

AQ-35 The project owner shall perform circulating water sample analyses by independent laboratory within 90 days of initial operation and weekly thereafter to determine the TDS within the cooling tower water. Alternatively, the project owner shall continuously measure cooling tower basin water conductivity for use in the calculation required by condition **AQ-34**.

<u>Verification</u>: The project owner shall compile the required analyses and maintain the data on site for a minimum period of two years. The project owner shall make the site available for inspection by representatives of the District, CARB, EPA or the Commission.

THE FOLLOWING CONDITION OF CERTIFICATION PERTAINS TO THE GAS TURBINES, DUCT BURNERS AND EMERGENCY ENGINES

AQ-36 The following condition is applicable to each of the four combustion turbines (D19, D27, D36, D45):

A. The gas turbine~~s~~ shall not be operated unless the facility holds 114,412 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the gas turbine~~s~~ shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 107,552 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

The following condition is applicable to each of the four duct burners (D21, D30, D39, D48):

B. The duct burner shall not be operated unless the facility holds 7,758 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the duct burner shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 7,293 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

The following condition is applicable to the emergency fire pump engine (D58):

C. The emergency fire pump IC engine shall not be operated unless the facility holds 841 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the emergency fire pump IC engine shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 841 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

The following condition is applicable to the emergency IC engine (D61):

D. The emergency IC engine shall not be operated unless the facility holds 1,549 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first compliance year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, the emergency IC engine shall not be operated unless the operator demonstrates to the District that, at the commencement of each compliance year after the first compliance year of operation, the facility holds 1,549 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual 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.

<u>Verification</u>: The project owner shall submit to the CPM copies of all RECLAIM reports filed with the District in each Quarterly Operational Report. (see **AQ-8**).

THE FOLLOWING CONDITIONS OF CERTIFICATION PERTAIN TO THE FOLLOWING EQUIPMENT:

Storage tank, TK-3, serving SCRs 3-1, 3-2,4-3, 4-4 with a vapor return line, 36,000 gallons (ID No. D60).

AQ-37 The project owner shall vent the aqueous ammonia storage tank during filling procedures only to the vessel from which it is being filled.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

AQ-38 The project owner shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig in the aqueous ammonia storage tank.

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB, EPA and the Commission.

REFERENCES

CEC 2001 – California Energy Commission – Commission Decision (TN 19233), March 21, 2001

CEC 2001a – California Energy Commission – Notice of Exemption: Approval of request to Modify Mountainview Power Project Conditions of Certification AQ-C2 to Allow the Use of Ultra-Low Sulfur Fuel in Conjunction with 1996 ARB Certified Engines in Place of Oxidizing Soot Filters (TN 21397). July 12, 2001

CEC 2001b– California Energy Commission – Approval of Request for General Arrangement Amendment Changes to Conditions of Certification AQ-9 and AQ-10 Addition of Condition WQ-8 (TN 22349). September 18, 2001

CEC 2002– California Energy Commission – Approval of Project Changes: Allowing use of Caterpillar Model 3512B and Deletion of Condition of Certification AQ-19 (TN 24026). January 11, 2002

CEC 2004– California Energy Commission –Order Approving a Petition to Modify Air Quality Conditions of Certification (TN 32334). September 14, 2004

CEC 2006– California Energy Commission –Order Approving Petition to Increase The Volatile Organic Compound VOC Emission Limits and Change The Equipment Description of The Emergency Diesel Generation (TN 37314). July 7, 2006

SCAQMD 2016 – South Coast Air Quality Management District – Permit to Operate Evaluation AN 578178-81 (TN 210153-2), docketed February 4, 2016

SCAQMD 2016a – South Coast Air Quality Management District – Proposed Title V Permit Revision AN 569066 (TN 210153-3), docketed February 4, 2016

SCAQMD 2016b – South Coast Air Quality Management District – Public Notice AN 569066 (TN 210153-3), docketed February 4, 2016

SCAQMD 2016c – South Coast Air Quality Management District – Letter to EPA RE: Transmittal of Proposed Title V Renewal Permit (TN 210153-3), docketed February 4, 2016

SCAQMD 2016d – South Coast Air Quality Management District – Statement of Basis AN 569006 (TN 210153-2), docketed February 4, 2016

SCE 2016 – Mountainview Generating Station –Hot Gas Path Component Replacement (TN 207273), docketed January 11, 2016.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
TRAFFIC AND TRANSPORTATION
Prepared by James Adams and Joseph Hughes

SUMMARY OF CONCLUSIONS

Staff has reviewed the Petition to Amend (PTA) the Mountainview Generating Station (Mountainview) to replace/upgrade certain internal components in the combustion turbine hot gas path. Implementation of existing Conditions of Certification **TRANS-1**, **TRANS-4**, and **TRANS-5** would ensure ground-level traffic impacts are less than significant and the project remains in compliance with applicable laws, ordinances, regulations, and standards (LORS). With implementation of staff's proposed new Condition of Certification **TRANS-8** regarding pilot notification and awareness, impacts on aviation safety would be less than significant.

