DOCKETED

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Project Title:	Elmore North Geothermal Project (ENGP)
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Document Title:	Preliminary Decision of Compliance (POC) Elmore North
Description:	Imperial County APCD PDOC for the geothermal power generation facility Elmore North, APCD Permit #4711 District Review
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January 2024

IMPERIAL COUNTY AIR POLLUTION CONTROL DISTRICT
Preliminary Determination of Compliance

Permit No.:	4711
Source Name:	Elmore North Geothermal, LLC
Source Type:	Geothermal Power Generation
Applied for:	District Review
Mailing Address:	7030 Gentry Rd. Calipatria, CA 92233
Project Location:	APN 020-100-038 bounded by Sinclair Road, Cox Road, and Garst Road
Responsible Person:	Jon Trujillo General Manager Phone: (760) 604-0045
Person in Charge at Location	Anoop Sukumaran Phone: (760) 348-4275
Permit Reviewer:	Victor Mendez, APCD Engineer

Introduction

Elmore North Geothermal, LLC (the Applicant) is applying for an Authority to Construction/Permit to Operate (ATC/PTO) from the Imperial County Air Pollution Control District (ICAPCD or "Air District") for the proposed Elmore North Geothermal Project (ENGP) to be located at APN 020-100-038 bounded by Sinclair Road, Cox Road, and Garst Road. The Applicant has also submitted an Application for Certification (AFC) to the California Energy Commission (CEC). The purpose of the ENGP is to provide power from a renewable geothermal source in order to meet the electric power needs of California. The proposed project has a design rating of approximately 157 megawatts (MW) of gross output, with an expected net output of approximately 140 MW. ICAPCD has reviewed the application submitted by the Applicant and this document serves at the Air District's Preliminary Determination of Compliance (PDOC).

Facility Description

Facility Overview

The ENGP will be located on a 63-acre parcel of land in Imperial County that is north of the existing J.J. Elmore geothermal power plant and southeast of the Salton Sea. The ENGP will be comprised of a geothermal resource production facility, a geothermal powered power generation facility, and associated ancillary facilities. The resource production facility will include geothermal production and injection wells, pipelines, fluid and steam handling facilities, a solid handling system, Class II surface impoundment, a service water pond, a retention basin, process injection pumps, and steam polishing equipment. The power generation facility will include a triple pressure condensing turbine/generator set, surface condensers, a non-condensable gas (NCG) removal system, a heat rejection system, a generator step-up transformer (230-kilovolt substation) and power distribution centers. The ENGP's geothermal resource production facility and geothermal powered power generation facility will share a control building, service water pond, and other secondary support facilities. The ENGP will have an expected net output of approximately 140 MW.

The geothermal brine in the Salton Sea Known Geothermal Resource Area exists at temperatures greater than 500 degrees Fahrenheit within the subsurface reservoir. Geothermal fluid will be produced from nine production wells around the power plant. The fluid will flow to the steam handling system next to the power generation facility through aboveground pipelines. The fluid will then be separated from the steam phase to produce high-pressure steam. After the high-pressure steam is produced, the remaining geothermal fluids will be flashed at lower pressures to produce standard-pressure and low-pressure steam for the steam turbine. Dilution water will be added to the low-pressure crystallizer to control precipitation. Next, an atmospheric flash tank will be used to ensure the fluid has no residual pressure before flowing into the primary and secondary clarifiers. The clarifiers will be used to remove suspended solids produced at the resource production facility. Solids precipitation will be a necessary step within the process to transform the geothermal fluid from a supersaturated state to chemical equilibrium to facilitate sustainable injection. The spent geothermal fluid will be returned to the underground reservoir using different injection wells for the three fluid types: spent geothermal fluid, aerated geothermal fluid, and condensate. The aerated fluid will be produced from the resource production facility impoundment, and the condensate will be discharged from the cooling tower. Mixing the fluids could result in scaling and excess precipitation which risks sustainable injection of the fluids into the reservoir.

The steam from the resource production facility will be transported to a triple condensing steam turbine after the impurities are removed. The steam will exit the turbine and enter the surface condensers. The condensed steam will be used as cooling tower makeup water, and the NCG will be extracted from the main condensers by the gas removal system. The extracted NCG will be transported to the cooling tower basin through gas distribution sparger pipes near the bottom of the cooling tower basin for hydrogen sulfide (H_2S) abatement using an oxidizing biocide process (BIOX). The electricity generated from the project will be transported to an onsite substation in the northeast region of the site where the electrical energy will be delivered to a new Imperial Irrigation District (IID) switching station using a short interconnection transmission (gen-tie) line.

Project Description

The primary objective of the ENGP is to develop, construct, and operate a renewable electrical generating facility to support the state of California's transition to renewable energy and support grid reliability.

Resource Production Facility

The resource production facility will include two types of wells: production wells and injection wells. The production wells will be used to extract geothermal fluid, and after the heat and steam from the geothermal fluid is used for power generation, the injection wells will be used to return the spent geothermal fluid to the reservoir. The equipment associated with the resource production facility is listed in the Equipment List section of this document.

Production Wells and Pipelines

Nine production wells will be located on five new well pads which will be located adjacent, west, and north of the facility. Aboveground pipelines will connect the well pads to the resource production facility. There will be a production warmup pipeline for each well pad which will be used to start up wells during facility startup. The warmup pipeline will discharge into the atmospheric flash tank and then into the Class II surface impoundment during initial startup.

During normal facility operation, the production fluids will travel through the production pipelines to the high-pressure separator. Each production well will have an average production capacity of 1,626,000 pounds per hour, but assuming all wells are in service, each well will only produce approximately 1.1 million pounds per hour of the steam, NCG, and geothermal fluid mixture needed to satisfy the overall production demand of 10,294,000 total pounds per hour. The produced fluid is anticipated to be approximately 27.9% total dissolved solids (TDS) and 0.053% NCG at reservoir conditions with a total enthalpy of 393 Btu per pound.

Fluid/Steam Handling System

The high-pressure separator system will be used to separate the two-phase production fluid as it enters the power plant from the production wells and will produce high-pressure steam that is discharged into a pipeline to the high-pressure scrubber and demister before entering the steam turbine. The remaining fluid will continue to the standard-pressure crystallizers. To minimize the adhesion of the iron-silicate scale to the walls of the vessels, pipelines, and tanks, the pressure vessels will be injected with iron-silicate-laden slurry from the underflow of the primary clarifier. The crystallizers will also separate the standard-pressure steam from the fluid so the steam can be discharged through the pipelines to the standard-pressure scrubber and demister before entering the steam turbine. Similar to the standard-pressure crystallizer system, the low-pressure crystallizer system will stabilize the fluid and separate the steam from the fluid for further processes, but the process will occur at a lower pressure and temperature. The chlorides within the fluid will be stabilized with the addition of heated dilution water to maintain a total dissolved solids concentration of less than 32%, whereas the chloride salts will begin to precipitate within the process if the total dissolved solids exceed approximately 32%. .

Then, the geothermal fluid will flow to the atmospheric flash tank from the low-pressure crystallizer system. The fluid pressure will be lowered to atmospheric pressure conditions by the atmospheric flash system before flowing to the primary clarifier via gravity. The steam from the atmospheric flash tank will be discharged to the dilution water heaters while the excess will be vented to the atmosphere. The dilution water heaters will preheat and de-aerate the water from the service water storage pond before diluting it with the low-pressure crystallizers. The de-aeration process will remove detrimental oxygen from the water prior to entering the low-pressure crystallizers. The dilution water heater will be a spray type barometric counterflow de-aerator that uses steam from the flashed spent fluid from the atmospheric flash tank.

Afterwards the heat-depleted fluid will be directed to the fluid clarification system for solids separation and removal. The fluid clarification system will consist of one primary clarifier and one secondary clarifier. Within the clarifiers, flocculation will help to settle iron silicate solids through agglomeration. A rake will rotate inside the tank to keep the settled particles moving towards the underflow and launders allow the fluid to overflow from the primary clarifier into the secondary clarifier for further removal of solids. The slurry from the underflow in the primary clarifier will be transported upstream and used as seed material while the rest will travel to the solids dewatering system. The secondary clarifier will function similarly to the primary clarifier with the rake, underflow, and overflow. Upon leaving the secondary clarifier, the underflow slurry will be passed back to the primary clarifier for further amalgamation while the clarified fluids overflow and return to the injection wells to be injected back into the reservoir. The clarifiers will be used to prevent solids in the geothermal fluid from clogging the wells, and they will be covered with steam to prevent oxygen intrusion and designed to prevent corrosion. The clarifiers will also be equipped with emergency overflow that will be routed to the Class II surface impoundment.

Solids Dewatering

As described above, part of the slurry from the underflow of the primary clarifier will be transported to the solids dewatering system. There will be two stages in the solid removal process. The primary process will include removal in the form of slurry, and the secondary process will include dewatering of the slurry. The dewatered solids will be transported to end-dump trailers via a covered conveyor belt. Once filled, the trailers will be covered to minimize fugitive dust emissions and as a waste management best practice. The full trailers will remain at the facility for approximately five days to confirm the filter cake will be nonhazardous through the Total Threshold Limit Concentration (TTLC) and Soluble Threshold Limit Concentration (STLC) analysis of the filter cake. If the filter cake is determined to be hazardous, it will be disposed of in the necessary manner, and if it is nonhazardous, the filter cake will be disposed of at a Class II regulated landfill.

Fluids from the Class II surface impoundment and other similar aerated fluids will be directed to the thickener or similar solids separation equipment. The purpose of the thickener will be to receive oxygenated fluids from the geothermal process and keep them separate from the primary geothermal process fluids to prevent excess solids, scaling, and corrosion. The fluids will exit the thickener and be transported to an aerated fluid injection well, while the slurry will exit the thickener and be transported to the solids dewatering system.

Fluid Injection System

After the spent geothermal fluid exits the secondary clarifier, it will be transferred from the resource production facility to the injection wells via aboveground pipelines. The eleven injection wells will be located on six different injection well pads south of the resource production facility.[1] Eight of the wells will be used for injection of the spent geothermal fluid received from the secondary clarifier, two well will be used for the condensate injection, and one well will be used for aerated fluid injection. Each well will be drilled using directional drilling technology to be approximately 7,500 feet deep. The injection pumping system will include a local control panel and will be monitored remotely from the control room, but the main control will be within a motor control center at the local power distribution and control system.

At the southern border of the project site, the injection fluid pipeline will exit the site and travel to the new injection wells. A 50 foot right of way will be required for the construction of the pipelines. Each right of way will contain one or more pipelines for spent geothermal fluid which will be installed on supports and elevated above grade.

The Class II surface impoundment (brine pond) will be a concrete-surfaced basin large enough to hold the partial draining of both clarifiers and two feet of freeboard. The impoundment will be triple-lined and include a Leachate Collection and Removal System that can detect leaks within the primary liner. The Leachate Collection and Removal System will also have an automated pump collection system designed to overflow into the Class II surface impoundment and discharge into a containment system.

The fluid injection system brine pond will be located near the clarifiers. During upset conditions, after the spent geothermal fluid from the clarifiers and thickener are transported to the brine pond for storage, the fluid will be pumped to the aerated geothermal injection well. The brine pond will be used to temporarily store the spent geothermal fluid, solids that have precipitated out of the fluid during power generation, as well as fluids generated from emergency situations, maintenance, hydro blasting, safety showers, eye wash stations, vehicle wash stations, plant conveyor systems, and reject water from reverse osmosis. After drilling maintenance and startup, the brine pond will collect the geothermal fluids during flow testing and then discharge the fluid to an injection well after startup.

Power Generation Facility

The high-pressure, standard-pressure, and low-pressure steam produced in the resource production facility will travel to the power generation facility to power the turbine generator system and produce electricity. The power generation facility will consist of the triple pressure condensing turbine/generator set, surface condensers, NCG removal system, a sparger abatement system, condensate bio-oxidation abatement systems in the cooling tower system, a heat rejection system, and a generator step-up transformer. The equipment associated with the power generation facility is listed in the Equipment List section of this document.

Turbine Generator System

The turbine generator system will consist of the high-, standard-, and low-pressure steam entries and a 3,600 revolutions per minute (rpm), triple-pressure, quad-exhaust flow condensing turbine. The turbine will have a maximum continuous rating of 157 MW gross (140 net MW). The normal inlet pressure for the high-pressure entry will be approximately 305 pounds per square inch gauge (psig),

[1] In a letter submitted on November 14, 2023, the Applicant clarified that the number of injection wells has been decreased from twelve (12) to eleven (11). As stated by the Applicant, the emission estimates, air quality impact analysis, and health risk assessment submitted on November 10, 2023, which were based on twelve (12) injection wells, are considered to be conservative and representative of the updated ENGP design.

the normal inlet pressure for the standard-pressure entry will be approximately 122 psig, and the normal inlet pressure for the low-pressure entry will be approximately 15 psig. A completely enclosed water and air-cooled synchronous generator will be directly coupled to the turbine. At a power factor of 0.85 lagging and leading, the generator will be expected to have a design rating of 174,000 megavolt-amperes. The turbine-generator system will be equipped with all necessary auxiliary systems for turbine control and speed protection, lubricating oil, gland sealing, generator excitation, and cooling.

Heat Rejection System

The power cycle heat rejection system will be comprised of a shell-and-tube type condenser constructed of stainless-steel or a similar material, a 14-cell counterflow cooling tower, a NCG removal system, and a hydrogen sulfide abatement system. When steam exits the turbine exhaust, it will be condensed by the shell-and-tube type condenser. The condensate will then be transported to the biological oxidizer unit next to the cooling tower via stainless steel piping. At the biological oxidizer, the hydrogen sulfide will be abated. The gas removal system, which will be made up of multiple redundant trains of ejectors and liquid ring vacuum pumps, will remove the gases that accumulate in the condenser, and the gases will be conveyed to the spargers in the cooling tower basin. The standard-pressure pipeline will provide the auxiliary steam for the ejectors.

