SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Preliminary Draft Staff Report
Proposed Amended Rule 1148.1 – Oil and Gas Production Wells

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EXECUTIVE SUMMARY

South Coast AQMD Rule 1148.1 – *Oil and Gas Production Wells* (Rule 1148.1) applies to approximately 330 onshore oil or gas well facilities that conduct operations including drilling, well completion, well rework, and well injection activities. Rule requirements reduce VOC emissions from the wellheads and the well cellars through inspection and maintenance, and control of produced gas emissions. The rule also establishes work practices and odor mitigation procedures. In response to concerns raised by Assembly Bill (AB) 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area and the 2022 Air Quality Management Plan Control Measure FUG-01: Improved Leak Detection and Repair, Proposed Amended Rule (PAR) 1148.1 will further reduce and control VOC emissions. PAR 1148.1 will: 1) add new definitions to further clarify the amendments being proposed, 2) require the use of enhanced leak detection technology, 3) require equipment that uses produced gas to meet specific NOx limits and to verify compliance via source tests, 4) require workover rigs to use Tier 4 Final diesel engines, 5) ban the use of odorants that are used to mask odors emanating from oil production sites, and 6) update signage requirements. Additional minor changes to rule language will be made for consistency and clarity.

CHAPTER 1: BACKGROUND

INTRODUCTION

BACKGROUND

AFFECTED FACILITIES

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INTRODUCTION

Rule 1148.1 – *Oil and Gas Production Wells* requires operators of oil and gas wells to reduce emissions of volatile organic compounds (VOCs), toxic air contaminants (TAC) emissions and Total Organic Compounds (TOC) from the operation of wellheads, well cellars, and the handling of produced gas at oil and gas production facilities. Well activity occurs at multiple sites throughout the South Coast AQMD and may be found near residential communities as shown in Figure 1.1.

Figure 1.1 – Example of Urban Oil Well

Concerns have been raised by AB 617 communities located in the Wilmington, Carson, West Long Beach (WCWLB) area and South Los Angeles (SLA) area about the need for additional, timely and reliable requirements to further control VOC emissions coming from oil and gas production facilities. In response, staff proposes to modify requirements in Rule 1148.1 to add the use of enhanced leak detection technology, require Tier 4 Final diesel engines in the use of workover rigs engaged in general maintenance activities, and source test requirements for stationary equipment that uses produced gas to verify emission limits. Staff also proposes to ban the use of odorants used to mask odors and update signage requirements. Additional definitions and minor changes to rule language are made for consistency and clarity.

REGULATORY BACKGROUND

Rule 1148.1 was adopted on March 5, 2004, to implement Control Measure FUG-05 of the 2003 AQMP by reducing VOC emissions from the wellheads and the well cellars located at oil and gas production facilities through increased inspection and maintenance, and control of produced gas emissions, with additional regulatory considerations when located within 100 meters to sensitive receptors. See Figure 1.2 for an example of wellheads inside a well cellar.

Figure 1.2 – Example of Wellheads Inside a Well Cellar

Rule 1148.1 was amended on September 4, 2015 to minimize environmental impacts on neighboring communities and sensitive receptors from ongoing operations, including well stimulation techniques such as hydraulic fracturing. Between 2010 and 2014, operations at an urban oil and gas production facility were the subject of numerous public complaints and received multiple Notices of Violations (NOV) from the South Coast AQMD. The amendment focused on improving work practices and established odor mitigation procedures.

AB 617 and Concerns with Oil and Gas Well Activities

In 2017, Governor Brown signed AB 617 (C. Garcia, Chapter 136, Statutes of 2017) to develop a new community-focused program to potentially reduce exposure to air pollution and preserve public health. AB 617 directed the California Air Resources Board (CARB) and all local air districts, including the South Coast AQMD, to enact measures to protect communities disproportionally impacted by air pollution. On September 27, 2018, CARB designated 10 communities across the state to implement community plans for the first year of the AB 617 program. Local air districts were tasked with developing and implementing community emissions reduction and community air monitoring plans in partnership with residents and community stakeholders. The Community Air Monitoring Plan (CAMP) includes actions to enhance the understanding of air pollution in the designated communities and to support effective implementation of the Community Emissions Reduction Plan (CERP). A CERP provides a blueprint for achieving air pollution emission and exposure reductions, addressing the community's highest air quality priorities. The CERP includes actions to reduce emissions and/or exposures in partnership with community stakeholders.

During their CERP development process, the WCWLB and SLA communities raised numerous concerns related to oil and gas well activity and current South Coast AQMD rules.

The CERP for WCWLB listed four main air quality priorities related to oil drilling and production. These priorities focused on:

- The need for near-facility air measurements and inspections to address leaks and odors from oil drilling and production;
- Fenceline air monitoring;
- Vapor recovery systems and leak detection technologies; and
- The use of lower or zero-emission equipment for on-site operations.

The CERP for SLA also listed multiple priorities related to oil drilling and production. These priorities focused on:

- Identification of potential elevated emissions through air measurement surveys around oil drilling sites;
- Determination of which oil well sites and activities may require additional monitoring;
- Explore limiting/eliminating odorant use;
- Explore requirements for lower emission or zero-emission equipment;
- Reduction emissions and exposure to oil and gas operations through rule amendments to the Rule 1148 Series;
- Incentive funding opportunities for best management practices and/or installation of emission reduction technologies at oil and gas facilities.

Note that some other community concerns have been addressed in the February 2023 amendment to *Rule 1148.2 – Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers* (Rule 1148.2) such as providing notifications for activities such as acidizing of water injection wells. In addition, Rule 1148.2 has requirements for mailers to be sent out to sensitive receptors within 1,500 feet of an oil and gas or injection well prior to the commencement of an acidizing event.

AFFECTED FACILITIES

Proposed Amended Rule 1148.1 affects any operator of an oil or gas production facility located within the jurisdiction of the South Coast AQMD and its operation and maintenance of wellheads, well cellars, and the handling of produced gas. There are approximately three hundred and thirty facilities potentially affected by this amendment.

PUBLIC PROCESS

The development of PAR 1148.1 was conducted through a public process. Three Working Group Meetings were held on: April 20, 2023, September 14, 2023, and December 14, 2023. In addition, staff participated in AB 617 meetings to notify and update stakeholders on the rule development process. Stakeholders include representatives from the community, environmental organizations, industry representatives, and government agencies. Staff also met individually with industry stakeholders and visited sites affected by the rule development process. Working group meeting notices were provided to operators, suppliers and participants of AB 617 meetings that signed up for notifications of AB 617 updates or oil and gas well rule development.