INTRODUCTION

Traffic in and out of the Mountainview site is higher during periodic maintenance overhauls than it is under normal operating conditions. According to the Final Commission Decision, Mountainview has a permanent operating labor force of approximately 33 full-time employees, working and commuting over three shifts. For the hot gas path replacement planned for March of 2016, the workforce is expected to reach a peak of approximately 150 individuals per shift. Each day's work will involve two 12-hour shifts, each changing at 7 a.m. and 7 p.m. Work is expected to commence in late-March 2016 and conclude in late-April or early-May 2016. Staff has evaluated whether the traffic associated with the proposed hot gas path replacement would significantly affect the roadways in the project area, and also whether thermal plumes emitted from the upgraded turbines could affect the safety of aircraft using the San Bernardino International Airport (SBA) located about 0.7 mile north of the Mountainview site.

SUMMARY OF THE DECISION

The Final Commission Decision found that commuting construction workers, estimated to peak for 6 months at 568 workers, could cause an unacceptable level of congestion on San Bernardino Avenue during peak commute hours. To mitigate this impact, Condition of Certification **TRANS-4** required implementation of a traffic control plan that included measures such as staggered arrival and departure times, car-pooling and use of alternative routes. The analysis of Mountainview's potential to impact the operation of the SBA was limited to a review of whether the exhaust stacks would be a physical obstruction to navigable airspace. The Decision found with aviation warning lighting and marking on the stacks required by the FAA to insure air safety, the project impacts would be insignificant. For this analysis, staff confirmed with the SBA Control Tower

Manager that the exhaust stacks have flashing strobe lights during the day and blinking red lights at night.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS COMPLIANCE

Although the petition identifies equipment laydown areas onsite, and delivery entrances along Mountain View Avenue, the size and number of delivery trucks is not provided. Conformance with Caltrans and San Bernardino County limitations on vehicle sizes and weights on roadways is ensured by Condition of Certification **TRANS-1**. **TRANS-1** requires the project owner or its contractor to obtain necessary transportation permits from Caltrans and all relevant jurisdictions for roadway use.

ENVIRONMENTAL IMPACT ANALYSIS

In a telephone conversation on February 5, 2016, with the Tom Ware, representative for the project owner, workers and delivery trucks would travel to the Mountainview site along the same route identified in the Final Decision – exiting Interstate 10 (I-10) at Mountain View Avenue and traveling north to the site. The increase in workforce-related traffic could have an impact at a specific local roadway intersection. In discussions with the cities of Redlands and San Bernardino, the intersection of Mountain View Avenue and San Bernardino Avenue has a level of service (LOS) of F during the PM peak hours (4pm-6pm). With the exception of this roadway intersection, Mountain View Avenue from I-10 to the project site will continue to operate at LOS B during the AM peak hour and LOS C during the PM peak hour. Further impacting the congested Mountain View/San Bernardino intersection during the PM peak hours could be avoided with implementation of the traffic control plan as required under **TRANS-4.**

No impacts to the roadway system would occur as a result of worker parking or equipment storage as existing areas on the Mountainview site will accommodate the anticipated workforce and equipment storage. **TRANS-5** (roadway repairs) would address any roadway damage that may be caused by equipment delivery trucks.

The analysis of impacts on aviation operations at the San Bernardino International Airport was limited to an assessment of whether the project’s exhaust stacks would be a physical obstruction to navigable airspace. The potential for Mountainview’s exhaust plumes to impact aviation activities was not considered or analyzed in the October 2000 Final Staff Assessment or the March 2001 Energy Commission Decision. Staff’s analysis of aviation safety impacts from power plant projects changed substantially after the Blythe Energy Project (BEP) (99-AFC-08) began operating in July 2003. Shortly after the BEP began operating, staff was advised that pilots were experiencing moderate to severe turbulence while flying over the BEP facility. Since that time, staff performs a thermal plume modeling analysis for any power plant in relatively close proximity to an operating airport (approximately three miles or less). If appropriate, mitigation measures are proposed to require notification of the Federal Aviation

Administration (FAA) and pilots using the affected airport to avoid low altitude flights over the power plant.