Cooling Tower

The circulating water will be cooled by a cooling tower that will consist of fourteen cell units and 480-volt motor driven fans. Each of the fourteen cells will be separated from one another to allow for maintenance to be completed during normal operation. The cooling tower basin will be equipped with vertical wet-pit circulating pumps that circulate the water between the turbine condensers and cooling tower. The cooling tower will also be equipped with vertical, wet-pit auxiliary water pumps which will move water between the plant auxiliary cooling loads and the cooling tower. The plant auxiliary loads will consist of the generator cooling system, NCG removal system, turbine lubricating oil, and control oil cooling system, and solids dewatering system. The cooling tower will be equipped with high efficiency cellular type drift eliminators designed to limit drift losses to at or below 0.0005% of the recirculation rate.

Facility Support System

The facility support systems are the ancillary facilities and equipment that will be required for the resource production facility and the power generation facility to operate successfully. The support systems include yard tanks, fire protection and safety systems, emergency equipment, emissions control equipment and other systems required for the maintenance of equipment and powering the general building operations such as heating, cooling, plumbing, and lighting.

Yard Tanks

The major yard tanks included in the ENGP will be a condensate storage tank, thickener tank, thickener and aerated fluid injection tank, excess condensate storage tank, diesel fuel tank, and various chemical holding tanks, including one 20,000-gallon hydrochloric acid tank. The yard tanks will be vertical, steel or manufactured approved fiberglass-reinforced plastic (FRP) tanks that will sit on a foundation of either a reinforced concrete ring wall with an interior bearing layer of compacted sand or a reinforced concrete mat. Both the reinforced concrete ring wall supports, and the reinforced concrete mat foundation may require piles. The internal and external coatings and/or materials of the tanks will be protected from corrosion as needed.

Emergency Standby Diesel-Fueled Engines

The ENGP will include three Tier 4 standby diesel engine driven emergency generators and one Tier 3 diesel-fueled fire water pump. The emergency generators will have a maximum power rating of 3.25 MW. The generators will provide emergency electrical power for plant critical loads in the event of a total loss of auxiliary power or if the utility system is out of service. The generators will be sized to maintain operation of fluid booster pumps, the air compressor, the turbine turning gear, emergency lighting, heating, ventilation and air conditioning (HVAC), injection pumps, and other vital loads.

The fire protection system will include electric fire water pumps and an emergency standby diesel-fueled fire water pump with a maximum output of 236 kilowatts. The fire protection systems will be enclosed in a pump house that will include a sprinkler system, louvered engine heaters, lights, exhaust fans, and an electrical distribution panel. The service water pond capacity will include fire water storage to ensure there is an adequate amount of water available for fire protection.

Abatement Equipment

The primary source of criteria pollutant emissions from the proposed project will be particulate matter from the project's cooling tower. As discussed previously, the cooling tower will be equipped with high efficiency cellular type drift eliminators with a drift rate of 0.0005%. Controlling the drift losses combined with minimizing the total dissolved solids concentration in the circulating water will minimize the particulate matter emissions from the cooling tower.

Low concentrations of hydrogen sulfide will be present in the NCG and condensate produced in the main condenser. The proposed project will include a bio-oxidation box (Ox-Box), which will be located adjacent to the cooling tower to control the H_2S emissions from the main condenser. The Ox-Box will include a trickle block, splash fill, or equivalent packing that will mix the water from the cooling tower with the condensate from the main condenser. The Ox-Box will drain into the cooling tower basin and the H_2S emissions will be measured at the discharge of each cell in the cooling tower to ensure compliance.

The Ox-Box will operate as a bio-trickling filter, with the sour condensate trickling down the packing which will be fouled with several species of sulfur bacteria and denitrifying bacteria. The species of bacteria will oxidize the H_2S into elemental sulfur, and subsequently into sulfates.

The abatement system will also include a Sparger System, which will utilize BIOX, comprised of distribution pipes with bubble diffusers/nozzles. The off-gas containing H_2S from the condenser will be transported and bubbled through the Sparger System to the bottom of the cooling tower basin. The H_2S contained in the off-gas will be dissolved in the cooling tower water and converted to sulfate by reacting with the BIOX and the dissolved oxygen in the water. The sparger and Ox-Box system will have a combined minimum control efficiency of 98.5%.

There will also be a hydrochloric acid (HCl) storage tank and associated scrubber onsite. The scrubber will operate during tank loading operations to control vapor displacement during filling. These operations are estimated to occur for 8,760 hours per year.

Power Generation Operating Scenarios

The power generation facility included in the ENGP will release steam-related emissions through one or more sources depending on the operation scenario. Sources of emissions will include a mobile testing unit that will be deployed during commissioning at each well head, two production testing units which will be located on top of the two warm-up atmospheric flash tanks, a rock muffler, an HCl scrubber, three 3.25 MW diesel-fired emergency generators, one diesel fire water pump, and the fourteen cooling tower cells. Throughout a typical year, the facility may operate in one of multiple operating scenarios. The potential operating scenarios include commissioning, which will only occur during the first year of production, cold startup, warm startup, shutdown, flowback and testing activities, and routine power generation operations with or without emission control downtime. A summary of each operating condition and the applicant's estimated annual hours of operation for each process within the scenario are described below.

A. Commissioning – Commissioning is an operating scenario for the power generation facility that will occur during the first production year. The overall project schedule for construction and commissioning of the ENGP is expected to take 29 months. During this scenario, the hours of operation for commissioning activities will differ in comparison to the routine power generation scenario. The well warm-up will be 216 hours per year, the production line and equipment warm-up will be 48 hours per year, the steam blow will be 240 hours, the turbine preheat and auxiliary loop will be 48 hours per year, the turbine load test will be 72 hours per year, and the turbine performance test will be 48 hours per year. Commissioning activities are included in the facility-wide potential-to-emit (PTE) to conservatively capture the worst-case air quality scenario.

B. Cold Startup – Cold startup will occur when the facility has been completely shut down and all fluid flow to plant has been isolated for an extended period. The annual hours of operation for cold startup sequences will be the same for the first production year, and all subsequent years. During a production year with cold startup, the well warm-up will be 120 hours per year, the production line and equipment warm-up will be 32 hours per year, the turbine preheat and auxiliary loop will be 24 hours per year, the auxiliary equipment startup will be 12 hours per year, the functional trip test will be 6 hours per year, and the gradual steam delivery to turbine will be 6 hours per year.

C. Warm Startup – Warm startup will occur when the turbine has been offline, but the resource production facility is still operational. Warm startups can take up to 10 hours. The annual hours of operation for warm startup sequences will be the same for the first production year, and all subsequent years. During a production year with warm startup, the geothermal steam sent the rock muffler is estimated to occur for up to 200 hours per year, and the gradual diversion of steam from the rock muffler to the turbine would occur up to 100 hours per year.

D. Facility Shutdown – Temporary facility closures can result from a variety of circumstances. Depending on the length of the shutdown, chemicals may be drained from the storage tanks to other equipment and disposed of in accordance with the laws and regulations for the material at the time of closure. The annual hours of operation for shutdown will be the same for the first production year, and all subsequent years. During a production year with a shutdown, the facility will not operate for 198 hours per year.

E. Flow Back and Well Testing Activities – Well flowback activity will occur during the first year of production and may occur in subsequent years. Well testing will only occur in the first production year. During the first production year, production well testing will be 2,160 hours per year (240 hours per well and 9 production wells total) and injection well testing will be 2,880 hours per year (240 hours per well and 12 injection wells total[2]). During the first year and any subsequent years, production well flowback will be 216 hours per year, and injection well flowback will be 288 hours per year.

F. Routine Power Generation Operation – In a production year without startups, shutdowns, or emission control downtime, the power generating facility will operate with controls for the full 8,760 hours of the year. For the first production year, the power generating facility will operate with controls for an estimated 1,346 hours per year, with sparger bypass/breakdown for an estimated 200 hours per year, and with Ox-Box bypass/breakdown for an estimated 200 hours per year. In any subsequent production years with startups, shutdowns, and emission control down time, the power generation facility will operate with all controls for 7,058 hours per year, with sparger bypass/breakdown for 200 hours per year, and with Ox-Box bypass/breakdown for 200 hours per year.

[2] Although the ENGP will include only eleven (11) injection wells, the hours presented here and utilized in the emission estimates and associated modeling are considered conservative and representative as they are based on twelve (12) injection wells.

Emissions Calculations

Pollutants

Operation of the proposed ENGP will result in emissions to the atmosphere of hydrogen sulfide (H_2S), as well as criteria air pollutants (CAPs), toxic air contaminants (TACs), and greenhouse gases (GHGs). CAP emissions will consist primarily of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), sulfur oxides (SO_X), particulate matter smaller than 10 microns in diameter (PM_{10}), particulate matter smaller than 2.5 microns in diameter ($PM_{2.5}$), and lead. GHG emissions may include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). TACs will consist of a combination of toxic gases and toxic particulate matter species.

Emissions Sources, Control Technology, and Calculation Methodology Overview

A. Steam and NCG-Related Processes – Emissions were estimated based upon analytical data from other geothermal power plants in the area (Elmore Geothermal Plant ["Elmore"] and Leathers Geothermal Facility ["Leathers"]). The analytical data used in the analysis consists of a speciated breakdown of concentrations from a NCG sample, and system inlet and outlet operations from the geothermal system's geothermal steam flows. The Project's geothermal steam flows vary in pressure and are categorized as high-, standard-, and low-pressure, each of which has an assumed NCG concentration. The NCG and system inlet/outlet analytical data are applied to production well estimated steam flows for the ENGP to determine a total mass of species through the geothermal system. During processing and condensing of the geothermal steam, a portion of the species remain in gas phase and are routed through the sparger installed inside the cooling tower basin; the remaining condensed liquid portion of the species are routed through the Ox-Box and then overflows to the cooling tower. The mass throughputs of these species are used in conjunction with estimated control efficiencies and process-specific correction factors to estimate emissions. The methodology is applied to emissions of CAPs, TACs, and GHGs.

B. Cooling Tower – Emissions were estimated for two different streams: condensate/liquid within the cooling tower and the NCG vented from the power generation facility. The cooling tower for ENGP would be designed to have a 0.0005% drift eliminator. Additionally, ENGP would utilize an H_2S treatment system consisting of a sparger and Ox-Box to remove H_2S. The proposed sparger system and Ox-Box are expected to operate with a combined minimum control efficiency of 98.5%.

   a. Gas Phase Emissions – The NCG stream was characterized using analytical data from other geothermal power plants in the area (Elmore and Leathers). All constituents except mercury, arsenic, and hydrogen sulfide (H_2S) are assumed to directly pass through in the gas phase as emissions on a mass basis.

   b. Condensate/Liquid Phase Emissions – Liquid-based emissions are the result of NCG condensate and make-up water input into the cooling tower for circulation.

      i. Particulate Matter Emissions – Emissions from the circulating water were estimated using an assumed maximum total dissolved solids (TDS) concentration from analytical testing conducted at other Applicant-owned facilities in the region and an assumed drift loss.

ii. TAC and VOC Emissions – With the exception of ammonia, TAC and VOC emissions were calculated using the cooling tower circulating water and makeup water flow rates. Specifically, VOC emissions were estimated by applying hot well analytical data from other geothermal power plants in the area to the ENGP's estimated hot well flow rates. 100% of the VOC emissions in the hot well condensate are assumed to be emitted through the cooling tower. Non-volatile TAC emissions were estimated by applying blowdown analytical data from other geothermal power plants in the area to the Project's cooling tower circulating water flow rates and emitted in the form of drift losses. These emissions include mercury and arsenic originating in the steam, which are expected to cool into either liquid or solid form and remain in the cooling tower basin.

iii. Ammonia Emissions – Emissions from the liquid portion of the cooling tower were calculated assuming a mass balance between the ammonia entering the cooling tower (in the form of hot well condensate) and leaving the cooling tower (in the form of blowdown). Specifically, hot well and blowdown analytical data from other geothermal power plants in the area were used with Project-specific hot well and blowdown flow rates to determine the amount of ammonia remaining in the cooling tower after blowdown, which is assumed to be emitted through the cooling tower shrouds.

c. H_2S Emissions – H_2S emissions from the NCG stream are assumed to split between the gas phase and the condensate/liquid phase prior to reaching the cooling tower at a ratio of 60 to 40%, respectively (based on average source test results from Elmore). Thus, 60% of the total mass flow of H_2S in the steam is incorporated into the gas phase emissions calculations described above, while 40% is incorporated into the liquid/condensate calculations.

C. Diesel Fire Pump – CAP emissions from the diesel fire pump engine were estimated based upon vendor-provided data for a Tier 3-certified unit, with the exception of SO_2. SO_2 emissions were estimated based upon a mass balance wherein all sulfur in the fuel (assumed as ultra-low sulfur diesel) is assumed to be emitted as SO_2. GHG emissions from the engine were calculated consistent with 40 CFR Part 98 methodology. TAC emissions were estimated using emission factors from USEPA's AP-42 methodology.[3]

D. Diesel-fired Emergency Generators – CAP emissions from the three diesel-fired emergency generators were estimated based upon vendor-provided data, with the exception of SO_2. SO_2 emissions were estimated based upon a mass balance wherein all sulfur in the fuel (assumed as ultra-low sulfur diesel) is assumed to be emitted as SO_2. GHG emissions from the generators were calculated consistent with 40 CFR Part 98 methodology. TAC emissions were estimated based upon AP-42 methodology.[4] The vendor-provided data indicate that the engines will be

[3] United States Environmental Protection Agency. 1996. AP-42. 3.3: Gasoline and Diesel Industrial Engines. October.
[4] United States Environmental Protection Agency. 1996. AP-42. 3.4: Large Stationary Diesel and All Stationary Dual-fuel Engines. October.

compliant with Tier-4 emission rates through the use of a selective catalytic reduction (SCR) control device, diesel particulate filter, and diesel oxidation catalyst. As such, TAC emissions were assumed to be controlled by up to 80%. The SCR is assumed to have an ammonia slip rate of 5 parts per million (ppm).