CHAPTER 2: BARCT ASSESSMENT

INTRODUCTION

As part of the rule development process, staff conducted a Best Available Retrofit Control Technology (BARCT) assessment of equipment subject to PAR 1148.1. The purpose of a BARCT assessment is to identify potential emission reductions from specific equipment and to establish an emission limit consistent with state law.

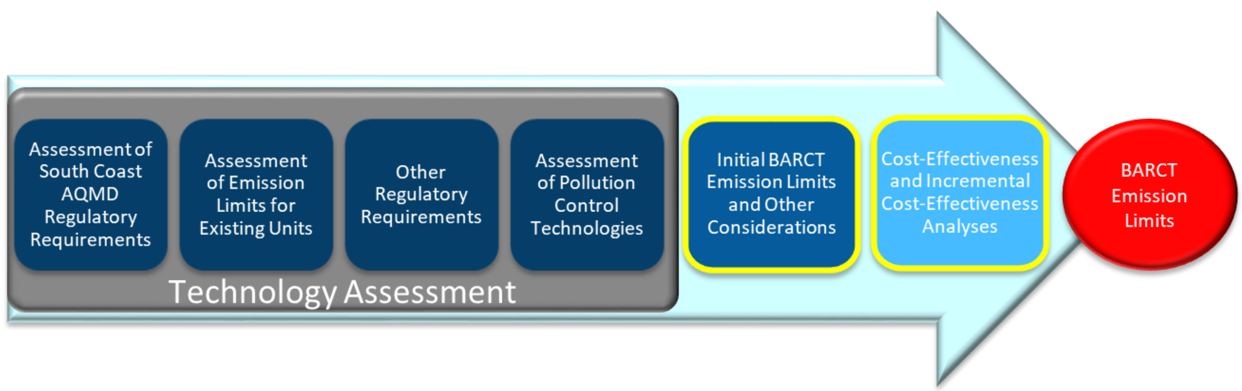
Under California Health and Safety Code § 40406, BARCT is defined as:

> "… an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source."

The BARCT assessment for this rule development consisted of a multi-step analysis. The first four steps represent the technology assessment. First, staff evaluated current South Coast AQMD regulatory requirements with an applicability to this rule development. Second, staff then assessed emission limits for existing units. Third, staff next surveyed other air districts and agencies outside of the South Coast AQMD's jurisdiction to identify emission limits that exist for similar equipment. In the final step of the technology assessment, staff assessed pollution control technologies to determine what degree of reduction could be achievable for the affected sources. Based on the technology assessment, initial emission limits and other considerations were proposed.

Once initial emission limits have been proposed, staff then calculated the cost-effectiveness of the proposals. The calculations consider the cost to meet the initial BARCT emission limit and the emission reductions that would occur from implementing technology that could meet the initial BARCT emission limit. An incremental cost-effectiveness analysis is conducted if multiple cost-effective control technology options are identified. Options are compared to determine costs of emission reductions. Based on the evaluation of the information, BARCT emission limits are recommended. See Figure 2-1 below for a graphical representation of the BARCT assessment process.

Figure 2.1 – BARCT Assessment Process



BARCT ANALYSIS APPROACH

In this rulemaking effort, staff is considering the following proposals to be incorporated into the rule:

(1) Adding the use of enhanced monitoring and leak detection techniques
(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps
(3) Establishing emission limits for stationary gas turbines using produced gas for fuel
(4) Requiring electrification or the use of cleaner engines for workover rigs

(1) Adding the use of enhanced monitoring and leak detection techniques

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1 (i)(1) requires the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to inspect components and equipment regulated by the rule. Typically, the analyzer used is a Toxic Vapor Analyzer (TVA) (See Figure 2.2). A TVA is capable of measuring a variety of organic vapors using flame ionization detection (FID) technology and it provides a concentration value of the organic vapor.

Figure 2.2 – Example of a Toxic Vapor Analyzer

Other South Coast AQMD Rules also require the use of an appropriate analyzer calibrated with methane per U.S. EPA Reference Method 21 to conduct inspections including but not limited to: Rule 1149 – *Storage Tank and Pipeline Cleaning and Degassing*; Rule 1173 – *Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants*; Rule 1176 – *VOC Emissions from Wastewater Systems*; and Rule 1178 – *Further Reductions for VOC Emissions from Storage Tanks at Petroleum Facilities*.

In September 2023, Rule 1178 was amended to include optical gas imaging (OGI) inspections for equipment subject to the rule.

- *Assessment of Emission Limits of Existing Units*

The use of OGI equipment does not have an emission limit relevant to this analysis. As such, no assessment of emission limits of existing units is required.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that the use of enhanced monitoring techniques utilizing OGI was limited.

San Joaquin Valley Air Pollution Control District (SJVAPCD) Rule 4409 – *Components at Light Crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities*, subsection 6.3, after June 30, 2024, requires that all leaks detected with the use of an OGI instrument shall be measured using U.S. EPA Reference Method 21 within two calendar days of initial OGI leak detection or within 14 calendar days of initial OGI leak detection of an inaccessible or unsafe to monitor component to determine compliance with the leak thresholds and repair timeframes specified in the rule[1].

Figure 2.3 – Example of an OGI camera

Under Colorado Air Quality Control Commission Regulation Number 7 – *Control of Emissions from Oil and Gas Emissions Operations*, the use of an OGI camera can be utilized as part of an approved leak detection and repair plan[2]. Leak detection thresholds are quantified using a TVA or equivalent device.

- *Assessment of Pollution Control Technologies*

OGI equipment does not control pollution directly but is a tool that can be used to identify emissions. As such, no assessment of pollution control technology is required for adding the use of enhanced monitoring and leak detection techniques. However, a discussion on current enhanced monitoring and leak detection technologies is included.

<u>Optical Gas Imaging</u>

An optical gas imaging camera uses infrared technology capable of visualizing vapors. OGI cameras have different detectors capable of visualizing a variety of gas wavelengths. VOC wavelengths are in the 3.2-3.4 micrometer waveband.

Figure 2.4 – OGI Camera Imaging

The cameras are widely used as a screening tool for leak detection purposes and have continuous monitoring capability. Handheld OGI cameras are used widely by leak detection service providers as well as facilities for periodic monitoring.