Using the Spillane Methodology, staff calculated plume velocities for two ambient cases (approximately 30°F and 59°F), with and without duct firing, and before and after the requested hot gas path upgrade. The results show that for the 59°F ambient condition, without duct firing, the plume velocity would drop to 4.3 m/s (staff's threshold critical velocity at which aircraft may experience moderate to severe turbulence) at a height of 620 feet before the upgrade, and 640 feet after the requested upgrade. For the (approximate) 30°F ambient condition, without duct firing, the plume velocity would drop to 4.3 m/s at a height of 695 feet before the upgrade, and 800 feet after the upgrade, an increase of 105 feet. The 30°F ambient condition is somewhat conservative as the monthly average lows for December and January (the coldest months) in San Bernardino are 42°F.

Traffic and Transportation Table 1 shows the exhaust parameters analyzed as a result of the proposed combustion turbine hot gas path upgrade.

Table 1
Exhaust Parameters Post Proposed Hot Gas Path Upgrade

Parameter	**CTG/HRSG**					
Number of Stacks	4					
Stack Height (ft)	200					
Stack Diameter (ft)	18					
Distance Between Stacks (ft)	178.26					
Ambient Temperature	26°F		59°F		115°F	
Ambient Relative Humidity	60.00%		60.00%		13.00%	
Duct Firing	Yes	No	Yes	No	Yes	No
Exhaust Temperature (°F)	NA	199	NA	198	NA	199
Exhaust Velocity (ft/s)	NA	70	NA	65.6	NA	62.6

Source: Petition to Amend (TN 207273), Attachment B.

Traffic and Transportation Table 2 shows the current exhaust parameters used to analyze existing thermal plumes.

Table 2
Current Stack Parameters

Ambient Temperature	**30°F**		**59°F**		**102°F**	
Duct Firing	Yes	No	Yes	No	Yes	No
Exhaust Temperature (°F)	187.736	192.722	189.734	196.736	194.738	199.724
Exhaust Velocity (ft/s)	65.22	65.52	63.03	63.55	60.53	60.79

Source: AFC Volume 2, Table G.5.1

Traffic and Transportation Table 3 compares the thermal plume velocities before and after the proposed combustion turbine hot gas path upgrade and provides the heights at which the plume velocities are expected to drop to 4.3 m/s (staff's threshold critical velocity at which aircraft may experience moderate to severe turbulence).

Table 3
Critical Heights for Thermal Plumes

Exhaust Parameters	Ambient Case (°F)	Duct Firing	Number of Stack Plume Overlap	Height Velocity Drops to 4.3 m/s (feet)
Pre Upgrade	30	No	1	695
	30	Yes	1	680
	59	No	1	620
	59	Yes	1	610
Post Upgrade	26	No	1.15	800
	59	No	1	640

Source: Staff derived using the Spillane Methodology.

The Mountainview site is located approximately 3,800 feet south of the SBA at an elevation of 1,105 feet above mean sea level (MSL). Information from the AirNav website shows the airport is publicly owned and operated as a general aviation airport with an average of 84 aircraft operations per day. SBA has one runway: Runway 6/24 which is 10,000 feet long and 200 feet wide with a traffic pattern altitude of 1,959 feet MSL. The airport elevation is approximately 1,100 feet MSL. The SBA Director of Aviation Safety advised staff that aircraft do fly over the Mountainview site at 800-900 feet above ground level (AGL). The SBA Control Tower Manager said he has not received any complaints of turbulence from pilots to date, and he does not believe an increase of 105 feet in elevation of the thermal plumes is a significant increase.

Nonetheless, because aircraft presently fly over the Mountainview site as low as the height the 4.3 m/s velocity thermal plumes are predicted to occur, staff believes it is advisable to require the project owner to consult with the FAA to notify all pilots using the SBA and airspace above Mountainview of potential air hazards from low-altitude overflight of the facility. Staff has proposed new Condition of Certification **TRANS-8** to ensure pilots are aware that overflight below 1,000 feet AGL of the Mountainview facility should be avoided.

CONCLUSIONS AND RECOMMENDATIONS

Implementation of existing Conditions of Certification **TRANS-1**, **TRANS-4**, and **TRANS-5** would ensure ground-level traffic impacts are less than significant and the project remains in compliance with applicable laws, ordinances, regulations, and standards. Implementation of staff's proposed Condition of Certification **TRANS-8** (pilot notification and awareness), would ensure any impacts to aviation safety would be less than significant. In addition, the project modification would not significantly affect any population, including the Environmental Justice population as shown in the Environmental Justice Population Figure.