E. Insulating Gas Emissions – Sulfur hexafluoride (SF_6) will be used as an insulating gas in various equipment. Emissions of SF6 were estimated based upon California's Regulation for Reducing Greenhouse Gas Emissions from Gas-Insulated Equipment (California Code of Regulations [CCR], Title 17, Section 95353, Tables 4 and 5) for data years through 2034. Emissions were converted to carbon dioxide equivalent units (CO_2e) using a global warming potential (GWP) for SF_6 of 22,800.[5]

F. O&M Equipment – Emissions were estimated using construction equipment emission factors, horsepower, and load factors from the CalEEMod® User's Guide.

G. O&M Vehicles – Emissions from vehicle exhaust and idling were calculated using emission factors from EMFAC2021.

H. Storage Tank Emissions – Estimates for storage tank emissions were not included in the Applicant's original application but were provided by the Applicant to the Air District in subsequent data requests. Based on the types and quantities of the materials proposed to be stored in the tanks, the Air District was able to confirm that the tanks are exempt from permitting requirements under Air District Rule 202.

I. HCl Scrubber – Estimates for emissions from the HCl scrubber associated with the bulk concentrated HCl storage tank were developed by the Applicant via a mass balance approach using Henry's Law and a conservative estimate that tank loading operations could occur 8,760 hours per year. The estimated emissions of HCl were provided in a submission to the Air District on November 10, 2023. No CAP emissions are anticipated to occur from this source.

Operational Schedule and Assumptions

Throughout a typical year, the ENGP facility may operate in one of the following operating conditions:

- Commissioning (only during the first production year)
- Flowback and Testing Activities
- Cold Startup
- Warm Startup
- Facility Shutdown
- Routine Power Generation Operation (with or without emission control downtime)

The ENGP steam-related emissions will be emitted through one or more sources, depending on the operating conditions of the power generation system. Emission points for this system include a mobile testing unit (MTU) that is temporarily deployed at each well head, two production testing units (PTU)

[5] 40 CFR Part 98, Table A-1.

which are located on top of two warm-up atmospheric flash tanks (AFTs) (one PTU per warm-up AFT), a rock muffler (RM), and the cooling tower cells (14 total).

A summary of each operating condition and the associated hours of operation is included in **Table 1**.

<table>
<tr><th colspan="5">Table 1. Facility Operating Hour Summary</th></tr>
<tr><th colspan="2">Project Operations</th><th>First Production Year
(hours)</th><th>Subsequent Production Years with Startups, Shutdowns and Emission Control Downtime
(hours)</th><th>Subsequent Production Years with Startups, Shutdowns and Emission Control Downtime
(hours)</th></tr>
<tr><td colspan="2">Production Well Flow Back</td><td>216</td><td>216</td><td>0</td></tr>
<tr><td colspan="2">Production Well Testing</td><td>2,160</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Injection Well Flow Back</td><td>288</td><td>288</td><td>0</td></tr>
<tr><td colspan="2">Injection Well Testing</td><td>2,880</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Commissioning</td><td>672</td><td>0</td><td>0</td></tr>
<tr><td colspan="2">Cold Startup</td><td>200</td><td>200</td><td>0</td></tr>
<tr><td colspan="2">Warm Startup</td><td>400</td><td>400</td><td>0</td></tr>
<tr><td colspan="2">Shutdowns</td><td>198</td><td>198</td><td>0</td></tr>
<tr><td rowspan="3">Routine Power Generation Operation</td><td>With Controls</td><td>1,346</td><td>7,058</td><td>8,760</td></tr>
<tr><td>Sparger Bypass/Breakdown</td><td>200</td><td>200</td><td>0</td></tr>
<tr><td>Ox-Box Bypass/Breakdown</td><td>200</td><td>200</td><td>0</td></tr>
<tr><td colspan="2">Total Operating Hours</td><td>8,760</td><td>8,760</td><td>8,760</td></tr>
</table>

The emissions calculations presented by the Applicant represent the highest potential emissions based on the proposed operating conditions. The hourly, daily, and annual emissions for all CAPs are based upon a series of worst-case assumptions for each pollutant. The maximum hourly emissions are based upon the worst-case hourly emissions expected from any source at the ENGP facility during any operating profile, considering both controlled and uncontrolled scenarios. The maximum daily emissions assume 24 hours of operation of the worst-case hourly emissions scenario with the exception of the fire pump and emergency generators. The fire pump and emergency generators are assumed to operate no more than one and two hours per day, respectively, for maintenance and testing purposes. Additionally, maintenance and testing operations of the emergency generators would be limited to no more than two units per day. With the exception of H_2S, emissions are based upon the highest emissions for each pollutant as derived from the operating scenarios presented above for both the first year of operation, including commissioning, and subsequent years of operation that do not include commissioning activities. For H_2S, only the worst-case subsequent year of operation was considered.

Example Calculations and Emissions Summary Tables

The example calculations below demonstrate how emissions were calculated for processes and equipment as part of the proposed project. Each calculation shows how the hourly and annual emission rates were derived based on analytical testing results from reference projects, proposed process flow rates, and proposed operational schedules. For demonstration purposes and unless otherwise specified, all calculations are shown specifically for H_2S emissions (for processes related to steam flow) or PM_{10} (for all other processes). Other pollutants for the same process were calculated similarly.

Maximum Emissions – Well Testing and Commissioning

Production Flowback: During flowback of the production wells, steam (including the NCG portion) flows to the MTU or PTU, where air emissions occur. These emission rates are dependent upon the concentration of the pollutant (for this example, 0.00845 pounds H_2S per pound of NCG), as well as the flow rate of the NCG (1,177 pounds per hour during flowback). The annual emission estimates are based on an anticipated 24 hours per flowback event each for a total of 9 production wells, once per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (1,177 lbs NCG/hr) = 9.95 lbs H_2S/hr
- Annual: (9.95 lbs H_2S/hr) x (24 hr/well) x (9 wells/event) x (1 event/yr) / (2,000 lb/ton) = 1.07 tons H_2S/yr

Production Well Testing: During testing of the production wells, steam flows to the MTU, where air emissions occur. Emission rates are dependent upon the concentration of the pollutants in the NCG, as well as the flow rate of the NCG (4,777 pounds per hour during testing). The annual emission estimates are based on an anticipated 240 hours per testing event each for a total of 9 wells, once per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (4,777 lbs NCG/hr) = 40.4 lbs H_2S/hr
- Annual: (40.4 lbs H_2S/hr) x (240 hr/well) x (9 wells/event) x (1 event/yr) / (2,000 lb/ton) = 43.6 tons H_2S/yr

Injection Flowback: During flowback of the injection wells, steam flows to the PTU, where air emissions occur. Emission rates are dependent upon the concentration of the pollutants in the NCG, as well as the flow rate of the NCG (1,177 pounds per hour during flowback). The annual emission estimates are based on an anticipated 24 hours per flowback event each for a total of 12 injection wells[6], once per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (1,177 lbs NCG/hr) = 9.95 lbs H_2S/hr
- Annual: (9.95 lbs H_2S/hr) x (24 hr/well) x (12 wells/event) x (1 event/yr) / (2,000 lb/ton) = 1.43 tons H_2S/yr

Injection Well Testing: During testing of the injection wells, steam flows to the MTU, where air emissions occur. Emission rates are dependent upon the concentration of the pollutants in the NCG, as well as

[6] Although the ENGP will include only eleven (11) injection wells, the hours presented here and utilized in the emission estimates and associated modeling are considered conservative and representative as they are based on twelve (12) injection wells.

the flow rate of the NCG (4,777 pounds per hour during testing). The annual emission estimates are based on an anticipated 240 hours per testing event each for a total of 12 wells[7], once per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (4,777 lbs NCG/hr) = 40.4 lbs H_2S/hr
- Annual: (40.4 lbs H_2S/hr) x (240 hr/well) x (12 wells/event) x (1 event/yr) / (2,000 lb/ton) = 58.2 tons H_2S/yr

Commissioning: Commissioning of the wells is a one-time event that occurs during the first year of operation. During well commissioning, steam flows to the PTU during well warm-up, to the rock muffler during production line and equipment warm-up and steam blow, to the sparger during load testing and performance testing, and to both the rock muffler and sparger during turbine preheat. Note, the example calculation in the first bullet below demonstrates how the maximum hourly emissions were calculated, which occur at the rock muffler when the NCG flow rate is at its highest point during Commissioning (15,854 pounds per hour of NCG). This occurs for an estimated 336 hours per year. For the other steps involved in well commissioning, hourly emission rates are equivalent or lower and the total duration of each step is different. Each of these rates and durations are listed in the second bullet, where annual emissions are calculated.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) = 134 lbs H_2S/hr
- Annual: [(134 lbs H_2S/hr) x (336 hr/yr) + (24.8 lbs H_2S/hr) x (216 hr/yr) + (1.21 lbs H_2S/hr) x (168 hr/yr) + (0.804 lbs H_2S/hr) x (168 hr/yr)] / (2000 lbs/ton) = 25.4 tons H_2S/yr

A summary of estimated emissions from the Well Testing and Commissioning processes are provided in **Table 2**.

Table 2. Maximum Emissions – Well Testing and Commissioning

	Production Flow Back Testing [a]		Production Well Testing [b]		Injection Flow Back Testing [c]		Injection Well Testing [b]		Commissioning [d]	
Pollutant	**(lbs/hr)**	**(tpy)**	**(lbs/hr)**	**(tpy)**	**(lbs/hr)**	**(tpy)**	**(lbs/hr)**	**(tpy)**	**(lbs/hr)**	**(tpy)**
NO_X	--	--	--	--	--	--	--	--	--	--
CO	--	--	--	--	--	--	--	--	--	--
VOC	0.03	<0.01	0.14	0.15	0.03	<0.01	0.14	0.20	0.45	0.12
$PM_{10}/PM_{2.5}$	--	--	--	--	--	--	--	--	--	--
SO_x	--	--	--	--	--	--	--	--	--	--
H_2S	9.95	1.07	40.4	43.6	9.95	1.43	40.4	58.2	134	25.4
HAPs	0.03	<0.01	0.14	0.15	0.03	<0.01	0.14	0.20	0.45	0.12
Ammonia	0.10	0.01	0.41	0.44	0.10	0.01	0.41	0.59	126	11.0
CO_2e [e]	1,187	128	4,818	5,204	1,187	171	4,818	6,938	15,990	4,349

[7] Although the ENGP will include only eleven (11) injection wells, the hours presented here and utilized in the emission estimates and associated modeling are considered conservative and representative as they are based on twelve (12) injection wells.

Notes:

[a] Emissions emitted from the MTU during commissioning and the PTU during non-commissioning operations.

[b] Emissions emitted from the MTU.

[c] Emissions emitted from the PTU.

[d] Emissions emitted at varying rates between the PTU, RM, and cooling towers.

[e] CO_2e emissions in the "tpy" column are reported in short tons and not metric tons.

-- Pollutant not emitted

Maximum Emissions – Startup and Shutdown

Cold Startup: During cold startup, steam flows to the PTU during well warm-up, to the rock muffler during production line and equipment warm-up and functional trip testing, to the sparger during steam delivery to the turbine, and to both the rock muffler and the sparger during turbine preheat and auxiliary equipment startup. Note, the first bullet below demonstrates how the maximum hourly emissions were calculated, which occur when the NCG flow rate is at its highest point during cold startup (15,854 pounds per hour of NCG). This could occur for up to an estimated 74 hours per year. For the other steps involved in cold startup, hourly emission rates are equivalent or lower and the total duration of each step is different. Each of these rates and durations are listed in the second bullet, where annual emissions are calculated.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) = 134 lbs H_2S/hr
- Annual: [(134 lbs H_2S/hr) x (74 hr/yr) + (24.8 lbs H_2S/hr) x (120 hr/yr) + (0.293 lbs H_2S/hr) x (42 hr/yr) + (0.804 lbs H_2S/hr) x (42 hr/yr)] / (2000 lbs/ton) = 6.47 tons H_2S/yr

Warm Startup: During warm startup, steam flows to the rock muffler during Step 1 and to both the rock muffler and the turbine during Step 2. Note, the first bullet below demonstrates how the maximum hourly emissions were calculated, which occur at the rock muffler when the NCG flow rate is at its highest point during warm startup (15,854 pounds per hour of NCG). This would occur for up to an estimated 300 hours per year. For the other steps involved in warm startup, hourly emission rates were estimated to be equivalent or lower and the total duration of each step is different. Each of these rates and durations are listed in the second bullet, where annual emissions are calculated.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) = 134 lbs H_2S/hr
- Annual: [(134 lbs H_2S/hr) x (300 hr/yr) + (0.468 lbs H_2S/hr) x (100 hr/yr) + (0.804 lbs H_2S/hr) x (100 hr/yr)] / (2000 lbs/ton) = 20.2 tons H_2S/yr

Facility Shutdown: During shutdown of the process equipment, steam is vented through the rock muffler, starting at an initial maximum rate of 2,296,528 pounds per hour and slowly decreasing over the course of 36 hours, as each of the 9 production wells goes offline, to a final flow rate of 0 pounds per hour. In the calculations, the steam flow rate decreases in a stepwise function every 4 hours as each production well goes offline. During the initial maximum steam flow, the flow rate is greater than the sum of the high-pressure and standard-pressure steam flows, and thus an NCG correction factor of 59% is applied. This is based on the low-pressure steam flow being comprised of only a fraction of the NCG concentration compared to the high- and standard-pressure steam flows. Once the total steam flow rate drops below the sum of the high-and standard-pressure steam flows, this correction factor is removed. Thus, the highest flow of NCG occurs after 3 of the production wells have gone offline, approximately

12 hours following initiation of shutdown. During this period, the NCG flow rate is estimated at 17,993 pounds per hour, which would correspond to the maximum hourly air emissions. The calculations consider an H_2S concentration of 0.00845 pounds per pound of NCG and a maximum duration of shutdown of 198 hours per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (17,993 lbs NCG/hr) = 152 lbs H_2S/hr
- Annual: (152 lbs/hr) x (198 hours/year) / (2,000 lbs/ton) = 15.1 tpy

Estimated emissions from Startup and Shutdown processes are summarized in **Table 3**.