[1] Reference: https://ww2.valleyair.org/media/z11dynbx/rule-4409.pdf, page 4409-21.
[2] Reference: https://drive.google.com/file/d/1P6pRmNYx5KwEK6qDReYFL11-K-URI33J/view, page 36.

Open Path Sensors

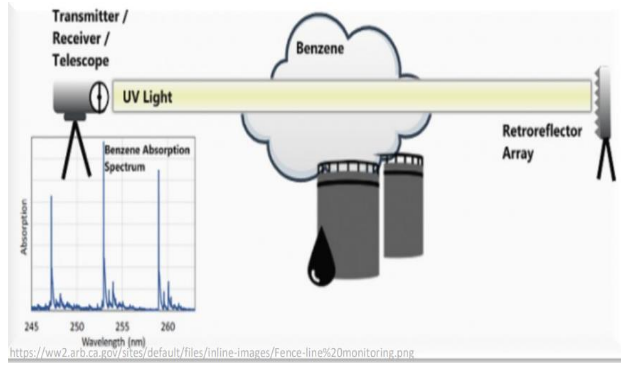


Figure 2.5 – Example of Open Path Technology

Open path detection devices emit beams that detect VOCs (See Figure 2.5). For VOC to be detected with an open path device, the VOCs must contact the beam. Open path detection devices can detect gas concentrations in the parts per billion range and from distances as far as 300 meters away from a source, with some models advertised as having a range of 1,000 meters. One open path device can cover multiple paths. Open path devices can detect small concentrations of VOC in the ppb range and can also speciate VOC. A significant limitation to leak detection of these devices is the requirement for VOCs to contact the emitted beam. This provides a chance for VOCs to go undetected if travelling on a path that does not intercept the beam. Another drawback to open path detection is the dilution factor. VOCs originating from a tank may need to travel hundreds of feet before contacting the emitted beam. The concentration of VOC may dilute so significantly that VOCs are undetectable by the time the VOCs reach the emitted beam.

Fixed Gas Sensors


Figure 2.6 – Example of a Fixed Gas Sensor

Fixed gas sensors have the capability to continuously monitor for VOC emissions and are installed as fixed applications (See Figure 2.6). Concentrations of VOC detected with fixed gas sensors are in the ppb/ppm range depending on the sensor and have a maximum detection range of about 50-100 ppm. Like open path devices, gas sensors can only detect emissions when VOCs contact the fixed sensor. Leaks from a source must be significant to be detected by a fixed gas sensor due to the dilution factor. According to one supplier, it is estimated that a leak with a concentration of 72,000 ppm is detectable by a gas sensor 100 feet away. A leak with a concentration of 18,000 ppm is detectable by a gas sensor 50 feet away.

(2) Establishing emission limits for internal combustion engines used to operate wellhead pumps

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, Rule 1148.1 does not have any emission limits for engines operated at facilities subject to this rule. However, other South Coast AQMD rules do regulate internal combustion engines. South Coast AQMD Rules 1110.2 – *Emissions from Gaseous- and Liquid-Fueled Engines* and 1470 – *Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines* regulate emissions from internal combustion engines that are rated greater than 50 bhp. In addition, stationary engines that are greater than 50 bhp are required to be permitted by the South Coast AQMD. Some engines, however, that are less than 50 bhp but are operated by facilities subject to the South Coast AQMD Regional Clean Air Incentives Market (RECLAIM) program are also subject to permitting requirements. Portable engines that are greater than 50 bhp are required to be either registered by the California Air Resources Board (CARB) through their Portable Equipment Registration Program (PERP) or permitted by the South Coast AQMD.

- *Assessment of Emission Limits of Existing Units*


Figure 2.7 – Example of an ICE

During the rule development process, staff visited multiple sites where internal combustion engines were observed to be operating wellhead pumps (See Figure 2.7). The sites were not part of the RECLAIM program. In general, these engines were rated under 50 bhp and were powered by produced gas from the individual sites. The engines were not observed to have any emission controls on their exhaust. As long as the supply of produced gas was available or as necessary, the engines were operated continuously 24 hours a day, 7 days a week. Because the observed engines were rated at less than 50 bhp, Rules 1110.2 and 1470 do not apply. Thus, the engines used to operate wellhead pumps generally do not have an emission limit unless the engine is rated greater than 50 bhp.

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, engines are not included in their respective regulations. However, in their suite of rules, other regulatory agencies do regulate emissions from stationary internal combustion engines such as: BAAQMD Regulation 9 – *Inorganic Gaseous Pollutants*, Rule 8 – *Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines* and SJVAPCD Rule 4702 – *Internal Combustion Engines.*

- *Assessment of Pollution Control Technologies*

<u>Application of Nonselective Catalytic Reduction Technology</u>

During site visits, staff noted that the internal combustion engines observed were engines that are classified as rich-burn engines. Rich-burn engines operate at a higher concentration of fuel to air in its combustion chamber compared to lean-burn engines which operate at a higher concentration of air to fuel in its combustion chamber. With a higher concentration of fuel to air, rich-burn engines respond to varying loads more effectively compared to lean-burn engines. On oil field and gas production sites, the supply of produced gas to an engine can vary making the rich-burn engine one of choice and necessity.

Although no exhaust emission controls were observed on engines used to operate wellhead pumps, there exists commercially available air pollution control equipment that can be installed on rich-burn engines such that if operated properly can achieve emission reduction compliant to the NOx emission limit established in Rule 1110.2.

Nonselective Catalytic Reduction (NSCR) technology is applicable to all rich-burn engines and is a common control method for rich-burn engines (See Figure 2.8). The first wide scale application of NSCR technology occurred in the mid- to late-1970s, when 3-way NSCR catalysts were applied to motor vehicles with gasoline engines. Since then, this control method has found widespread use on stationary engines. Improved NSCR catalysts, called 3-way catalysts because CO, VOC, and NOx are simultaneously controlled, have been commercially available for stationary engines for over 20 years.


Figure 2.8 – Example of an NSCR Device

The NSCR catalyst promotes the chemical reduction of NOx in the presence of CO and VOC to produce oxygen and nitrogen. The 3-way NSCR catalyst also contains materials that promote the oxidation of VOC and CO to form carbon dioxide and water vapor. To control NOx, CO, and VOC simultaneously, 3-way catalysts must operate in a narrow air/fuel ratio band (15.9 to 16.1 for natural gas-fired engines) that is close to stoichiometric.