PROPOSED NEW CONDITION OF CERTIFICATION

TRANS-8 Pilot Notification and Awareness

The project owner shall initiate the following actions:

• Submit a letter to the Federal Aviation Administration (FAA) requesting a Notice to Airmen (NOTAM) be issued advising pilots of the location of the Mountainview Generating Station and recommending avoidance of overflight of the project site below 1,000 feet above ground level (AGL). The letter should also request that the NOTAM be maintained in active status until the Los Angeles Sectional Chart and Airport Facility Directories (AFDs) identified below have been updated.

• Submit a letter to the FAA requesting a power plant depiction symbol be placed at the Mountainview Generating Station site location on the Los Angeles Sectional Chart with a notice to "avoid overflight below 1,000 feet AGL".

• Submit a request to the San Bernardino International Airport Manager to add a new remark to the Automated Surface Observing System (ASOS) identifying the location of the Mountainview Generating Station and advising pilots to avoid direct overflight below 1,000 feet AGL as they approach or depart the airport.

• Submit a letter to the Southern California Terminal Radar Approach Control (TRACON) requesting that aerodrome remarks describing the location of the Mountainview Generating Station plant and advising against direct overflight below 1,000 feet AGL to the:

• FAA Airport/Facility Directory – Southwest U.S.

• Jeppesen Sanderson Inc. (Airway Manual Services - Western U.S. Airport Directory)

• Pilots Guide to California Airports

Verification: No later than 60 days after the project owner completes replacement of the Advanced Gas Path components, the project owner shall submit draft language for the letters of request to the FAA (including Southern California

(TRACON) and San Bernardino International Airport) to the CPM for review and approval.

Within 60 days after CPM approval of draft language for the letters of request to the FAA (including Southern California TRACON), the project owner shall submit the letters of request to the FAA (including Southern California TRACON) and San Bernardino International Airport. The letters shall request a response within 30 days and a timeline for implementing the suggested remarks in identified publications and designation on the chart mentioned above. The project owner shall submit copies of these requests to the CPM. A copy of any resulting correspondence shall be submitted to the CPM within 10 days of receipt. If the FAA does not respond within 30 days, the project owner shall contact the CPM.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
BIOLOGICAL RESOURCES
Timithy Singer

INTRODUCTION

The proposed project modification to the Mountainview Generating Station (Mountainview) consists of replacing existing components of the combustion turbines with Advanced Gas Path components. There are periodic overhaul outages at the Mountainview facility, and installation of the components detailed in the Petition to Amend (PTA) will occur during the regularly scheduled 'Spring 2016' plant overhaul on Units 3 and 4. These outages are planned to start in late March 2016 and finish in late April or early May 2016.

CONCLUSIONS AND RECOMMENDATIONS

Staff evaluated the potential for impacts to biological resources from three aspects of the proposed project modification and its associated activities: noise generated by traffic to, from, and on the site; task lighting used during installation of the turbine components; and nitrogen deposition due to increased NOx emissions compared to past operating emissions.

In regards to noise and lighting, it is staff's opinion that the project modification would have a less than significant impact on biological resources. All of the project activities would occur wholly within the confines of the disturbed, paved site. Additionally, the Santa Ana River riparian zone along the northern edge of the site has no known sensitive species occurrences in the California Natural Diversity Database. Implementation of Condition of Certification **BIO-1** in the Final Commission Decision, which requires the project owner to minimize light and noise to the extent possible at the Mountainview site during construction activities, would ensure any impacts remain less than significant.

In regards to nitrogen deposition, despite the fact that annual NOx emissions will be increasing as a result of the anticipated higher dispatch of the post-upgraded facility (see PTA page 19, Table 2: Projected Actual Emissions Calculations), annual NOx emissions will be less than the amount considered in the impact analysis for the licensed project. Staff had concluded in the 2000 Staff Assessment there would be no impact on sensitive native plants as result of nitrogen deposition, and this conclusion is unchanged.

The proposed project modifications would result in less than significant impacts to biological resources. All of the project activities would occur wholly within the confines of the disturbed, paved site. Additionally, the Santa Ana River riparian zone along the northern edge of the site has no known sensitive species occurrences in the California Natural Diversity Database. Implementation of Condition of Certification **BIO-1** in the Final Commission Decision, which requires the project owner to minimize light and noise to the extent possible at the Mountainview site during construction activities, would ensure any impacts remain less than significant.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
EFFICIENCY AND RELIABILITY
Shahab Khoshmashrab

INTRODUCTION

The replacement of certain internal components in the gas turbine hot gas path would not have a significant effect on power plant efficiency or reliability.