Table 3. Maximum Emissions – Startup and Shutdown

Pollutant	Cold Startup [a]		Warm Startup [b]		Shutdown [c]	
	(lbs/hr)	(tpy)	(lbs/hr)	(tpy)	(lbs/hr)	(tpy)
NO_X	--	--	--	--	--	--
CO	--	--	--	--	--	--
VOC	0.45	0.02	0.45	0.08	0.51	0.05
$PM_{10}/PM_{2.5}$	--	--	--	--	--	--
SO_x	--	--	--	--	--	--
H_2S	134	6.47	134	20.2	152	15.1
HAPs	0.45	0.02	0.45	0.08	0.52	0.05
Ammonia	126	2.72	126	6.54	1.54	0.15
CO_2e [d]	15,990	851	15,990	2,709	18,148	1,797

Notes:

[a] Emissions emitted at varying rates between the PTU, RM, and cooling towers.

[b] Emissions emitted at varying rates between the RM and cooling towers.

[c] Emissions emitted from the RM.

[d] CO_2e emissions in the "tpy" column are reported in short tons and not metric tons.

-- Pollutant not emitted.

Maximum Emissions – Normal Continuous Generation

Routine Operation (H_2S): During routine operation, steam (including the NCG portion) flows simultaneously to the sparger and cooling tower, where air emissions occur. The emission rates are dependent upon the concentration of the pollutant (for the pollutant in this example, 0.00845 pounds H_2S per pound of NCG), the flow rate of NCG (15,854 pounds per hour during normal operation to both the sparger and the cooling tower), and the applicable control efficiency (a combined 98.5% H_2S control by the sparger and Ox-Box). Additionally, the Applicant assumed a ratio of 60% for the portion of H_2S partitioned into the NCG (and thus, controlled at the sparger), with the remaining 40% staying in the liquid phase to be controlled at the cooling tower. Annual emissions estimates assume up to 8,760 hours of routine operation per year.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (60%) x (1-98.5%) + (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (1-60%) x (1-98.5%) = 2.01 lbs H_2S/hr
- Annual: (2.01 lbs H_2S/hr) x (8,760 hr/yr) / (2000 lbs/ton) = 8.81 tons H_2S/yr

Sparger Bypass/Breakdown: Up to 200 hours per year of bypass/breakdown of the sparger control are anticipated. Emissions under this scenario are calculated similarly to routine operation, but no control efficiency for the sparger is applied.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (60%) + (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (1-60%) x (1-98.5%) = 81.2 lbs H_2S/hr
- Annual: (81.2 lbs H_2S/hr) x (200 hr/yr) / (2000 lbs/ton) = 8.12 tons H_2S/yr

Ox-Box Bypass/Breakdown: Up to 200 hours per year of bypass/breakdown of the Ox-Box are anticipated. Emissions under this scenario are calculated similarly to routine operation, but no control efficiency at the cooling tower is applied.

- Max. Hourly: (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (60%) x (1-98.5%) + (0.00845 lbs H_2S/lb NCG) x (15,854 lbs NCG/hr) x (1-60%) = 54.8 lbs H_2S/hr
- Annual: (54.8 lbs H_2S/hr) x (200 hr/yr) / (2000 lbs/ton) = 5.48 tons H_2S/yr

Routine Operation (PM_{10}): An example calculation for PM_{10} is provided here, as it is calculated differently in this process compared to the volatile components like H_2S. During routine operation, water is circulated in the cooling tower at a rate of 213,500 gallons per minute. Per the Applicant, a maximum concentration of TDS in the circulated water of 9,000 ppm was assumed based on measurements from other Applicant-owned facilities. In addition, the cooling tower was assumed to have a drift loss of 0.0005% due to the use of high-efficiency drift eliminators. Lastly, a PM_{10} fraction of the total suspended particulate (TSP) of 70% was assumed, based on South Coast Air Quality Management District guidance.[8] Annual emissions estimates assume up to 8,760 hours of routine operation per year.

- Max. Hourly: (213,500 gpm) x (60 mins/hr) x (0.0005%) x (8.3453 lbs/gallon) x (9,000 ppmw/1,000,000) x (70%) = 3.37 lbs PM_{10}/hr
- Annual: (3.37 lbs PM_{10}/hr) x (8,760 hr/yr) / (2000 lbs/ton) = 14.7 tons PM_{10}/yr

Estimated emissions from normal operation of the ENGP facility are summarized in **Table 4**.

[8] South Coast Air Quality Management District. 2006. Final – Methodology to Calculate Particulate Matter (PM) 2.5 and PM 2.5 Significance Thresholds. Appendix A. October.

Table 4. Maximum Emissions – Power Generation Operation						
	Routine Operations [a]		Sparger Bypass/ Breakdown [b]		Biological Oxidization Box Bypass/Breakdown [b]	
Pollutant	(lbs/hr)	(tpy)	(lbs/hr)	(tpy)	(lbs/hr)	(tpy)
NO_X	--	--	--	--	--	--
CO	--	--	--	--	--	--
VOC	0.46	2.00	0.46	0.05	0.46	0.05
PM_{10}	3.37	14.7	3.37	0.34	3.37	0.34
$PM_{2.5}$	2.02	8.85	2.02	0.20	2.02	0.20
SO_x	--	--	--	--	--	--
H_2S	2.01	8.81	81.2	8.12	54.8	5.48
HAPs	0.46	2.00	0.46	0.05	0.46	0.05
Ammonia	128	559	564	56.4	128	12.8
CO_2e [c]	15,990	70,035	15,990	1,599	15,990	1,599

Notes:

[a] Annual emissions for routine power generation operations conservatively assume an estimated 8,760 hours of operation without any startups, shutdowns, or emission control downtime. These emissions are emitted from the cooling towers.

[b] Emissions emitted from the cooling towers. Sparger bypass/breakdown emissions include emissions from normal cooling tower operation and biological oxidization box bypass/breakdown emissions include emissions from the normal sparger operation, as both the sparger and biological oxidation box systems operate independently and emit through the cooling towers. These emissions represent unforeseeable and non-preventable operations, which would be subject to ICAPCD breakdown requirements.

[c] CO_2e emissions in the "tpy" column are reported in short tons and not metric tons.

-- Pollutant not emitted.

Maximum Emissions – Other Sources

Fire pump: Emission rates from the fire pump are calculated based on the engine rating (236 kW) and the manufacturer's emission factors (for this example, a PM_{10} emission factor of 0.11 g PM_{10}/kW-hr). The annual emission estimate is derived from the anticipated operating hours for maintenance and readiness testing, which is 50 hours per year.

- Max. Hourly: (236 kW) x (0.11 g PM_{10}/kW-hr) / (453.6 g/lb) = 0.057 lbs PM_{10}/hr
- Annual: (0.057 lbs/hr) x (50 hr/yr) / (2000 lbs/ton) = 0.0014 tons PM_{10}/yr

Emergency Generators: Emission rates from the emergency generators are calculated using their rating (3,250 kW), the manufacturer's emission factors (for this example, 0.03 g PM_{10}/kW-hr), and the number of generators (three). The annual emission estimates are derived from the projected operating hours for maintenance and readiness testing, which is 50 hours per generator per year.

- Max. Hourly:(3,250 kW) x (0.03 g/kW-hr) x (3 generators) / (453.6 g/lb) = 0.64 lbs PM_{10}/hr
- Annual: (0.64 lbs PM_{10}/hr) x (50 hr/yr) / (2000 lbs/ton) = 0.02 tons PM_{10}/yr

Operation and Maintenance (O&M) Equipment: O&M equipment to be used during the operational phase of the project include water trucks, dump trucks, on-site pickup trucks, forklifts, boom trucks, cranes, excavators, backhoes, yard dogs, pressure washers, welders, manlifts, air compressors, and carry decks. Emissions from equipment were calculated using emission factors (in grams per horsepower-hour) obtained from the CalEEMod® model and emissions from on-road vehicles were calculated using emission factors (in pounds per hour or pounds per mile) obtained from the EMFAC2021 model for Imperial County (for idling and exhaust emissions) and from the CalEEMod® model for particulate matter from paved road travel.

Estimated emissions from the fire pump, emergency generators, and O&M equipment are provided in **Table 5**.

Table 5. Worst-Case Hourly Emissions by Source or Point of Release

	Maximum Hourly Emissions (lb/hr)						
Pollutant	**PTU**	**MTU**	**RM**	**Cooling Tower & Sparger**	**Fire Pump**	**Emergency Generators [a]**	**O&M [b]**
NO_X	--	--	--	--	1.78	14.4	8.26
CO	--	--	--	--	0.42	75.2	23.3
VOC	0.08	0.14	0.51	0.46	0.05	4.08	0.79
SO_x	--	--	--	--	<0.01	<0.01	0.07
PM_{10}	--	--	--	3.37	0.06	0.64	0.52
$PM_{2.5}$	--	--	--	2.02	0.06	0.64	0.28
H_2S	24.8	40.4	152	134	--	--	--
HAPs	0.08	0.14	0.52	0.46	0.06	0.67	0.51c
Ammonia	0.25	0.41	1.54	128	--	1.01	--
CO_2e	2,963	4,818	18,148	15,990	131	14,848	7,305

Notes:

[a] Emissions include those from three 3.25 MW generators.

[b] Emissions include those associated with gas-insulated equipment, the HCl scrubber, and O&M equipment and vehicles.

[c] Combustion-related HAPs conservatively assumed to be equal to PM_{10} with DPM considered a surrogate for HAPs.

-- Pollutant not emitted

Table 6. Summary – Project Operation Annual Emissions

Pollutant	First Year Annual Emissions (tpy) [c]				Subsequent Year Annual Emissions with Startups, Shutdowns, & Emission Control Downtime (tpy)				Subsequent Year Annual Emissions without Startups, Shutdowns, & Emission Control Downtime (tpy)			
	Steam System [a]	Fire Pump	Emergency Generators [b]	O&M [d]	Steam System [a]	Fire Pump	Emergency Generators [b]	O&M [d]	Steam System [a]	Fire Pump	Emergency Generators [b]	O&M [d]
NO_x	--	0.04	0.36	1.52	--	0.04	0.36	1.52	--	0.04	0.36	1.52
CO	--	0.01	1.88	5.25	--	0.01	1.88	5.25	--	0.01	1.88	5.25
VOC	1.03	<0.01	0.10	0.16	1.86	<0.01	0.10	0.16	2.00	<0.01	0.10	0.16
PM_{10}	2.94	<0.01	0.02	0.10	12.6	<0.01	0.02	0.10	14.8	<0.01	0.02	0.10
$PM_{2.5}$	1.76	<0.01	0.02	0.05	7.53	<0.01	0.02	0.05	8.85	<0.01	0.02	0.05
SO_x	--	<0.01	<0.01	0.01	--	<0.01	<0.01	0.01	--	<0.01	<0.01	0.01
H_2S	186	--	--	--	64.9	--	--	--	8.81	--	--	--
HAPs	1.03	<0.01	0.02	0.57[e]	1.87	<0.01	0.02	0.57[e]	2.00	<0.01	0.02	0.57[e]
Ammonia	176	--	0.03	--	529	--	0.03	--	559	--	0.03	--
CO_2e [f]	36,106	3.27	371	1,484	65,281	3.27	371	1,484	70,035	3.27	371	1.484

Notes:

a Steam system emissions are emitted from the PTU, RM, or cooling towers.

b Emissions include those from three 3.25 MW generators.

c First year annual emissions include commissioning activities with the remaining year routine operations.

d Emissions include those associated with gas-insulated equipment, the HCl scrubber, and O&M equipment and vehicles.

e Combustion-related HAPs conservatively assumed to be equal to PM_{10} with DPM considered a surrogate for HAPs.

f CO_2e emissions in the "tpy" column are reported in short tons and not metric tons.

-- Pollutant not emitted.

Applicable Rules and Regulations

The following section summarizes the Air District Rules and Regulations which are applicable to the new emissions units and processes proposed to be operated by the Applicant at the ENGP.

Rule 109 – Source Sampling

Air District Rule 109 outlines facility design requirements for source sampling for any facility emitting pollutants which have emission limits. The Applicant is expected to comply with this rule by providing sampling ports and platforms, along with proper access and sampling utilities, so that source samples can be taken to determine the compliance status of the facility's emissions units.

Rule 111 – Equipment Breakdown

Air District Rule 111 details the notification and corrective action requirements in an equipment breakdown situation. As the operator and permittee of the ENGP, the Applicant is expected to comply with this rule by completing the required procedures if a breakdown condition should occur. The Air Pollution Control Officer (APCO) shall be notified of a breakdown condition as soon as reasonably possible, but no later than two (2) hours after its detection. The reporting requirements under this rule must be completed within ten days after a breakdown occurrence has been corrected.

Rule 201 – Permits Required

Except as exempted within the Air District Rules and Regulations, new or modified sources which may emit or control air contaminants must obtain written authorization from the ICAPCD prior to construction, and any person who operates a piece of equipment that emits or control air contaminants is required to obtain a PTO. The ENGP will include emissions sources and abatement equipment that require both an ATC and a PTO from the Air District. However, because the proposed project is a power plant seeking certification by the CEC, the application will be processed according to the procedures outlined in Rule 207 Section D.4 (see the discussion under Rule 207 for additional information).

Rule 202 – Exemptions

Air District Rule 202 includes a list of equipment that are exempt from obtaining an ATC or PTO. Section E.8 exempts storage tanks from permitting requirements if they contain unheated organic materials with boiling points over 302 degrees Fahrenheit or vapor pressures less than 0.1 pounds per square inch absolute (psia). The Applicant provided information regarding the contents of storage tanks in supplemental materials dated June 12, 2023 and October 4, 2023. This information included the identities of the materials to be stored in the tanks at the ENGP, which include diesel, used oil, lube oil, and a naturally occurring radioactive materials (NORMs) inhibitor containing a mixture of amine triphosphate, trisodium phosphate, and ethylene glycol. Based on the identities of the materials to be contained in the storage tanks, all tanks would meet exemptions from Rule 202 and thus exempt from permitting.