Removal efficiencies for a 3-way catalyst are greater than 90 percent for NOx, greater than 80 percent for CO, and greater than 50 percent for VOC. Greater efficiencies, below 10 parts per million NOx, are possible through use of an improved catalyst containing a greater concentration of active catalyst materials, use of a larger catalyst to increase residence time, or through use of a more precise air/fuel ratio controller.

NSCR catalysts are subject to masking, thermal sintering, and chemical poisoning. In addition, NSCR is not effective in reducing NOx if the CO and VOC concentrations are too low. NSCR is also not effective in reducing NOx if significant concentrations of oxygen are present. In this latter case, the CO and VOC in the exhaust will preferentially react with oxygen instead of the NOx. For this reason, NSCR is an effective NOx control method only for rich-burn engines.

When applying NSCR to an engine, care must be taken to ensure that the sulfur content of the fuel gas is not excessive. The sulfur content of pipeline-quality natural gas and LPG is very low, but some oil field gases and waste gases can contain high concentrations. Sulfur tends to collect on the catalyst, which causes deactivation. This is generally not a permanent condition and can be reversed by introducing higher temperature exhaust into the catalyst or simply by heating the catalyst. Even if deactivation is not a problem, the water content of the fuel gas must be limited when significant amounts of sulfur are present to avoid deterioration and degradation of the catalyst from sulfuric acid vapor.

In cases where an engine operates at idle for extended periods or is cyclically operated, attaining and maintaining the proper temperature may be difficult. In such cases, the catalyst system can be designed to maintain the proper temperature, or the catalyst can use materials that achieve high efficiencies at lower temperatures. For some cyclically operated engines, these design changes may be as simple as thermally insulating the exhaust pipe and catalyst. Most of these limitations can be eliminated or minimized by proper design and maintenance.

Electrification of All Engines

During site visits, staff observed that most wellhead pumps are electrically driven. However, on a few sites, some wellhead pumps were being powered by engines fueled by produced gas. Staff noted that on these few sites, the produced gas could not be routed offsite for further processing or collection. In order to maintain operation of the site, the operator could either vent the produced gas to the atmosphere, install a combustion device to flare it, install a boiler or heater to consume it, or utilize an internal combustion engine or a stationary turbine to produce power to run a wellhead pump. In the past, another option included potentially reinjecting the produced gas back into the oil formation; however, staff has learned that other regulatory agencies such as the City of Los Angeles Zoning Administrator severely restrict this practice and it is no longer common.

(3) Establishing emission limits for stationary gas turbines using produced gas for fuel

- *Assessment of Current South Coast AQMD Regulatory Requirements*

During the rule development process, staff visited multiple sites where stationary gas turbines were operated using process gas as their fuel source. Currently, Rule 1148.1 does not have an emission limit for turbines operated at facilities subject to this rule. However, for turbines that are rated at 0.3 MW and larger, South Coast AQMD Rule 1134 – *Emissions of Oxides of Nitrogen from Stationary Gas Turbines* applies.

- *Assessment of Emission Limits of Existing Units*

Rule 1134 limits NOx emissions from stationary gas turbines that are fueled by produced gas to 9 ppmv at 15% O_2 on a dry basis. For engines rated at less than 0.3 MW, there is currently no emission limit set by the South Coast AQMD.

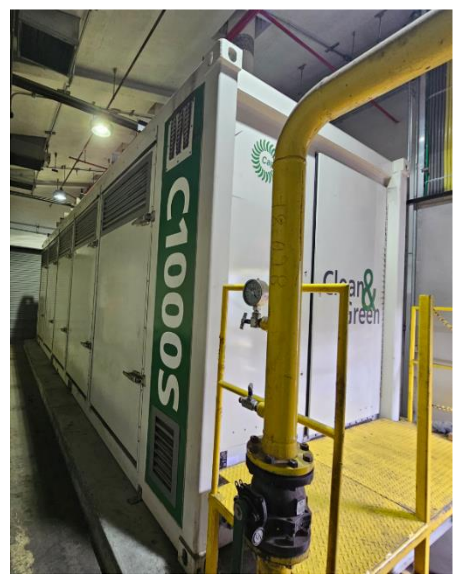


Figure 2.9 – Example of a Stationary Gas Turbine

- *Other Regulatory Requirements*

Staff reviewed rules and regulations from other air districts and agencies and noted that for rules that similarly regulate oil and gas production sites, stationary gas turbines are not included in their respective regulation. However, in their suite of rules, other regulatory agencies do regulate the emissions from stationary gas turbines engines such as: BAAQMD Regulation 9 – *Inorganic Gaseous Pollutants*, Rule 9 – *Nitrogen Oxides Stationary Gas Turbines* and SJVAPCD Rule 4703 – *Stationary Gas Turbines*. These rules also exempt smaller turbines such as those used at oil and gas well production sites.

The CARB Distributed Generation Certification Regulation is available to smaller gas turbines that are exempt from air district permitting requirements. These units must demonstrate that they meet or exceed the following emission standards:

Table 2.1: DG Emission Standards

Pollutant	Emission Standard (lb/MW-hr)
NOx	0.07
CO	0.10
VOCs	0.02

- *Assessment of Pollution Control Technologies*

To control NOx emissions, Selective Catalytic Reduction (SCR) technology is often used. SCR is a commercially available air pollution control system used to reduce NOx emissions from stationary gas turbines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Dry Low NOx controls NOx by combusting gas at lower temperatures using a lean premixed combustion. An advanced control system in also utilized. Low NOx levels are achieved as the process requires less fuel and air resulting in lower combustion temperatures.

(4) Requiring electrification or the use of cleaner engines for workover rigs

- *Assessment of Current South Coast AQMD Regulatory Requirements*

Currently, the electrification or the use of cleaner engines for workover rigs is not required Rule 1148.1. Other South Coast AQMD rules do not mandate the use of electrified or cleaner engines. However, Rule 1148.2 requires the operator of a workover rig where the engine does not meet a minimum Tier 4 – Final emissions standards of title 40 of the Code of Federal Regulations part 1039 subpart B section 1039.101 Table 1 and the engine is not powered by a non-combustion source to notify the Executive Officer no more than ten (10) calendar days and no less than 24 hours prior to the use of the workover rig on either an onshore oil or gas well, or an injection well. This engine standard shall also apply to any engine that connects to, and assists, the workover rig with any well activity.