CONCLUSIONS AND RECOMMENDATIONS

The proposed amendment requests to replace the existing combustion turbine hot gas path components with advanced gas path components on the four existing combustion turbines. The new hot gas path replacement components would improve the heat rate, and thus, fuel efficiency of the power plant by 1.1 percent. This is insignificant; nonetheless it is worth noting. This project change would result in less start-ups and would slightly extend major maintenance intervals, marginally improving power plant availability.

INTRODUCTION

The replacement of certain internal components in the gas turbine hot gas path would not have a significant impact on use and storage of hazardous materials at the facility.

CONCLUSIONS AND RECOMMENDATIONS

During the installation of the advanced combustion components for the existing turbines, several hazardous materials will be used on-site. Similar to equipment maintenance activities, these materials would include solvents, gasoline, lubricants, and welding gases which are already included in the annual compliance report under the existing **HAZ-1** condition. No extremely hazardous or regulated hazardous materials would be used on-site specifically for the advanced combustion components for the existing turbines. Therefore, with petitioner’s continued compliance with existing conditions of certification, **HAZ-1** specifically, the proposed modification would not have a significant impact on the off-site public or the environment and would continue to comply with all applicable LORS.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
LAND USE
Ellen LeFevre

INTRODUCTION

The proposed replacement of existing combustion turbine components with Advanced Gas Path upgraded components will be within the licensed project boundaries and will have no significant land use impacts.

CONCLUSIONS AND RECOMMENDATIONS

The proposed amendment requests to replace certain internal components in the gas turbine hot gas path with Advanced Gas Path components on the four existing combustion turbines. The current installed hot gas path components are scheduled to be replaced during the planned major maintenance outage in late March 2016 and conclude in late April 2016 or early May 2016. The modifications will use existing onsite equipment lay-down areas and will not require construction of new equipment lay-down staging areas. The Mountainview facility is located in a predominantly commercial/industrial area of Redlands, California.

The proposed amendment would not cause an impact to the California Environmental Quality Act Guidelines, Appendix G II and X.
The Amendment would have no significant land use impacts. In addition, the project modification would not affect any population including the Environmental Justice population as shown in the Environmental Justice Population Figure and Table.

The Land Use Conditions of Certification in the March 2001 Energy Commission Decision would not apply to the amendment. These conditions are:

- **LAND-1**: Provide the city of Redlands with a half-street along Mountainview Avenue and San Bernardino Avenue, adjacent to the project site, and install the required improvements in accordance with the notification and direction received from the City of Redlands.
- **LAND-2**: Submit and obtain approval for pipeline construction plans to the cities of Rancho Cucamonga, Fontana, Rialto, Colton, San Bernardino, Redlands, and county of San Bernardino.
- **LAND-3**: Provide a landscaping plan to the Energy Commission for approval and construct and maintain approved landscaping plan.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
SOCIOECONOMICS
Ellen LeFevre

INTRODUCTION

The proposed replacement of existing combustion turbine components with Advanced Gas Path upgraded components will require a peak of 150 workers. From a socioeconomics standpoint, the proposed amendment would have insignificant workforce-related impacts on housing and community services.

The Condition of Certification **SOCIO-1** in the March 2001 Energy Commission Decision would be applicable to the proposed amendment and staff proposes a modification to the verification of compliance with **SOCIO-1** to ensure the required documentation is provided to the CPM at least thirty days prior to the scheduled maintenance outage.

CONCLUSIONS AND RECOMMENDATIONS

The proposed amendment requests to replace certain internal components in the gas turbine hot gas path with Advanced Gas Path components on the four existing combustion turbines. The current installed hot gas path components are scheduled to be replaced during the planned major maintenance outage in late March 2016 and conclude in late April 2016 or early May 2016. The Mountainview facility is located in a predominantly commercial/industrial area of Redlands, California.

The workforce for the proposed modification is expected to reach a peak of approximately 150 workers. Approximately half of these individuals will be GE personnel and its contractors. The remaining individuals will consist of Southern California Edison Company staff and contractors to perform plant maintenance activities that are in addition to the turbine overhauls being performed by GE. Each day's work will involve two 12-hour shifts, each beginning and ending at 7:00 a.m. and 7:00 p.m. Existing parking areas within the plant will accommodate this workforce. The construction needs for the project modification would not affect the workforce of the Riverside-San Bernardino-Ontario Metropolitan Statistical Area (San Bernardino County).

The proposed amendment would not cause an impact under the California Environmental Quality Act Guidelines, Appendix G XIII, XIV, and XV.