Rule 204 – Applications

The Applicant has satisfied Air District Rule 204 with the submittal of a complete permit application to the Air District for the proposed construction of the ENGP. The application was deemed complete by the Air District on June 22, 2023. Additionally, as the Air District conducted its full review of the proposed project, the Applicant provided further details regarding project equipment and emission sources.

Rule 206 – Processing of Applications

Air District Rule 206 references guidelines established by the APCO for the processing of applications and issuance of permits. The proposed project does not qualify for a ministerial permit and thus will be processed as a discretionary permit project. Section C of the rule specifies the public review and noticing requirements associated with discretionary permits. Specifically, Section C.3 lists emissions thresholds above which public notice is required. Based on the permit application, the ENGP will exceed the emissions threshold in Section C.3 of 100 pounds per day for H_2S and thus will trigger public notice requirements of this rule.

Rule 207 – New and Modified Stationary Source Review

Air District Rule 207 establishes preconstruction review requirements for new and modified stationary sources to ensure that the operation of such sources does not interfere with the attainment or maintenance of ambient air quality standards (AAQS). The rule includes standards for the implementation of best available control technology (BACT) and emission offsets, as well as provisions for an air quality impact assessment, if requested by the APCO. Section D.4 specifies the administrative requirements associated with projects involving power plants 50 MW and greater. Because the ENGP involves the development of a power plant with a net generation capacity of 140 MW, it is subject to these provisions. Additional information regarding BACT, offset applicability, an evaluation of AAQS, and the administrative requirements under this rule is included in the following sections.

Best Available Control Technology (BACT)

Rule 207.C.1.a requires BACT for equipment with a PTE of 25 pounds per day (lbs/day) or more of any nonattainment pollutant, including PM_{10}, or their precursors. Rule 207.C.1.c requires BACT for equipment with a PTE equal to or greater than 55 lbs/day of H_2S. Due to the ENGP facility's potential emissions, BACT will be triggered for PM_{10} and H_2S emissions.

The ENGP facility's PTE for PM_{10} is 81.7 lbs/day, which originates primarily from the facility's cooling tower. The ENGP facility's PTE for H_2S originates from two primary sources: the steam condensate into which the H_2S dissolves and the NCG that remains after the steam is condensed. This BACT analysis examines these two sources separately, while acknowledging that the ENGP facility's H_2S emissions limits are based on the combined potential emissions from both sources.

BACT for Cooling Tower – PM_{10}

In the Applicant's application, BACT for the ENGP's cooling tower PM_{10} emissions was proposed as high efficiency cellular type drift eliminators with a 0.0005% drift rate. This proposed BACT was based on a San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT Guideline and information derived from USEPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse.

At the Air District's request, the Applicant evaluated, in a subsequent submission, air-cooled condensers (ACCs) with evaporative cooling as a potential control alternative. In ACCs, the condensing vapor flows inside a bank of tubes and ambient air blown across the tubes by fans serves as the coolant. Evaporative pre-cooling (e.g., adiabatic cooling) improves cooling capacity by misting the incoming ambient air, causing evaporation of the mist and thus reducing the temperature of the cooling air. ACC technology was determined by the Applicant to be technically infeasible for this application due to its incompatibility with flash system geothermal plants, such as the ENGP design, since ACCs can be susceptible to corrosion and sulfur precipitation impacts. In addition, the Applicant provided heat balance case studies run for the ENGP indicating that the expected power output during the summer months with an ACC system would be on the order of 15 percent lower than with the proposed wet cooling system, and up to 35 percent less under extreme temperatures. With this additional information, the Air District has concluded that high efficiency drift eliminators with a maximum drift loss of 0.0005% meet the BACT requirement for this project.

BACT for Condensate – H_2S

In the Applicant's initial application, BACT for the ENGP's condensate H_2S emissions was proposed as an Ox-Box system based on a March 2017 BACT analysis conducted by CalEnergy for the J.J. Elmore Geothermal Power Plant ("2017 BACT Analysis"). The evaluated Ox-Box system would be located adjacent to the cooling tower and operate as a bio-trickling filter involving several species of sulfur bacteria and denitrifying bacteria to oxidize the H_2S into elemental sulfur, and subsequently into sulfates.

In addition to the Ox-Box system, the 2017 BACT Analysis evaluated a BIOX (liquid) system, as well as chemical oxidation and iron chelate technologies as alternative control solutions for H_2S emissions from the steam condensate. The BIOX (liquid) system consists of adding an oxidizing biocide into the condensate to convert dissolved H_2S to water-soluble sulfates. Though technically feasible, the BIOX (liquid) system was found to be less cost-effective compared to the Ox-Box system. The chemical oxidation and iron chelate technology was also identified to be technically feasible, but less cost-effective than the Ox-Box system.

At the Air District's request, the Applicant evaluated, in a subsequent submission, direct injection of condensate as a potential control alternative. In this alternative, the steam condensate produced at the condenser would be mixed with the brine effluent from flash separators and reinjected into the geothermal reservoir. This process would eliminate H_2S emissions from the condensate stream but that would make the condensate unavailable as a cooling water makeup resource and results in 100 percent of the cooling water needing to be obtained from freshwater resources. Given this issue, the Applicant argued this alternative is technically infeasible due to the limited availability of freshwater for industrial use in the Imperial Valley. With this additional information, the Air District concludes that the Ox-Box system meets the BACT requirement for this project.

BACT for NCG stream – H_2S

In the Applicant's initial application, BACT for the ENGP's NCG H_2S emissions was proposed as a sparger system with BIOX based on the analysis conducted in the 2017 BACT Analysis. In a sparger system, NCG is dissolved in the cooling tower water and the BIOX oxidizes H_2S into sulfate.

In addition to the sparger system, the 2017 BACT Analysis evaluated regenerative thermal oxidizers (RTOs) and bioreactors as alternative control solutions for NCG H_2S emissions. Both the RTO and bioreactor control options, though identified as technically feasible, were found to be less cost-effective than the sparger alternative in the 2017 BACT analysis.

At the Air District's request, the Applicant evaluated, in a subsequent submission, various liquid redox methods, including the Stretford Process, SulFerox, and LO-CAT, as control alternatives. Per the

Applicant, these technologies are more suited to gas streams with low concentrations of ammonia, as high ammonia concentrations promote partitioning of H_2S into the condensate, leading to H_2S emissions from the cooling tower or the need for additional treatment of the condensate. The Stretford Process, which uses a vanadium solution, was identified by the Applicant as technically infeasible because the manufacture of Stretford units has been discontinued (i.e., no longer commercially available). SulFerox, which uses chelated iron (III), was also deemed technically infeasible by the Applicant due to the uncertainty of commercial availability of vendors and engineering to support the installation, operation, and maintenance of SulFerox systems. LO-CAT, which also uses chelated iron, was identified as technically feasible but was found to be less cost-effective as the sparger system. With this additional information, the Air District agrees with the Applicant's original conclusion that the sparger with oxidizing biocide abatement meets BACT requirements for this project.

Offsets

Section C.2 of Rule 207 requires emission offsets for any new or modified stationary emission source with a PTE greater than 137 pounds per day for VOCs, PM_{10}, NO_x, CO, or SO_x. Per the emissions calculations provided by the Applicant and confirmed by the Air District, the proposed ENGP will not have emissions that exceed these thresholds. Therefore, the Applicant will not be required to offset emissions under Air District Rule 207.

Air Quality Impact Analysis

Section C.5.b.1 of Rule 207 states that emissions from a new or modified emissions unit shall not cause or make worse a violation of an AAQS. For the purposes of the rule, AAQS shall be interpreted to include both state and federal AAQS. To address these requirements under Rule 207, the applicant provided an air quality impact analysis for the criteria air pollutants from operation of the ENGP. Specifically, the Applicant's analysis evaluated the impacts associated with the emissions associated with diesel combustion from routine maintenance and testing of three emergency generators and one fire pump, the 13 MTU well pad locations, the two PTUs, the RM, HCl scrubber, and the 14 cooling tower cells.

The Applicant conducted the dispersion modeling using the AMS/EPA Regulatory Model Improvement Committee (AERMIC) Model (AERMOD) Version 22112. AERMOD has been approved for use in various regulatory applications by USEPA and California Air Resources Board (CARB). AERMOD uses mathematical equations to simulate the dispersion of air pollutants in the atmosphere for a grid of receptors. For each receptor location, the model generates air concentrations that result from emissions from multiple sources.

The dispersion modeling utilized 5 years of hourly meteorological data collected at the Imperial County Airport.[9] A cartesian receptor grid was used to model receptors out to 10 kilometers from the ambient air boundary in compliance with South Coast Air Quality Management District (SCAQMD) guidelines[10] as a reference. Additional receptors spaced 25 meters apart were placed along the facility's ambient air boundary and along the perimeter of each off-site well pad. AERMOD calculated air pollutant

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[9] The 5 years used in this analysis include 2015 through 2018 and 2021. The years 2019 and 2020 were not included because they were likely determined to be incomplete by CARB.
[10] Available at: https://www.aqmd.gov/home/air-quality/meteorological-data/modeling-guidance#Receptor.

concentrations at each receptor for the averaging periods necessary to demonstrate compliance with state and federal AAQS.

The maximum concentrations for each pollutant and averaging period were compared to the USEPA significant impact levels (SILs). The modeled concentrations were found to be less than the SIL for all pollutants and averaging periods with the exception of 24-hour PM_{10}, as well as 24-hour and annual $PM_{2.5}$. In addition to the SILs, the modeled concentrations of each pollutant were compared to the CAAQS and NAAQS. This additional analysis is required for 24-hour PM_{10} and $PM_{2.5}$ but conservatively demonstrates the impacts from other pollutants since those SILs were not exceeded. A comparison to the NAAQS and CAAQS requires the background pollutant concentration to be included. The background data were collected for years 2019-2021 based on the most representative monitoring stations in Imperial County.

Table 7. Operational Air Quality Impact Results – Ambient Air Quality Standards							
Pollutant	**Averaging Period**	**Maximum Conc. (μg/m^3)**	**Background Conc. (μg/m^3)**	**Total Conc. (μg/m^3)**	**CAAQS (μg/m^3)**	**NAAQS (μg/m^3)**	**Exceeds Standard?**
NO_2	1-hour max. (CAAQS)	142	105	247	339	--	No
	5-year avg. of 1-hour yearly 98th percentiles (NAAQS)	1.23	65.2	66.4	--	188	No
	Annual max.	0.06	17.4	17.5	57	100	No
H_2S	1-hour max. (CAAQS)	36.7	--	36.7	42	--	No
CO	1-hour max. (CAAQS and NAAQS)	1,421	5,266	6,687	23,000	40,000	No
	8-hour max. (CAAQS and NAAQS)	114	3,549	3,663	10,000	10,000	No
SO_2	1-hour max. (CAAQS and NAAQS)	<0.01	22.5	22.5	655	196	No
	3-hour max. (NAAQS)	<0.01	22.5	22.5	--	1,300	No
	24-hour max. (CAAQS and NAAQS)	<0.01	7.10	7.10	105	365	No
	Annual max. (NAAQS)	<0.01	1.10	1.10	--	80	No
PM_{10}	24-hour max. (CAAQS)	7.11	241.3	248	50	--	Yes
	24-hour avg. high-sixth-high (NAAQS)	4.34	142	146	--	150	No
	Annual max. (CAAQS)	0.64	39.8	40.4	20	--	Yes
$PM_{2.5}$	5-year avg. of 24-hour yearly 98th percentiles (NAAQS)	1.96	21.0	23.0	--	35	No
	Annual max. (CAAQS)	0.38	9.40	9.78	12	--	No
	5-year avg. of annual concentrations (NAAQS)	0.36	8.67	9.03	--	12.0	No

The impact analysis calculated a maximum incremental increase for each pollutant for each applicable averaging period, as shown in the table above. This table conservatively presents maximum modeled concentrations as project impact. When added to the background concentration, the resulting concentration represents the maximum total predicted concentration. The resulting total pollutant concentration were then compared to the NAAQS and CAAQS. The modeling results for the operation of the ENGP show that the maximum 24-hour and annual PM_{10} concentrations exceed the CAAQS. However, the 24-hour and annual background PM_{10} concentrations already exceed the CAAQS at 241.3 $\mu g/m^3$ and 39.8 $\mu g/m^3$, respectively, using data from 2019-2021 from the Niland monitoring site (AQS Site ID 06-025-4004). Although the ENGP exceeds the 24-hour PM_{10} SIL, emissions are expected to be less than the ICAPCD Rule 207 offset thresholds. Furthermore, the ENGP will implement BACT to reduce particulate matter emissions from the cooling tower and to minimize emissions from diesel combustion by using a Tier 3-certified fire pump and Tier 4-certified emergency generators.

The secondary formation of pollutants – O_3 and secondary $PM_{2.5}$ – was accounted by the Applicant when analyzing the impacts from the ENGP. The project does not result in the direct emissions of these pollutants, but direct emissions of primary pollutants such as NO_x, SO_2, and VOCs will contribute to the formation of secondary pollutants that must be compared to the CAAQS and NAAQS. Secondary pollutant impacts were estimated using USEPA Maximum Emission Rate of Precursors (MERPS) View Qlik.[11] Secondary impacts are estimated by MERPS using empirical relationships between precursor emission rates and resultant secondary pollutant concentrations for numerous scenarios that vary by emissions source parameters and geographical location. For the ENGP, the modeled secondary pollutant impacts for a 10-meter stack in Los Angeles County were used to represent the project, then scaled based on the estimated precursor emission rates from operation of the project. The following table provides the estimated secondary impacts from the project and demonstrates that the $PM_{2.5}$ concentration would not result in an exceedance of the NAAQS and CAAQS when added to the estimated primary $PM_{2.5}$ concentration. Furthermore, the estimated secondary O_3 concentration was below the 8-hour maximum SIL of 1.96 $\mu g/m^3$. Therefore, secondary pollutant impacts would not cause the project to exceed any SIL or AAQS.