- *Assessment of Emission Limits of Existing Units*

Typically, workover rigs use engines that are considered to be off-road compression-ignition diesel engines and are registered through CARB's PERP. Depending on the age and the rated bhp of the engine, an engine is assigned to a Tier category. Based on the tier level, emission limits vary. For example, a 2008 engine rated between 75 – 100 bhp falls under the Tier 3 category and it has a NOx emission limit of 3.5 g/bhp-hr (~ 234 ppmv at 15% O_2). In comparison, a 2015 engine rated similarly falls under the Tier 4 Final category and it has a NOx emission limit of 0.14 g/bhp-hr (~ 9 ppmv at 15% O_2). It should be noted that engines which are integrated with the propulsion of the rig itself is not included in CARB's PERP.

Figure 2.10 – A Workover Rig in Operation

- *Other Regulatory Requirements*

U.S. EPA has developed Tier 4 standards for nonroad diesel engines to reduce emissions. Exhaust emissions from Tier 4 engines decrease emissions from older engines by more than 90 percent[3]. The Tier 4 standards took effect for new engines beginning in 2008 and were fully phased in for most diesel engines by 2014. Thus, new engines manufactured after 2008 are required to meet the applicable standard effective when the engine is built. Staff has noted that engines used on workover rigs range between 175 ≤ hp < 750 and widely range in age. Staff has observed during site visits that only some engines used on workover rigs are currently required to meet Tier 4 standards.

The Tier 4 emission standards are provided in the table below.

[3] Reference: https://nepis.epa.gov/Exe/ZyPDF.cgi/P10003DS.PDF?Dockey=P10003DS.PDF U.S. EPA, Summary and Analysis of Comments: Control of Emissions from Nonroad Diesel Engines, May 2004

Table 2.2 – Final Emission Standards in grams per horsepower-hour (g/hp-hr)

Rated Power	First Year that Standards Apply	PM	NOx
hp < 25	2008	0.30	-
25 ≤ hp < 75	2013	0.02	3.5*
75 ≤ hp 175	2012-2013	0.01	0.30
175 ≤ hp < 750	2011-2013	0.01	0.30
hp ≥ 750	2011-2014 2015	0.075 0.02/0.03**	2.6/0.50† 050††

* The 3.5 g/hp-hr standard includes both NOx and nonmethane hydrocarbons
† The 0.05 g/hp-hr standard applies to gensets over 1200 hp
** The 0.02 g/hp-hr standard applies to gensets; the 0.03 g/hp-hr standard applies to other engines
†† Applies to all gensets only.

- *Assessment of Pollution Control Technologies*

SCR Technology

To achieve Tier 4 final NOx emission levels, engine manufacturers will use small-scaled SCR units on the exhaust of these engines. SCR technology injects ammonia into a turbine's exhaust. The exhaust is then passed through a fixed catalyst bed where NOx reacts with the ammonia and is converted into nitrogen. If CO and VOCs are also to be controlled, then an oxidation catalyst is added to the exhaust stream typically upstream of the SCR. Catalyst efficiency relies on good dispersion and mixing. Typical conversion efficiencies for SCR systems range between 90 – 95% for NOx.

Electrification of Engines Used for Workover Rigs

Staff observed the use of an electrified workover rig at two different sites and is aware of another electrified workover rig that had once been installed and operated at another site. At the two sites where there was an electrified rig, staff noted that the units were not capable of leaving the site and were confined to move on a fixed rail system within the facility. In addition, each site had been retrofitted with a robust electrical substation to meet the electrical demand required by a workover rig. The fixed rail system would also be especially challenging for oil and gas well sites that are difficult to access due to terrain and location. See Figure 2.11 for photos on an electrically powered drilling/workover rig.

Figure 2.11 – Photo on left shows electrified drilling/workover rig and photo on right shows inside view. Note that this drilling/workover rig is on a rail and can only be used at this specific site

CHAPTER 3: PROPOSED AMENDMENTS TO RULE 1148.1

INTRODUCTION

Staff participated in multiple meetings with WCWLB and SLA community residents, acknowledged the CERP, conducted multiple site visits to oil and gas production sites, conducted a BARCT assessment, and presented our findings in a public process. The following proposals address the concerns raised in these communities.

PROPOSED AMENDMENTS TO RULE 1148.1

Subdivision (c) – Definitions

The definitions listed below are being revised or added due to the proposed amendments to Rule 1148.1:

- **COMPONENT** – The definition is updated to include the wellhead and stuffing box as recognized components.

- **ENGINE** – During the rule development process, staff noted that produced gas was being utilized to power engines used to operate wellheads. Staff has added this definition as part of introducing emission limits onto engines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1110.2 for development of this definition.

- **FUEL CELL** – The definition is added to recognize the technology as an alternate to engines. U.S. EPA describes fuel cells as follows. A fuel cell is an electrochemical device similar to a battery. While both batteries and fuel cells generate power through an internal chemical reaction, a fuel cell differs from a battery in that it uses an external supply that continuously replenishes the reactants in the fuel cell. A battery, on the other hand, has a fixed internal supply of reactants. The fuel cell can supply power continuously as long as the reactants are replenished, while the battery can only generate limited power before it must be recharged or replaced.[4]

- **GAS HANDLING** – Staff discussed the intent of gas handling operations within the Applicability section of the rule and discovered a potential misunderstanding of using the term "processed gas" instead of "produced gas." Staff updated rule language to state "produced gas" in the first sentence of the Applicability section and created a definition for "gas handling" to further clarify the intent of this rule.

- **NEUTRALIZING AGENTS** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities had expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public. However, staff is making a distinction between neutralizing agents which differ from odorants that specifically are designed to mask an odor.

[4] Reference: U.S. EPA Auxiliary and Supplemental Power Fact Sheet: Fuel Cells, accessed at https://www.epa.gov/sites/default/files/2019-08/documents/fuel_cells_fact_sheet_p1004xfm.pdf

- **ODORANT** – Staff has added this definition as part the proposal to remove the use of odorants from oil and gas production sites. AB 617 communities have expressed concern that odorants may be masking chemicals that can be harmful to the environment and to members of the public.

- **OPTICAL GAS IMAGING DEVICE** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **STATIONARY GAS TURBINE** – During the rule development process, staff noted that produced gas was being utilized to power stationary gas turbines that produce electricity to either power the site or supply the local electrical power grid. Staff has added this definition as part of introducing emission limits onto turbines that are powered and consuming produced gas from oil field and production sites. Staff referenced South Coast AQMD Rule 1134 for development of this definition.