The proposed Amendment would not affect the Socioeconomics Conditions of Certification **SOCIO-2** (school impact fees) in the March 2001 Energy Commission Decision, which is inapplicable to the amendment.

PROPOSED MODIFIED CONDITION

SOCIO-1 requires verification prior to the start of earth moving activities, while the proposed modification would not require any ground disturbing activities. Staff is proposing modifications to **SOCIO-1**, as identified below.

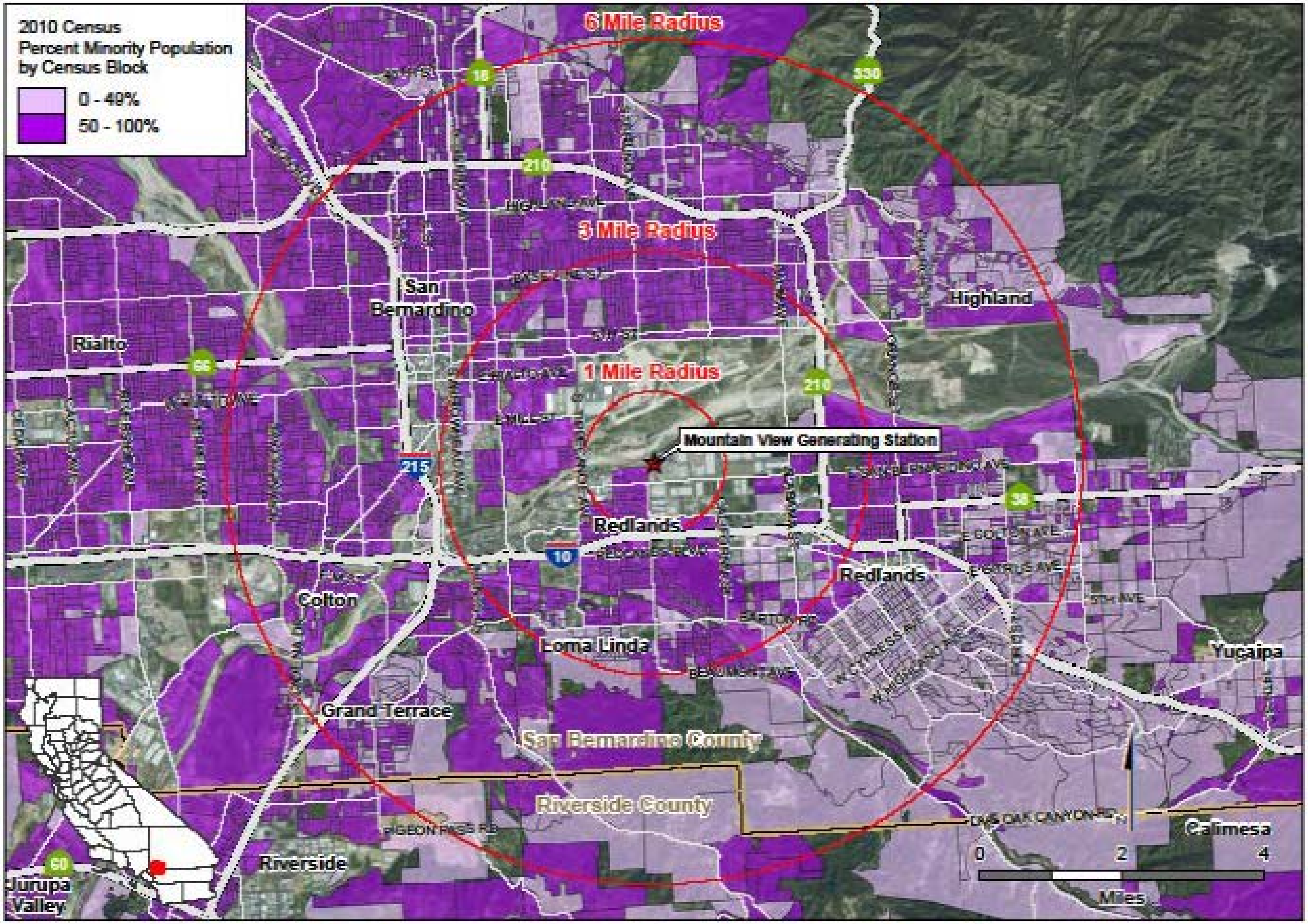
Condition of Certification **SOCIO-1** would be applicable to the proposed amendment. **SOCIO-1** states:

> The project owner and its contractors and subcontractors shall recruit employees and procure materials and supplies from within San Bernardino, Riverside, Los Angeles, and Orange Counties, and encourage such recruitment and purchases within the local vicinity of the proposed project area first unless:
>
> - To do so will violate federal and/or state statutes;
> - The materials and/or supplies are not available; or
> - Qualified employees for specific jobs or positions are not available; or,
> - There is a reasonable basis to hire someone for a specific position from outside the local area.
>
> **Verification:** ~~At least sixty (60) days prior to the start of earth moving activities,~~ **At least thirty (30) days prior to the scheduled major maintenance outage**, the project owner shall submit to the Energy Commission Compliance Project Manager (CPM) copies of contractor, subcontractor, and vendor solicitations and guidelines stating hiring and procurement requirements and procedures. In addition, the project owner shall notify the CPM in each Monthly Compliance Report of the reasons for any planned procurement of materials or hiring outside the local regional area that will occur during the next two months.

The proposed Amendment would have no significant on workforce-related impacts on housing and community services. In addition, the project modification would not affect any population including the Environmental Justice population as shown in the Environmental Justice Population Figure and Table.

ENVIRONMENTAL JUSTICE POPULATION

Mountain View Generating Station - Census 2010 Minority Population by Census Block



CALIFORNIA ENERGY COMMISSION - SITING, TRANSMISSION AND ENVIRONMENTAL PROTECTION DIVISION

SOURCE: Census 2010 PL 94-171 Data

Minority Populations

The Environmental Justice Population Figure shows census blocks in the potentially affected area with a minority population greater than or equal to 50 percent. The population in these census blocks represents an environmental justice population as defined by Environmental Justice: Guidance Under the National Environmental Policy Act.

Below-Poverty-Level Populations

The Council of Environmental Quality and the US Environmental Protection Agency guidance documents identify a 50-percent threshold to determine whether minority populations are considered environmental justice populations, but do not provide a discrete threshold for below-poverty-level populations. To better understand the presence of poverty in the area and determine whether a low-income population of sufficient size is present, staff looks at the below-poverty-level populations in the cities within the six-mile radius and compares them to other appropriate reference geographies, such as the county, state, or County Census Divisions (CCD).

Staff used the cities of Colton, Grand Terrace, Highland, Loma Linda, Redlands, and San Bernardino to represent the population in a six-mile radius of the project site. Staff used San Bernardino County and California as the reference geographies. The data in the Environmental Justice Population Table shows the percentage of population living below the federal poverty level in the cities in a six-mile radius of the project site and the reference geographies. Staff concluded that the percent of population living below the federal poverty line in the cities of Colton and San Bernardino are meaningfully greater than the below-poverty-level population in the reference geographies and would constitute an environmental justice population as defined by Environmental Justice: Guidance Under the National Environmental Policy Act.

Environmental Justice Population Table-
Poverty Data within the Project Area

	Total Population1			Population Below Poverty Level			Percent Below Poverty Level		
	Estimate	MOE 2	CV3 (%)	Estimate	MOE	CV (%)	Estimate	MOE	CV (%)
CITIES IN SIX-MILE RADIUS4									
Colton	52,745	±177	0.20	12,314	±1,719	8.49	23.30	±3.3	8.61
Highland	53,695	±178	0.20	10,875	±1,288	7.20	20.30	±2.4	7.19
Loma Linda	23,073	±204	0.54	4,081	±880	13.11	17.70	±3.8	13.05
Redlands	67,247	±395	0.36	9,735	±1,271	7.94	14.50	±1.9	7.97
San Bernardino	206,995	±658	01.9	68,257	±2,962	2.64	33.00	±1.4	2.58
REFERENCE GEOGRAPHIES									
San Bernardino County	2,029,255	±2,985	0.09	389,037	±8,542	1.33	19.20	±0.4	1.27
California	37,323,127	±3,616	0.01	6,115,244	±38,636	0.38	16.40	±0.1	0.37

Notes: 1 Population for whom poverty is determined. 2 Margin of Error. 3 Coefficient of Variation (method of evaluating the reliability of the estimates. US Census staff recommends caution when interpreting estimates with more than 15 percent CV. 4 Data for the city of Grand Terrace is not presented as the CV is well over 15 percent. Source: U.S. Census Bureau 2010-2014 Five-Year American Community Survey Estimates.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
VISUAL RESOURCES
JIM ADAMS

INTRODUCTION

The proposed replacement of certain internal components in the gas turbine hot gas path would not be visible and there would be no significant visual impacts.