[11] USEPA. MERPS View Qlik. Available at: https://www.epa.gov/scram/merps-view-qlik. Accessed: October 2023.

Table 8. Operational Air Quality Impact Results – Secondary Emissions from Precursors					
Pollutant	**Precursor**	**Modeled Precursor Emission Rate (tpy)**	**Modeled Secondary Impact Concentration (µg/m³)**	**Project Emissions (tpy)**	**Project Secondary Impact Concentration (µg/m³)**
24-Hour $PM_{2.5}$	NO_X	500	0.025	1.92	<0.01
	SO_2	500	0.077	0.01	<0.01
Annual $PM_{2.5}$	NO_X	500	0.001	1.92	<0.01
	SO_2	500	0.002	0.01	<0.01
8-Hour O_3	NO_X	500	0.84	1.92	<0.01
	VOC	500	0.06	2.26	<0.01

Administrative Requirements

Section D.4.e of Rule 207 states that within 180 days of accepting an application for certification as complete, the APCO shall make a preliminary decision on whether the proposed power plant meets the requirements of Rule 207 and all other applicable District regulations. This preliminary decision shall be finalized by the APCO only after being subject to the public notice and comment requirements of Air District Rule 206. Section D.4.f of Rule 207 states that within 240 days of accepting an application for certification as complete, the APCO shall issue and submit to the California Energy Commission a preliminary determination of compliance. A preliminary determination of compliance shall confer the same rights and privileges as an ATC only when and if the California Energy Commission approves the application for certification and the California Energy Commission certificate includes all conditions of the final determination of compliance. Any applicant receiving a certificate from the California Energy Commission pursuant to Section D.4 of Rule 207 and demonstrates compliance with all conditions related to air pollution of the certificate shall be issued a PTO by the APCO.

Rule 208 – Permit to Operate

The Air District may inspect and evaluate the ENGP facility, including its emissions units and abatement systems, prior to allowing the stationary source to operate under a PTO. The applicant is expected to fully comply with all provisions and conditions of the CEC's certificate, including all conditions related to air pollution, as well as comply with all applicable laws, rules, standards, and guidelines. The APCO will issue a PTO upon a finding that the facility is in compliance with all required provisions.

Rule 400 – Fuel Burning Equipment Oxides of Nitrogen

Air District Rule 400 applies to emissions of nitrous oxides from new and existing stationary fuel burning equipment, including internal combustion engines. However, per the applicability criteria in Section A of Rule 400.3, internal combustion engines with a rating greater than 50 brake horsepower (bhp) are subject to the provisions of Rule 400.3 and not Rule 400. All internal combustion engines proposed by the Applicant are rated greater than 50 bhp; therefore, the ENGP will not be subject to this rule.

Rule 400.3 – Internal Combustion Engines

Air District Rule 400.3 establishes NO_X and CO emission limits for any internal combustion engine with a bhp rating greater than 50 that requires a PTO. Owners or operators of any internal combustion engine subject to Rule 400.3 shall maintain a monthly engine operating log on-site that includes the engine manufacturer, model, brake horsepower output rating, and combustion method. The log must also include a manual of recommended maintenance from the manufacturer or other maintenance procedure approved by the APCO, a record of routine engine maintenance, a specific emission inspection procedure including an inspection schedule, total hours of operation, and the type of fuel combusted. The owner or operator will also be required to install a non-resettable fuel consumption or time elapsed meter.

Per Rule Section D.4, new or existing emergency standby engines which operate 100 hours or less per calendar year for the purpose of testing and maintenance shall be exempt from the emission limits of the rule. The internal combustion engines proposed by the Applicant are emergency standby engines that will be limited to 50 hours per year for maintenance and testing; therefore, the engines are exempt from the emission limits in the rule. However, the Applicant will still be required to comply with the rule's recordkeeping and records retention requirements.

Rule 401 – Opacity of Emissions

Air District Rule 401 applies to the discharge of pollutants into the atmosphere. The opacity of the emissions from each of the emission units at ENGP, other than water vapor discharge, may not be as dark or darker as designated as No. 1 on the Ringelmann Chart (20% opacity) for a period or periods aggregating more than three minutes in any one hour. The Applicant is expected to comply with this rule by operating all sources according to manufacturer specifications, applying good combustion practices, and maintaining control equipment in good operating order.

Rule 403 – General Limitations on the Discharge of Air – Contaminants

Air District Rule 403 applies to the discharge of air contaminants, combustion contaminants, and particulate matter into the atmosphere. The requirements establish maximum emission rates for particulate matter that vary according to the weight of the materials processed by an emissions unit and/or the volume discharge rate of an emissions unit. The diesel-fired emergency generators proposed by the Applicant are exempt from the requirements of Rule 403(B.4) because they qualify as emergency standby generators. The emergency fire pump will comply with the requirements of Rule 403 Section B.4 by discharging less than 0.01 gr/dscf of gas exhaust. All combustion units proposed by the Applicant are expected to demonstrate compliance with Rule 403 Section B.5 by discharging less than 10 lbs/hr of combustion contaminants based on the emissions calculations provided by the Applicant.

The combustion and non-combustion units that discharge air contaminants and particulate matter into the atmosphere are required to meet the standards outlined within Rule 403 (B.1-B.3). These emission limit rates are listed in Tables 403-1 and 403-2. Based on the emissions calculations provided by the Applicant, compliance with this rule is expected.

Rule 405 – Sulfur Compounds Emissions Standards, Limitations, and Prohibitions

Air District Rule 405 applies to discharges of sulfur compounds into the atmosphere and limits sulfur compound emissions to no more than 0.2 percent by volume from any single source, with certain exceptions. Under this rule, a person shall not burn any liquid or solid fuel having a sulfur content in excess of 0.5 percent by weight.

The Applicant is expected to demonstrate compliance with this rule through regular source testing. Additionally, all diesel fuel combusted at the ENGP facility will be ultra-low sulfur diesel with a sulfur content not to exceed 15 ppm by weight.

Rule 407 – Nuisances

Air District Rule 407 states that no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property. The pollutant emitted by the ENGP that is most likely to lead to a nuisance concern is H_2S. The closest sensitive receptors to the project site are located over a mile away. In addition, the Applicant intends to control its emissions of H_2S with air pollution control equipment meeting BACT. Ultimately, the Applicant is expected to comply with this Rule by operating all sources according to manufacturer specifications, applying good combustion practices, and maintaining control equipment in good operating order.

Regulation VIII – Fugitive Dust (PM10) Rules

The Air District rules under Regulation VIII include requirements and Best Available Control Measures (BACM) which operators must implement in order to reduce fugitive dust emissions from construction and earthmoving activities, open areas, movement of bulk materials, carry out and track out activities, and paved and unpaved roads. The Applicant must meet all the applicable requirements of Air District Rules 800 through 805 while the ENGP facility is constructed and during operation. Per Rule 801, a Dust Control Plan must be prepared by the Applicant and a copy must be available to the Air District upon request, and written notification must be provided to the Air District within 10 days prior to the commencement of any construction activities.

Rule 900 – Procedures for Issuing Permit to Operate for Sources Subject to Title V of the Federal Clean Air Act Amendments of 1990

Air District Rule 900 outlines the applicability and application requirements for a Title V permit. The ENGP does not meet the criteria to be defined as a Major Source under Rule 900 Section B.23 based on the annual potential to emit for the entire facility. Therefore, the Applicant will not be required to apply for a Title V permit in accordance with Rule 900 Section C.1.a.

Rule 1001 – National Emission Standards for Hazardous Air Pollutants

Air District Rule 1001 identifies the provision from Part 61, Chapter I, Title 40 of the Code of Federal Regulations (40 CFR Part 61) that are incorporated as part of the Air District Rules and Regulations. The ENGP is not subject to any of the provisions listed in Rule 1001 Section D; therefore, the Applicant will not be subject to this rule.

Rule 1002 – California Airborne Toxic Control Measures (ATCMs)

Air District Rule 1002 outlines the provisions of the Final Regulation Orders contained in Title 17 of the California Code of Regulations that have been incorporated into the Air District Rules and Regulations. Of the incorporated provisions, the ENGP will be subject to Section 93115 Airborne Toxic Control

Measure for Stationary CI Engines (Diesel ATCM). Each diesel engine driving a proposed emergency combustion unit (e.g., emergency generators, fire pump) will be subject to the requirements of the Diesel ATCM. The permittee will comply with the Diesel ATCM by limiting the hours of maintenance and testing to a maximum of 50 hours per year for each diesel emergency engine at the ENGP facility, as well as ensuring that the facility's workers only use CARB approved fuel for each unit. The proposed emergency standby diesel-fuel engines have emission factors in compliance with the standards in Air District Rule 1002 Section D.

Rule 1003 – Hexavalent Chromium Emissions from Cooling Tower

Air District Rule 1003 establishes provisions to limit potential hexavalent chromium emissions from cooling tower. The Applicant is expected to comply with this rule by not dosing the cooling tower circulating water with chromium containing compounds. To demonstrate compliance with this rule, the Applicant will have to test the cooling tower circulation water every six months to demonstrate that the concentrations of hexavalent chromium do not exceed 0.15 milligrams per liter. In addition, the Applicant will be required to submit a cooling tower compliance plan to the Air District before the ATC and PTO is issued. This plan must be maintained onsite for at least two years and available to the Air District upon request.

Rule 1101 – New Source Performance Standards (NSPS)

Air District Rule 1101 identifies the provisions from 40 CFR Part 60 that are incorporated as part of the Air District Rules and Regulations. The ENGP is not subject to any of the provisions listed in Rule 1101 Section D; therefore, the Applicant will not be subject to this rule.

CA Health & Safety Code 42301.6

California Health & Safety Code, Sec. 42301.6 requires that the Air District prepare a public notice for any new or modified source which emits hazardous air emissions that is located within 1,000 feet from the outer boundary of a school site, prior to approving an ATC or permit modification. The ENGP facility will be located approximately 6.0 miles away from the nearest school sites, which are the high school, middle school, and elementary school of the Calipatria Unified School District (CUSD). These CUSD schools are all located side by side at 601 West Main Street in Calipatria, California. Therefore, based on this analysis, the Applicant will not be required to notice its project to the public under this regulation, since the source is located more than 1,000 feet from the nearest school site. However, the Applicant will still be required to notice its project in accordance with the provisions in Air District Rule 206.

Assembly Bill 2588

The Air Toxics 'Hot Spots" Information and Assessment Act of 1987 (commonly known as Assembly Bill [AB] 2588) established a statewide program for the reporting of air toxics emissions from stationary sources and included requirements for facility risk assessments and public notification of potential health risks. The elements of AB 2588 are codified in California Health & Safety Code, Sec. 44300, et al. California Health & Safety Code, Sec. 44360(a) requires that the Air District prioritize facilities based on submitted emission inventories and place them into one of three categories: high, intermediate, and low priority. Facilities ranked as high priority are required to submit health risk assessments (HRA). Facilities ranked as intermediate priority are considered to be "district tracking" facilities and required to submit a complete toxics inventory once every four years. Facilities ranked as low priority are exempt from reporting.

Health Risk Assessment

The Applicant provided an HRA that evaluated the potential human health risks posed by the ENGP's emissions of toxic air contaminants. The HRA was performed following the Office of Environmental Health Hazard Assessment (OEHHA) 2015 Risk Assessment Guidelines (OEHHA Guidance). The HRA estimated risks of cancer, non-cancer chronic exposure, and non-cancer acute exposure for residential, worker, and sensitive receptors. Health risk results for the maximally exposed individual resident (MEIR), maximally exposed individual worker (MEIW), and maximally exposed sensitive receptor (MESR) were compared to SCAQMD significance thresholds. Additionally, points of maximum impact (PMI) were evaluated for each health impact.

The HRA analysis included TAC emissions from operational activities including the MTU, PTU, RM, cooling tower, emergency generators, HCl scrubber, and fire pump. The Applicant used AERMOD to estimate ambient air concentrations at off-site receptors using a unit emission rate for each source group. Ambient air concentrations were estimated for the 1-hour and annual averaging periods, following OEHHA Guidance. The modeling included the same receptor grid evaluated in the ambient air quality analysis, with the addition of discrete sensitive receptor locations.

Risk calculations were performed using AERMOD output plot files and CARB's HARP2 risk calculation tool with the exposure assumptions shown in the table below. The following scenarios were analyzed in HARP2:

- Cancer and Non-cancer Chronic Risk
    - Scenario 1: PTU, RM, routine operation of the cooling tower with startups and shutdowns, emergency generators, fire pump, and HCl scrubber.
    - Scenario 2: Routine operation of the cooling tower without startups and shutdowns (i.e., 8,760 hours of operation), emergency generators, fire pump, and HCl scrubber.
- Non-cancer Acute Risk
    - Scenario 1: Routine operation of the cooling tower with startups and shutdowns, emergency generators, fire pump, and HCl scrubber
    - Scenario 2: MTU only

Table 9. Summary of HARP2 Exposure Options					
	Cancer Risk		**Chronic Risk**	**Acute Risk**	**Cancer Burden**
Receptor Type	Resident	Worker	N/A	N/A	Resident
Intake Rate Percentile	RMP using the Derived Method	OEHHA Derived Method	OEHHA Derived Method	N/A	RMP Using the Derived Method
Start Age	Third Trimester	16	N/A	N/A	Third Trimester
Exposure Duration	30 years	25 years	N/A	N/A	70 years
Exposure Pathways	Inhalation Soil Ingestion Dermal Absorption Mother's Milk Homegrown Produce Beef/Dairy (Farming) Pig/Chicken/ Egg (Farming)	Inhalation Soil Ingestion Dermal Absorption	Inhalation Soil Ingestion Dermal Absorption Mother's Milk Homegrown Produce Beef/Dairy (Farming) Pig/Chicken/ Egg (Farming)	Inhalation	Inhalation Soil Ingestion Dermal Absorption Mother's Milk Homegrown Produce Beef/Dairy (Farming) Pig/Chicken/ Egg (Farming)

The HARP2 outputs show that the cancer health risks at the MEIR, MEIW, and MESR are all below the SCAQMD significance threshold of 10 in a million-cancer risk. Cancer burden was estimated for census receptors within the 1-in-a-million 30-year residential cancer risk isopleth. The census population within the isopleth was multiplied by the 70-year residential cancer risk to calculate a cancer burden of less than 0.001, which is less than the SCAQMD's significance threshold of 0.5.