- **TIER 4 FINAL ENGINE** – U.S. EPA finalized Tier 4 standards for nonroad diesel engines that reduce emissions by integrating engine and fuel controls as a system. Exhaust emissions of PM and NOx from these engines will decrease by more than 90 percent. These standards are achieved through the use of advanced exhaust gas after-treatment technologies such as urea-selective catalyst reduction (SCR) catalysts for NOx control, and diesel particulate filters (DPFs) for PM control. The use of ultra-low sulfur diesel (ULSD) fuel with a maximum sulfur content of 15 ppm or less is also generally required.

- **VISIBLE VAPORS** – Staff has added this definition as part of introducing enhanced monitoring technology into the rule. Staff referenced South Coast AQMD Rule 1178 for development of this definition.

- **WORKOVER RIG** – Staff has added this definition to describe what a workover rig is. Staff developed this definition by researching various oil field industry websites that listed workover rigs, and from first-hand observations of workover rigs used in the local oil field production facilities.

Subdivision (d) – Requirements

The requirements listed below are being revised or added due to the proposed amendments to Rule 1148.1.

- Paragraphs (d)(7) and (d)(9) – The word "business" was removed from these paragraphs for consistency. The oil and gas production facilities operate 24 hours a day and 7 days a week. Therefore, there is no need to distinguish a business day from a regular day.

- Paragraph (d)(13) – During the amendment to Rule 1148.2 – *Notification and Reporting Requirements for Oil and Gas Wells and Chemical Suppliers*, concerns were raised about signs installed at oil field and production sites. AB 617 stakeholders requested that instructions be provided on how to make odor complaints and electronically access additional on well activities. Staff referenced South Coast AQMD Rule 1460 –*Control of Particulate Emissions from Metal Recycling and Shredding Operations* for development of this requirement. Figure 3.1 shows a typical sign for an oil and gas facility.

Figure 3.1 **-** Example of Signage Prior to Amendment

- Paragraph (d)(14) – Staff has added this requirement as part of introducing enhanced monitoring technology using an OGI camera as part of the inspection process.

- Paragraph (d)(15) – Staff has added a NOx emission limit to engines that are powered by produced gas. During site visits, staff discovered engines being used to process produced gas from oil field sites. These engines were observed in the operation of wellheads and similar production equipment.

  Generally, produced gas can be collected and routed from an oil field to another location offsite to be further processed into a usable stream. For example, some produced gas can be sent to supply the Southern California Gas Company or similar company. Alternatively, produced gas can be collected from an oil field and used onsite to power combustion equipment such as a stationary gas turbine, an engine. If the gas cannot be sent offsite or used to power combustion equipment, then it is vented to a flare.

  In the case of engines using produced gas, staff discovered that these engines were typically rated at less than 50 bhp. By using engines that are rated less than 50 bhp, an engine is not subject to the emission limits established in Rule 1110.2. Rule 1110.2 applies only to engines rated greater than 50 bhp. In addition, the South Coast AQMD does not require a permit to operate for an engine rated less than 50 bhp unless the engine is located at a facility subject to the South Coast AQMD RECLAIM program. Whether an engine is specifically designed to avoid regulation under Rule 1110.2 or permitting requirements or if this circumstance is more a reflection of the low volume of produced gas supply needed for a larger engine to run is not determined. Rule 1110.2 may be amended in future rulemaking activity to include engines that are rated at less than 50 bhp. However, since these engines currently are operated at oil and gas production facilities, staff has included them under this rule to address air quality concerns and potential health impacts to the community.

Staff is concerned that this type of engine is an uncontrolled source of emissions. Staff visited sites where these engines were observed in operation and noted that these engines can operate continuously 24 hours a day, 7 days a week based on produced gas supply and/or electrical demand. Upon observing these engines, staff did not see any emission control devices on them. Staff also has observed that multiple engines can operate within proximity to each other where although a single engine may be rated at less than 50 bhp, the aggregate horsepower of all of the engines on the site exceeds 50 bhp. In addition, staff has observed that some of these engines are located within less than 1000 feet of sensitive receptors such as residences and other dwellings.

During the third working group meeting that was held on December 14, 2023, staff received a comment inquiring if the produced gas could be reinjected back into the ground. Staff researched the inquiry and held a meeting with an LA City Planning employee and discovered that reinjecting gas back into the ground is discouraged due to safety concerns of having gas stored below residential neighborhoods. Additionally, LA City prefers to have the produced gas used in microturbines that meet certain emission standards. Staff also recognizes that CalGEM already regulates injection wells, including underground gas storage.

To address concerns over these engines, staff is proposing that engines meet the NOx emission limit applicable to engines regulated by Rule 1110.2 irrespective of rating. Currently, the NOx emission limit for Rule 1110.2 engines is established at 11 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(16) – Staff has added a NOx emission limit to stationary turbines that are powered by produced gas. During site visits, staff observed stationary turbines being used to process produced gas from oil field sites generating electricity that was either being used onsite or was exported to the electrical power grid. For stationary turbines rated greater than 0.3 MW, Rule 1134 applies; however, for units rated less than 0.3 MW, no emission limits are applicable. Staff has generally observed microturbines that are rated at 65 kW (0.065 MW) at various oil and gas production sites with some larger ones rated at 200 kW (0.2 MW).

  To address concerns over turbines that are not subject to Rule 1134, staff is proposing that all stationary turbines meet the NOx emission limit applicable to stationary turbines as regulated by Rule 1134 irrespective of rating. Staff considers that the amount of microturbines installed and operated at oil and gas production sites to be a small number. Thus, rather than amend Rule 1134, staff is including this subset of turbines in this rule. Currently, the NOx emission limit for Rule 1134 turbines fueled by produced gas engines is established at 9 ppmv at 15% O2, on a dry basis with limited exceptions. To phase in compliance with this proposal, staff proposes a two-year implementation period from the date of the rule amendment to be reasonable amount of time for operators of such equipment to either retrofit existing equipment, install new equipment, or find alternative solutions.

- Paragraph (d)(17) – Staff is proposing that workover rigs used at oil and gas well sites be equipped with at least a Tier 4 Final engine. Based on AB 617 community concerns over emissions from diesel workover rigs, staff conducted site visits and also researched the potential emission reductions and feasibility of requiring electrified workover rigs. Part of the research included conducting a cost-effectiveness analysis. The results indicated that electrifying the workover rigs would exceed the cost-effectiveness threshold and take many more years to implement due to lack of infrastructure that would be needed.