CONCLUSIONS AND RECOMMENDATIONS

The proposed amendment requests to replace certain internal combustion turbine components with Advanced Gas Path (AGP) components on the four existing combustion turbines. Modifications to the combustion turbine internal components would not be visible and there would be no change in the physical appearance of the MGS. The modifications do not require the construction of new equipment or lay-down staging areas. Viewers in the local primarily commercial/industrial area are used to traffic in and out of the plant during regularly scheduled major maintenance component replacement activities.

Conditions of Certification **VIS-1** (treatment of project structures), **VIS-2** (project fencing), **VIS-3** (shielded lighting), and **VIS-4** (Santa Ana River Trail visual screening) identified in the Commission Decision (March 2001) in the MGS proceeding would not apply to the proposed modification.

The proposed amendment would have no significant visual impacts. In addition, the project modification would not affect any population including the Environmental Justice population as shown in the Environmental Justice Population Figure.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
WASTE MANAGEMENT
Ellen Townsend-Hough

INTRODUCTION

On January 11, 2016, the Southern California Edison Company (SCE), the owner of the Mountainview Generating Station (Mountainview), filed a petition with the California Energy Commission (Energy Commission) requesting to amend the March 22, 2001 Final Decision for Mountainview. The 1,056-megawatt project was certified on March 21, 2001, and began commercial operation on January 19, 2006. The facility is located in the city of Redlands, in San Bernardino County.

SCOPE OF ANALYSIS

SCE proposes to replace certain existing combustion turbine components with Advanced Gas Path upgraded components at Mountainview. These replacement components will improve combustion turbine heat rate, increase generator ramp rate, reduce the generator minimum-load operating point, and increase Mountainview's rated MW output by about 48 MW.

The scope of this analysis is to determine whether the replacement of existing combustion turbine components with Advanced Gas Path upgraded components would result in waste management impacts. Where impacts may occur staff has identified whether existing conditions of certification in the current license would address the impacts. Where new impacts not analyzed in the original project license are identified, staff will conduct the necessary analysis to determine whether a change, addition, deletion, or new condition of certification would be necessary The evaluation of the proposed project and the mitigation measures are intended to reduce the risks and environmental impacts associated with handling, storing and disposing of waste.

ANALYSIS OF IMPACTS

During construction and maintenance, the waste produced would include but is not limited to: excess packing materials, basic building materials and empty containers. The hazardous materials generated during construction would include dried paint and possibly trace amounts of hazardous waste in miscellaneous building materials. The project would be replacing hot gas path components during the upcoming outage – staff does not expect the upgrade to Advanced Gas Path components to generate more waste during operation. Approved Condition of Certification **WASTE- 4** would apply to the proposed petition. **WASTE- 4** requires that waste generated during construction is tracked and disposed at the proper facilities. The project owner should be required to comply with this condition of certification for the proposed construction activities.

CONCLUSIONS AND RECOMMENDATIONS

Staff concludes that the replace certain existing combustion turbine components with Advanced Gas Path upgraded components at Mountainview would not result in any additional environmental impacts in terms of waste management in comparison with the original analysis and normal maintenance for the approved project and subsequent approved amendment provided the project owner complies with **WASTE-4**. The proposed activities would not result in a change or deletion of a condition adopted by the commission or make changes that would cause the project not to comply with any applicable laws, ordinances, regulations, or standards.

PROPOSED CHANGES OR MODIFICATION TO CONDITIONS OF CERTIFICATION

Staff is not proposing any changes or modifications to conditions of certification. The existing conditions of certification are adequate to ensure there would be no unmitigated significant impacts.

REFERENCES

SCE 2016—PG&E (tn: 207273), Mountainview Generating Station Petition To Amend The Commission Decision For Hot Gas Path Component Replacement, (00-AFC-02C), January 11, 2016.

MOUTAINVIEW GENERATING STATION (00-AFC-02C)
Petition to Amend Commission Decision
WORKER SAFETY/FIRE PROTECTION
BRETT FOOKS

INTRODUCTION

The replacement of certain internal components in the gas turbine hot gas path would not have a significant effect on power plant worker safety or fire protection.

CONCLUSIONS AND RECOMMENDATIONS

By continuing to comply with the existing conditions of certification, the petitioner's proposed installation of advanced combustion components for the existing turbines would not have a significant impact on the off-site public or the environment, and would continue to comply with all applicable LORS. The installation of advanced combustion components would include replacement of the turbine blades, nozzles, and associated structural elements. Activities to be performed during the installation would comply with the worker safety and fire protection requirements already contained in the facility's existing health and safety plans utilized for construction of the main facility per Condition of Certification **WORKER SAFETY-1**.