The non-cancer chronic and acute risk impacts are below the SCAQMD significance thresholds of chronic hazard index (HI) of 1.0 and acute HI of 1.0 at all locations except for the PMI and MEIW. Therefore, the ENGP triggers additional requirements for public notice under AB 2588. The ENGP also triggers the need for Best Available Control Technology for Toxics (TBACT) consistent with the permitting thresholds provided in CARB's Risk Management Guidance for Stationary Sources of Air Toxics. TBACT is defined in SCAQMD Rule 1401 as "the most stringent emissions limitation or control technique which (A) has been achieved in practice for such permit unit category or class of source; or (B) is any other emissions limitation or control technique, including process and equipment changes of basic and control equipment, found by the [Air District] to be technologically feasible for such class or category of sources, or for a specific source. The primary driver for the acute health risk impacts are particulate and H_2S emissions associated with the cooling tower operations. As discussed previously, the cooling tower will be equipped with BACT controls which are also expected to meet the definition of TBACT since they will control H_2S and particulate (toxic metal) emissions.

Table 10. Operational HRA Summary

Receptor Type	**Receptor No.**	**UTM E (m)**	**UTM N (m)**	**Cancer Risk (per million)**	**Chronic HI**	**Acute HI**
PMI	50 [a] 75 [b]	630,714.83 [a] 630,254.29 [b]	3,672,138.02 [a] 3,671,995.77 [b]	18.7	1.29	2.41
MEIR	5,729 [a] 5,724 [b]	638,180.33 [a] 629,090.70 [b]	3,672,664.25 [a] 3,671,844.15 [b]	0.46	0.03	0.96
MEIW	50 [a] 75 [b]	630,714.83 [a] 630,254.29 [b]	3,672,138.02 [a] 3,671,995.77 [b]	0.82	1.29	2.41
Maximally Exposed Sensitive Receptor	5,729 [a] 5,724 [b]	638,180.33 [a] 629,090.70 [b]	3,672,664.25 [a] 3,671,844.15 [b]	0.46	0.03	0.96

Notes:
[a] Receptor number and coordinates associated with cancer and chronic analyses.
[b] Receptor number and coordinates associated with acute analyses.

E = Easting
m = meters
N = Northing
UTM = Universal Transverse Mercator

Table 11. Operational HRA Summary - MTU				
Receptor Type	**Receptor No.**	**UTM E (m)**	**UTM N (m)**	**Acute HI**
PMI	1,910	630,675.00	3,672,450.00	3.70
MEIR	5,725	629,310.70	3,674,439.02	0.66
MEIW	1,910	630,675.00	3,672,450.00	3.70
Maximally Exposed Sensitive Receptor	5,725	629,310.70	3,674,439.02	0.66

Authority to Construct and Permit to Operate Conditions

A. General Conditions

1. The facility shall be constructed to operate in substantial compliance with the project description, and operating parameters of the Application dated April 24, 2023, and subsequent data submittals on June 12, 2023, October 4, 2023, November 10, 2023, and November 14, 2023, except as may be modified by more stringent requirements of law or these conditions.
2. Operation of all equipment shall be in compliance with all data and specifications submitted with the Application under which this permit is issued unless otherwise noted.
3. Operation of all equipment shall be in compliance with applicable ICAPCD Rules and Regulations.
4. This permit does not authorize the emissions of air contaminants in excess of those allowed by the USEPA (Title 40 of the Code of Federal Regulation [CFR]), the State of California (Division 26, Part 4, Chapter 3 of the Health & Safety Code), or the ICAPCD (Rules and Regulations).
5. This permit cannot be considered permission to violate applicable existing laws, regulations, rules or statues of other governmental agencies.
6. No air contaminant shall be released into the atmosphere which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such persons or the public or which cause or have a natural tendency to cause injury or damage to business or property.
7. All equipment shall be maintained in good operating conditions and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere.
8. Disturbances of soil related to any construction, demolition, excavation, or other earthmoving activities shall comply with the requirements for fugitive dust control stated in Air District Rule 801.
9. The Permittee shall prevent or cleanup any carry-out or track-out, as specified in Air District Rule 803.
10. The Permittee shall implement Best Available Control Measures (BACM) at any applicable open areas to control fugitive dust emissions, as specified in Air District Rule 804.
11. Any unpaved and paved road, and open areas subject to be disturbed by vehicle traffic shall comply with the requirements of Air District Rule 805 for fugitive dust control.
12. The Permittee shall not release or discharge into the atmosphere any air contaminant for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann Chart 1 or 20% opacity.
13. The Permittee shall maintain all unpaved haul/access roads and parking areas within the facility with a dust suppression system consisting of gravel, crushed/recycled asphalt, water suppression, or other forms of physical stabilization.

14. The emissions of any regulated pollutant, as defined pursuant to 40 CFR 70.2, shall be less than the major source threshold values listed in Air District Rule 900, Section B.23.
15. The emissions of any single hazardous air pollutant, as defined pursuant to Section 112(b) of the 1990 Clean Air Act shall be less than 10 tons per year. Total combined emissions of all hazardous air pollutants, as defined pursuant to Section 112(b) of the 1990 Clean Air Act, shall be less than 25 tons per year.

B. Facility Emissions and Operational Limits

1. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP facility during routine power generation, when all abatement systems are operating.

Pollutant	**Emission Limits (lb/hr)**	**Emission Limits (lb/day)**
Hydrogen Sulfide (H_2S)	2.01	48.24

2. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP during times in which the sparger abatement system is being bypassed or during breakdown, which is limited to a maximum of 200 hours per year.

Pollutant	**Emission Limits (lb/hr)**	**Emission Limits (lb/day)**
Hydrogen Sulfide (H_2S)	81.2	1,948.8

3. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP during times in which the Ox-Box abatement system is being bypassed or during breakdown, which is limited to a maximum of 200 hours per year.

Pollutant	**Emission Limits (lb/hr)**	**Emission Limits (lb/day)**
Hydrogen Sulfide (H_2S)	54.8	1,315.2

4. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP facility during commissioning:

Pollutant	**Emission Limits (lb/hr)**	**Emission Limits (lb/day)**
Hydrogen Sulfide (H_2S)	134	3,216

5. The following emissions limits shall not be exceeded by the Permittee at the ENGP facility during well flow back conditions:

Pollutant	Per Well	Facility-Wide
	Emission Limits (lb/hr)	Emission Limits (lb/day)
Hydrogen Sulfide (H_2S)	9.95	238.8

6. The following emissions limits shall not be exceeded by the Permittee at the ENGP facility during well testing:

Pollutant	Per Well	Facility-Wide
	Emission Limits (lb/hr)	Emission Limits (lb/day)
Hydrogen Sulfide (H_2S)	40.4	969.6

7. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP facility during cold and warm startups, which are limited to a maximum of 200 hours per year and 400 hours per year, respectively:

Pollutant	Emission Limits (lb/hr)	Emission Limits (lb/day)
Hydrogen Sulfide (H_2S)	134	3,216

8. The following facility-wide emissions limits shall not be exceeded by the Permittee at the ENGP facility during shutdown, which is limited to a maximum of 198 hours per year.

Pollutant	Emission Limits (lb/hr)	Emission Limits (lb/day)
Hydrogen Sulfide (H_2S)	152	3,648

9. The following facility-wide emissions and throughput limits shall not be exceeded by the Permittee at the ENGP facility during HCl scrubber and tank operation.

Pollutant	Emission Limits (lb/hr)	Emission Limits (lb/day)	Throughput Limits (gal/yr)
Hydrogen Chloride (HCl)	0.11	2.75	52,560,000

10. The total facility-wide emissions, including maintenance/bypass of emissions control systems, startups, shutdowns, maintenance of geothermal wells and normal operations, shall not exceed the following annual rates:

   a. Hydrogen sulfide emissions shall be limited to 186 tons in the first production year, which includes well testing and commissioning activities.

b. Hydrogen sulfide emissions shall be limited to 64.9 tons per year, for each subsequent year of production.

c. PM_{10} emissions shall be limited to 14.9 tons per year.

11. The Ox-Box and sparger abatement systems shall follow the below operating conditions:

a. The Permittee shall engage control equipment upon plant startup and shall utilize controls as long as practicable during periods of malfunction. Use of the controls will establish an affirmative defense to any excess emissions during startup, shutdown, and malfunction if the control equipment is maintained and operated in a manner consistent with good practice for minimizing emissions.

b. The Permittee shall operate the Ox-Box and sparger abatement systems for hydrogen sulfide control to achieve compliance with the hydrogen sulfide emission limits.

12. The Permittee shall install, operate, and maintain the listed Ox-Box and sparger abatement system (utilizing the oxidizing biocide [BIOX] process) at all times the production wells are in use, except for the following:

a. When control equipment or upstream equipment maintenance requires bypassing either the Ox-Box system or sparger system, bypass of each abatement system will be limited to a maximum of 200 hours per year.

13. The permittee shall limit the flow-back duration for new wells to twenty-four (24) hours per well and the well testing duration for new wells to 240 hours per well, with the permittee using best available control methods to minimize fugitive emissions and venting to the atmosphere.

C. Cooling Tower

1. The ENGP cooling tower shall not exceed the following PM_{10} emissions limits:

Pollutant	Emission Limits (lb/hr)	Emission Limits (lb/day)
PM_{10}	3.37	80.88

2. The water circulated in the ENGP cooling tower shall not exceed the following concentration limit for TDS:

Pollutant	Concentration Limits (ppmv)
TDS	9,000

3. The Permittee shall control PM_{10} emissions by installing high efficiency drift eliminators that comply with the drift loss specs (0.0005%) claimed by the Permittee.

4. The Permittee shall maintain the drift eliminators of the cooling tower in good working order at all times to perform in accordance with the manufacturer specifications.

5. Testing of emissions from the Ox-Box system and sparger system will be conducted at the shrouds of the cooling tower during normal operation.

D. Emergency Units

1. Each listed emergency generator shall be restricted to operate a total of fifty (50) hours per year for maintenance and testing purposes.
2. The listed emergency fire pump shall be restricted to operate a total of fifty (50) hours per year for maintenance and testing purposes and to comply with the requirements of the National Fire Protection Association (NFPA) 25.
3. Operation of the listed emergency generators for other than testing and maintenance purposes shall be limited to providing backup power, and in each instance, documented to the satisfaction of the ICAPCD.
4. All internal combustion engines shall not discharge into the atmosphere any visible air contaminant, other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour, which is 20% opacity or greater.
5. Each listed emergency unit shall be equipped with a non-resettable hour meter which must be kept in proper working condition at all times.
6. The diesel engine of each listed emergency unit shall be fueled only with one or a combination of the following, (per Airborne Toxic Control Measure for Stationary Compression Ignition [CI] Engines § 93115.5 (a)):
   a. CARB diesel fuel; or
   b. an alternative diesel fuel, such as biodiesel or a biodiesel blend that does meet the definition of CARB diesel fuel; or
   c. any alternative diesel fuel that meets the requirements of the Verification Procedure; or
   d. CARB diesel fuel used with fuel additives that meets the requirements of the Verification Procedure.
7. The Permittee shall maintain an operation engine log onsite for each listed emergency unit. The Permittee shall maintain all required records for a minimum of two (2) calendar years and make them available to the ICAPCD upon request. The log(s) shall include the following for each unit:
   a. Engine manufacturer name, model number, brake horsepower output rating, and type of fuel combusted;
   b. A manual of recommended maintenance as provided by the engine manufacturer or other maintenance procedure as approved in writing by the APCO;
   c. Record of routine engine maintenance, including date(s) and type of maintenance performed;
   d. A specific emission inspection procedure, with an inspection schedule, to ensure that the engine is operated in continual compliance with Air District Rule 400.3. Inspections shall be

conducted every quarter or after every 2,000 hours of engine operation. In no event shall the frequency of inspections be less than once per year.

e. For each emergency unit, the total daily recorded hours of operation for maintenance and testing purposes.

f. For each emergency unit, the total daily recorded hours of operation for emergency events.

8. The listed three emergency generators, with Kohler Engines Model KD83V16, shall be limited to the following emission limits:

   a. 4.8 lbs/hr of NOx

   b. 25.1 lb/hr of CO

   c. 0.21 lb/hr of PM_{10}.

9. The Permittee shall conduct an initial source test for each listed emergency generator to demonstrate compliance with the emission limits of Condition D.8 within 60 days of start-up and once every 36 months thereafter. All emission rates shall be based on an hourly average, and the NOx emissions concentration shall be calculated as an average of three test runs.

10. The frequency of compliance testing required per Condition D.9 may be extended to not less than every 60 months per emergency generator, provided that the unit operated less than 500 hours per 12-month period (as demonstrated by operating logs) and which emitted less than 5 tons of NOx per 12-month period. This period may be extended if the Permittee can prove that the unit(s) did not operate during the calendar year.

11. The listed emergency generators shall each be source tested at no less than 80% of its total horsepower rating to determine compliance with the emission limits of Condition D.8. If the permittee demonstrates to the satisfaction to the APCO that a listed unit cannot operate at 80% capacity, then the source test shall be performed at the highest achievable continuous power rating. Compliance with the NOx emission limits shall be determined by using CARB Method 100, ISO Method 8178, or US EPA Method 7E. Oxygen Content shall be determined by using CARB Method 100, ISO Method 8178, or US EPA Method 3A. Compliance with the CO emission limits shall be determined by using CARB Method 100, ISO Method 8178, or US EPA Method 10.