  To address concerns over emissions from workover rigs, staff is proposing requiring all workover rigs to meet Tier 4 Final standards. While conducting research on this proposal staff found that the emission reductions on a Tier 4 Final engine are significant compared to Tier 2 level engines and this requirement was found to be cost-effective. Staff is proposing a three-year implementation period from the date of this rule amendment to either upgrade or replace their fleet of workover rigs. In addition, staff has found that some oil and gas operators have already upgraded part of their workover fleet to meet Tier 4 Final engine standards.

- Paragraph (d)(18) – Staff is proposing to ban the use of odorants, specifically odorants that are used to mask another chemical substance's smell. AB 617 community stakeholders have expressed concerns about the use of odorants and the potential exposure to unknown chemicals.

  Staff researched and found that some oil and gas production site operators are using odorants with strong fruit fragrances like guava or cherry. These operators have attempted to mask petroleum and oily-type odors with these odorants but it has led to several public nuisance violations with complaints of rotten fruit-type odors mixed with petroleum odors. Some complainants described having headaches. Mistrust has been created among community members due to the lack of knowledge about an odorant's chemicals and the substance that is being masked with the odorant. Odorants are generally composed of hydrocarbons such as alcohols and glycols but may also contain phenols or aromatics. These chemicals contribute to ozone formation and public nuisance complaints. They may also have health impacts depending on the type and quantity of the odorant substance.

  Staff recognizes that oil and gas operators may use neutralizing agents as an alternative to odorants on maintenance of their wells, including during the removal of well tubing as the well tubing may have its own odors. Neutralizing agents work to "knock out" or eliminate the odors, as opposed to masking the odors. Staff has proposed to allow the continued use of neutralizing agents that do not contain any toxics listed in Rule 1401 in quantities greater than 0.1 percent by weight. Staff also suggests that neutralizing agents be applied in liquid or droplet form and should not be aerosolized. If a neutralizing agent were aerosolized, these chemicals may create odors. Staff has added definitions to clarify the differences in this requirement by adding the word 'odorant' and the word 'neutralizing agent' to the list of definitions.

It should be noted that this requirement does not affect the use of mercaptans or other chemicals that are purposefully injected into specific gas lines for safety purposes such as for detecting a gas leak in gas lines that are used, for example, in sales.

Subdivision (e) – Operator Inspection Requirements

- Paragraph (e)(6) – Staff has added an enhanced leak detection requirement using an OGI camera. The requirement has been modeled after the OGI requirement found in SJVAPCD Rule 4409. Comparing the use of an OGI camera with the use of a TVA, staff recognizes differences between the two applications. The OGI camera is expected to be used as a screening tool. With its current technological capabilities, an OGI camera cannot quantify an emission concentration whereas a TVA can report an emission in a concentration value. However, an OGI camera can be used to scan more components more quickly compared to a TVA which relies on inspecting one component at a time. Used together, the congruence of this technology is expected to give an operator the ability to identify leaks more quickly and to repair them sooner compared with not using both in unison. If a visible vapor is observed while inspecting with an OGI camera, the operator will be required to quantify in parts per million by volume (ppmv), any VOC emissions within 48 hours of when visible vapors are detected. Quantification must be done using an appropriate analyzer that complies with paragraph (j)(1). In addition, should a visible vapor be quantified where the emission level triggers a repair, replacement, or removal of a component in accordance with the requirements of South Coast AQMD Rule 1173, then a notification to South Coast AQMD will also be required to be made within 24 hours of such quantification.

  Components and other equipment subject to this rule will be required to be inspected once per calendar month. Once a leak has been identified, the operator will be required to repair the leak per the repair schedule referred to in South Coast AQMD Rule 1173.

Subdivision (i) – Testing Requirements

New subdivision (i) was added to demonstrate compliance with emission limits proposed in the amendment to the rule.

- Paragraph (i)(1) – Staff added a source testing requirement for engines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Prior to this amendment, many engines that fell under this category were rated under 50 bhp and no testing requirement was in place. Although these engines may be considered small, they can operate 24 hours a day, 7 days a week and cumulatively, the amount of emissions can be significant.

- Paragraph (i)(2) – Staff added a source testing requirement for stationary turbines that use produced gas as a fuel source in order to demonstrate compliance with its emission limit. Although this provision is identical to the provision in paragraph (i)(1), it is included to distinguish turbines from engines. Specifically, an exemption from source testing is provided in paragraph (k)(5) if the turbine is certified through CARB's Distributed Generation program. No similar program is available for engines using produced gas.

Subdivision (j) – Test Methods

- Paragraph (j)(6) – Since emission limits for equipment have been included in this amendment, staff is adding that any source testing be completed per South Coast AQMD Method 100.1.

Subdivision (k) – Exemptions

- Paragraph (k)(5) – Staff added an exemption for a stationary turbine that has been certified by CARB Distributed Generation Certification program such that no source test of the engine shall be required. For engines that have not been certified as such, they will be required to demonstrate compliance via a periodic source test.

Other Revisions

- Since the 2015 Amendment to the rule, the California Department of Conservation, Division of Oil, Gas and Geothermal Resources (DOGGR) has been replaced by the California Geologic Energy Management (GEM) Division. Reference to DOGGR has been replaced with GEM.

- The name of the agency such as AQMD or District has been replaced by the South Coast AQMD.

- Staff updated references within the rule to account for amendments and deleted obsolete wording and provisions.

- Staff considered revisions to paragraph (d)(8) but believes that the current language allows flexibility to address leaks from equipment associated with well heads and well cellars. For example, produced gas from a tank that has been blocked-in but contains inventory from oil and gas field production activities shall be routed to a system handling gas for fuel, sale, or underground injection or to a control device so as to avoid leaks.

CHAPTER 4: IMPACT ASSESSMENTS

INTRODUCTION

Impact assessments were conducted as part of PAR 1148.1 rule development to assess the environmental and socioeconomic implications of PAR 1148.1. These impact assessments include emission reduction calculations, cost-effectiveness and incremental cost-effectiveness analyses, a socioeconomic assessment, and a California Environmental Quality Act (CEQA) analysis. Staff prepared draft findings and a comparative analysis pursuant to Health and Safety Code Sections 40727 and 40727.2, respectively.

EMISSION REDUCTIONS

PAR 1148.1 will establish more stringent control and monitoring requirements at oil and gas production sites that will result in emission reductions.