12. The source test protocol for each required test of Condition D.9 shall be submitted to the ICAPCD for approval 30 days prior to commencing testing. Additionally, the permittee shall notify the ICAPCD at least seven (7) days prior to a scheduled source test with the exact date and time of the source test. The source test results shall be submitted to the ICAPCD within 60 days of the test being completed.

13. The Permittee shall ensure that the ammonia slip emissions from the SCR systems abating the emergency generators do not exceed 5 ppmv, dry @ 15% O_2. The APCO may request source testing by the Permittee to demonstrate compliance with this emission limit.

14. Permittee shall maintain all records for the listed emergency combustion units for a minimum of two (2) calendar years. These records shall be maintained with the unit or at the company's office and shall be made available to the District upon request.

E. HCl Scrubber

1. The HCl storage tank shall be controlled by a scrubber with a minimum control efficiency of 99% for HCl emissions.
2. The Permittee shall conduct a source test of the HCl scrubber within ninety (90) days of start-up of the power plant and every three years thereafter or sooner if requested by the APCO. The source test shall use EPA methods or ICAPCD-approved equivalent (for hydrogen chloride, ARB Method 421). Testing protocol(s) shall be submitted to the District for approval 30 days prior to source testing being conducted. Additionally, the permittee shall notify the ICAPCD at least seven (7) days prior to a scheduled source test with the exact date and time of the source test. The source test results shall be submitted to the ICAPCD within 60 days of the test being completed.

F. Monitoring Program

1. The Permittee shall monitor the H_2S concentration (ppm) and mass flow rate (lb/hr) at the inlet of the Ox-Box on a weekly basis.
2. The Permittee shall monitor the H_2S concentration (ppm) and mass flow rate (lb/hr) at the inlet of the sparger abatement system at least once a week.
3. The Permittee shall measure the H_2S concentration (ppm) and mass flow rate (lb/hr) at the exhaust of each cooling tower shroud on a weekly basis. Each week, the outlet mass flow and the inlet mass flow (determined in Conditions F.1 and F.2) will be used to calculate the overall abatement efficiency of the Ox-Box and sparger abatement systems.
4. Prior to operations, the Permittee shall submit to the APCO a compliance plan that meets the requirements of Section D of ICAPCD Rule 1003. This plan must be maintained onsite for at least two years and available to the Air District upon request.
5. The Permittee shall inspect on a yearly basis the cooling tower drift eliminators to ensure that every cooling tower cell has the complete set of panels of drift eliminators, and replace those that are damaged. As a part of this annual inspection, the Permittee shall conduct an inventory survey of the drift eliminators to ensure that the equipment is operating to specifications (i.e., maximum drift loss of 0.0005%).
6. The Permittee, within 30 days of the end of each month, shall calculate the previous month's total H_2S emissions for the ENGP facility, and add it to the preceding eleven months to get a rolling twelve-month total. These calculations shall be maintained in a log and made available to the ICAPCD upon inspection in order to demonstrate compliance with the emissions limit set forth in Condition B.10a and B.10b. In addition, a third-party contractor shall conduct testing and analyze H_2S emissions for the ENGP facility at least once per year.
7. The Permittee, within 30 days of the end of each month, shall calculate the previous month's total PM_{10} emissions for the ENGP facility, based on methods in Condition H.4 and add it to the preceding eleven months to get a twelve-month rolling total. These calculations shall be maintained in a log and made available to the ICAPCD upon inspection in order to demonstrate compliance with the emissions limits set forth in Condition B.10c and Condition C.1. In addition, a third-party contractor shall conduct testing and analyze PM_{10} emissions for the ENGF, according to the method in Condition H.4, at least once per year.

8. In accordance with Condition H.6, the Permittee shall conduct a cooling tower source test of the ENGP facility within ninety (90) days of start-up and every four years thereafter or sooner if requested by the APCO to ensure compliance.

9. For maintenance of the Ox-Box and sparger abatement systems and associated upstream equipment, the Permittee shall maintain an up-to-date operational log, keeping records for a minimum of the three previous years, to track periods of maintenance for each system.

10. The Permittee shall maintain an up-to-date operating log of facility startup and load rejection events, keeping records for a minimum of the three previous years.

11. The Permittee shall maintain an up-to-date operating log of geothermal wells maintenance venting, keeping records for a minimum of the three previous years, to track periods of venting from maintenance of each of the facility's wells.

12. The Permittee shall analyze H_2S emissions using Tracer Enthalpy Test Procedures during well flow back to demonstrate compliance with Condition B.5.

13. The Permittee, when requested by the APCO, shall provide records, collect samples or gather other required information that will enable the APCO to determine compliance status (Rule 109). The ICAPCD may at any time elect to have itself or a third-party source test contractor or agency take samples and analyze for concentration and emission rates of any pollutant.

14. All the source testing, sampling, analysis, and reporting cost shall be borne by the Permittee.

15. Upon proper notification, the ICAPCD or its designee shall have the right to enter to inspect and take samples from the emission sources at the ENGP facility.

G. Notification Requirements

1. Breakdowns:

   a. The Permittee shall notify the ICAPCD (per Rule 111) of any upset conditions or breakdown at the ENGP facility which causes a violation of emission limitations prescribed by ICAPCD Rules and Regulations, or by State law. The Air District shall be notified no later than two (2) hours after its detection. The completion of corrective measures or the shutdown of emitting equipment is required within 24 hours of occurrence of a breakdown condition, unless a Variance has been obtained. Venting due to plant startup, load rejection, or well testing is not considered a breakdown condition.

   b. In the event of a breakdown, Permittee shall submit, within 10 days after a breakdown occurrence has been corrected, a written report to the APCO which includes: a) a statement that the occurrence has been corrected, b) the reason(s) or cause(s) of the occurrence, c) a description of the corrective measures undertaken, and d) the type of emission(s) and estimated quantity of each type of emissions caused by the occurrence.

2. Maintenance:

   a. The Permittee shall notify the ICAPCD at least 24 hours in advance before any scheduled maintenance is performed on the Ox-Box system, sparger system, or associated upstream equipment.

b. The Permittee shall notify the ICAPCD within at least 2 hours after the start of any unscheduled maintenance of the Ox-Box system, sparger system, or associated upstream equipment.

c. The Permittee shall notify the ICAPCD at least 24 hours in advance before any scheduled maintenance of geothermal wells.

d. The Permittee shall notify the ICAPCD within at least 2 hours after the start of any unscheduled maintenance of geothermal wells.

e. The Permittee shall notify the ICAPCD of any material physical change, change in method of operation, or addition to the facility that results in a net emission increase or decrease of any regulated pollutant.

H. Analyses

1. The Permittee shall conduct a weekly analysis of the H_2S content in the condensate at the inlet of the Ox-Box in accordance with Condition F.1. Each laboratory analysis shall use USEPA approved methods or ICAPCD approved equivalents.

2. The Permittee shall conduct a weekly analysis of the H_2S content in the non-condensable gases at the inlet of the sparger abatement system in accordance with Condition F.2. Each laboratory analysis shall use USEPA approved methods or ICAPCD approved equivalents.

3. The Permittee shall conduct weekly analysis of the H_2S concentration (ppm) and mass flowrate (lb/hr) at the exhaust of each cooling tower shroud in accordance with Condition F.3. Laboratory analysis shall use USEPA approved methods or ICAPCD approved equivalents.

4. The Permittee shall conduct monthly testing of the recirculating water TDS levels for the cooling tower at ENGP to verify compliance with the cooling tower PM_{10} emission limit in Condition C.1 and TDS limit in Condition C.2.

5. In accordance with Condition E.2, the Permittee shall conduct a source test of the ENGP facility within ninety (90) days of start-up and every three years thereafter or sooner if requested by the APCO to ensure compliance. The source testing shall be witnessed by APCD Staff, with all analytical results made available at the facility for inspection. The source test protocol shall be submitted for APCD approval 30 days prior to source testing being conducted, including testing described in Condition E.2 above. Laboratory analysis shall use the EPA approved methods or an ICAPCD approved equivalent for the following:

    a. Controlled emissions from the HCl scrubber for hydrogen chloride.

6. In accordance with Condition F.8, the Permittee shall conduct a source test of the ENGP facility within ninety (90) days of start-up and every four years thereafter or sooner if requested by the APCO to ensure compliance. The source testing shall be witnessed by APCD Staff, with all analytical results made available at the facility for inspection. The source test protocol shall be submitted for APCD approval 30 days prior to source testing being conducted, including testing described in Condition F.8 above. Laboratory analysis shall use the EPA approved methods or an ICAPCD approved equivalent for the following:

a. Hot well condensate from the turbine condensers and cooling tower blow down for ammonia, arsenic, benzene, cadmium, chromium, copper, hydrogen sulfide, lead, manganese, mercury, nickel, radon, selenium, and zinc.

b. Of the non-condensable gases vented for: hydrogen sulfide, ammonia, arsenic, mercury, radon, benzene, toluene, and xylene.

I. Reports

1. Permittee shall submit to the ICAPCD a monthly report within 30 days of the preceding month that includes the following:

   a. The combined Ox-Box and sparger abatement efficiency of H_2S, based on the analysis of:

      1) The H_2S concentration in the condensate at the inlet of the Ox-Box in ppm and H_2S mass flow in lb/hr per Condition H.1;

      2) The H_2S concentration in the non-condensable gases at the inlet of the sparger in ppm and H_2S mass flow in lb/hr per Condition H.2; and

      3) The analysis of the H_2S concentration (ppm) and mass flow rate (lb/hr) at the exhaust of each cooling tower shroud per Condition H.3.

   b. The overall H_2S removal efficiency by the air abatement systems, for the Ox-Box and sparger abatement systems combined (percent removal based on mass flow rate).

   c. The monthly number of hours during which the sparger abatement system was bypassed or broken down, and the year-to-date total, to demonstrate compliance with Condition B.2.

   d. The monthly number of hours during which the Ox-Box abatement system was bypassed or broken down, and the year-to-date total, to demonstrate compliance with Condition B.3.

   e. The monthly number of hours for facility cold startups, and the year-to-date total, to demonstrate compliance with Condition B.7.

   f. The monthly number of hours for facility warm startups, and the year-to-date total, to demonstrate compliance with Condition B.7.

   g. The monthly number of facility shutdown hours, and the year-to-date total, to demonstrate compliance with Condition B.8.

   h. The monthly throughput of hydrogen chloride through the HCl storage tank, and the year-to-date total, to demonstrate compliance with Condition B.9.

   i. The monthly number of hours per well for flow back, to demonstrate compliance with Condition B.13.

   j. The results of H_2S emissions analyses conducted during flow back in that month, to demonstrate compliance with Conditions B.5.

2. Permittee shall submit to the ICAPCD a report with the results of the cooling tower drift eliminators survey within sixty (60) days of the completion of the survey, in accordance with Condition F.5 of this Permit.

3. Permittee shall submit to the ICAPCD a report containing the HCl scrubber source testing pursuant to Conditions E.2 and H.5. The report shall be submitted 60 days after each source testing completion.

4. Permittee shall submit to the ICAPCD a report containing the cooling tower source testing pursuant to Conditions F.8 and H.6. The report shall be submitted 60 days after each source testing completion.

5. Permittee shall submit to the ICAPCD an annual report by the end of February of each operating year. This report shall include the following items:

   a. Total tons of H_2S emissions for the reporting year.

   b. Types and quantities of cooling water additives.

   c. Gross megawatts produced and net electrical megawatt-hours sold for the reporting year.

   d. Results from each monthly test of the recirculating water total dissolved solids levels for the cooling tower, per Condition H.4.

   e. The monthly fuel consumption, hours operated per month for maintenance and/or testing, and hours operated per month for emergency events for each listed emergency combustion unit.

   f. The status of all active wells associated with the facility used for production or injection during the reporting year. For each well include the total days of rig activity (work over, clean out, or drilling) and the total hours of venting to the atmosphere (from test units).

   g. The total annual number of hours during which the sparger abatement system was bypassed or broken down.

   h. The total annual number of hours during which the Ox-Box abatement system was bypassed or broken down.

   i. The total annual number of hours for facility cold startups.

   j. The total annual number of hours for facility warm startups.

   k. The total annual number of facility shutdown hours.

   l. The total annual throughput of hydrogen chloride through the HCl storage tank.

Equipment/Source List

Geothermal Power Plant

(1) Elmore North Geothermal Power Plant, with a capacity of approximately 157 MW gross (approximately 140 MW net).

Emergency Combustion Units

(1) Fire Pump, driven by a Clarke Model JU6H-UFADP0 diesel engine, with a rating of 316 bhp or equivalent as approved by the APCO.

(3) Standby Power Generators, 3,250 kW, driven by a Kohler Model KD83V16 diesel engine, with a rating of 4,680 bhp or equivalent as approved by the APCO.

Abatement Equipment

(1) Biological Oxidizer Box (Ox-Box), including a trickle block, splash fill, or equivalent packaging.

(1) Sparger Abatement System, utilizing oxidizing biocide (BIOX), consisting of distribution pipes with bubble diffusers/nozzles in the cooling tower for the abatement of hydrogen sulfide emissions in the non-condensable gases.

(1) Hydrochloric acid (HCl) scrubber

Cooling Tower

(1) Cooling Tower. Model TBD, consisting of fourteen cells, equipped with high-efficiency drift eliminators (0.0005%).

Hydrogen Chloride Dosing System

(1) 20,000-gallon HCl storage tank and dosing system.

Geothermal Wells

(9) Production Wells, named as follows: RH-01, RH-02, RH-03, RH-04, RH-05, RH-06, RH-07, RH-08, and RH-09.

(8) Injection Wells (Brine), named as follows: RHI-21, RHI-22, RHI-23, RHI-24, RHI-25, RHI-26, RHI-28, and RHI-29.

(2) Injection Wells (Condensate), named as follows: RHC-101 and RHC-103.

(1) Injection Well (Aerated), named RHA-102.