OGI Monitoring

Staff is proposing the monthly use of OGI as a tool to find leaks from equipment regulated by this rule. By using OGI, leaks can be discovered sooner than through current inspection frequency and technique. Emission reductions from this proposal were calculated based on estimated baseline emissions and assumed one major leak per year from ten percent of the 330 affected facilities. Staff used a leak rate of 200 lbs/day of VOC for each assumed major leak rate. This assumed leak rate is 98% smaller than the leak rate used in Rule 1178 but is expected to be consistent with the type of facilities regulated by this rule. Rule 1178 estimated approximately 8,000 lbs/day of emission losses based on U.S. EPA's 2016 Control Technology Guidelines for Oil and Gas Industry.[5]

Currently at a quarterly inspection frequency, staff assumes that an undiscovered leak happens at a midpoint between inspections of 45 days. If the inspection frequency is increased to monthly, then staff assumes that an undiscovered leak happens at a midpoint of 15 days. Comparing the current quarterly inspection frequency using the existing inspection equipment which consist of a TVA to the proposed monthly frequency using OGI equipment, staff predicts that a potential leak may be discovered approximately 30 days sooner, a difference between 45 and 15 days.

To establish a baseline rate of potential emission, staff performed the following calculation:

- One leak per year from ten percent of 330 affected facilities
- A leak rate of 200 lb/day of VOC
- 45 days before a leak is identified

[5] Reference: https://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1178/par-1178-draft-staff-report--final.pdf?sfvrsn=10, page 4-2

- Calculation – (1 leak/yr) x (33 facilities) x (200 lb VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lb) = 0.41 tons VOC/day
- Using these assumptions, a baseline of 0.41 potential tons per day of VOC is attributable to Rule 1148.1 related equipment.

With OGI monthly inspections, staff anticipates a reduction in VOC emissions compared to the baseline. To determine the reduction, staff performed the following calculation:

- One leak per year from ten percent of 330 affected facilities
- A leak rate of 200 lb/day of VOC
- Discovery of a leak 30 days sooner
- Calculation – (1 leak/yr) x (33 facilities) x (200 lb VOC/day) x (30 days) x (1 yr/365 day) x (1 ton/2000 lb) = 0.27 tons VOC/day
- Using these assumptions, a reduction of 0.27 potential tons per day of VOC is attributable to OGI monthly inspections.

Fenceline Monitoring

Stationary Gas Sensors

Staff researched different types of fenceline monitoring systems and found that several oil and gas facilities had stationary gas sensors installed, primarily as a trial run for data collection. Staff found that that stationary gas sensors detect the targeted gas/emission such as VOCs once it makes contact with its sensor. During the research of fenceline monitors staff found that the number of sensors needed at each site varied depending on the size and terrain.

To determine potential emission reductions through fenceline monitoring using stationary gas sensors, staff used a similar approach to that used for OGI monitoring. In this case, since stationary monitors operate continuously, the emission reduction is credited as saving 45 days of undiscovered emissions. To quantify the reduction, staff performed the following calculation:

- One leak per year from ten percent of 330 affected facilities
- A leak rate of 200 lb/day of VOC
- 45 days of a leak that was identified
- Calculation – (1 leak/yr) x (33 facilities) x (200 lb VOC/day) x (45 days) x (1 yr/365 day) x (1 ton/2000 lb) = 0.4 tons VOC/day
- Using these assumptions, a reduction of 0.4 potential tons per day of VOC is attributable to stationary gas sensors.

Open Path Sensors

As an alternative to stationary gas sensors staff researched open path sensors and found that they use a transmitter to transmit a beam to a reflector that sends the beam back. Detection of a targeted gas/emission such as VOCs is made when it makes contact with the beam. Staff did not find any oil and gas production sites using open path sensors but included this as an option. Since open path sensors operate continuously like stationary gas sensors, a reduction equivalent of 0.4 potential tons per day of VOC would be expected. See calculation performed in the previous section for additional details.

Engines Powered by Produced Gas

Staff is proposing requiring facilities that use their produced gas to power engines that drive oil producing wells to meet a NOx emission standard of 11 ppmv @ 15% O_2 on a dry basis. This emission limit was obtained from South Coast AQMD Rule 1110.2 Table 2 for stationary engines. Emission reductions from this proposal were calculated based on the assumption that an unregulated engine used in this service has equivalent emissions of a spark ignition engine.[6] The reason that staff assumed a spark ignition engine is that these engines were powered by produced gas versus diesel as with typical compression ignition engines. With the proposed exhaust emission controls using a 3-way catalyst with an air-to-fuel ratio control, staff expects a reduction in NOx emissions of approximately 90%.

To determine potential reductions in NOx emissions through the installation of exhaust emission controls, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engine rated at 50 bhp
- Engine operates continuously: 24 hours, 365 days
- 90% reduction efficiency for catalyst system
- Calculation – (90% reduction) x (1.5 g/hp-hr) x (50 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lb) x (1 yr/365 days) = 0.0018 tons NOx/day
- Using these assumptions, a reduction of 0.0018 potential tons per day of NOx is attributable to the installation of exhaust emission controls

It should be noted that this calculation is on a per engine basis and the total emissions reduced will vary by the actual number of engines retrofitted and used at oil and gas production sites.

Microturbines Powered by Produced Gas

As an alternative to routing produced gas to engines, staff acknowledges that stationary gas turbines can also use produced gas resulting in a similar NOx emission reduction of approximately 90%. Staff is proposing that the NOx emission limit for microturbines be 9 ppmv @ 15% O_2 on a dry basis, which was obtained from Table 1 from Rule 1134 for stationary gas turbines. Emission

[6] Reference: https://ww2.arb.ca.gov/sites/default/files/2020-03/PERP_Reg_12.5.18R.pdf, page 21

reductions from this proposal were calculated based on the assumption that one microturbine would replace three unregulated engines with equivalent emissions of spark ignition engines as referenced above in the "Engines Powered by Produced Gas" section. Staff selected this ratio as representative of the amount of gas needed to sustain operation of a small microturbine relative to the amount of gas needed to sustain operation of an engine.

To determine potential reductions in NOx emissions through the installation of a microturbine replacing engines operating on produced gas, staff performed the following calculation:

- Uncontrolled emission factor for spark ignition engine of 1.5 g/hp-hr NOx (CARB reference emission data)
- Engines rated at 50 bhp (3 engines = 150 hp capacity)
- Engine operates continuously: 24 hours, 365 days
- Emission factor for a microturbine of 0.16 g/hp-hr (from manufacturer datasheet)
- Calculation – (1.5 g/hp-hr – 0.16 g/hp-hr) x (150 hp) x (365 days/yr) x (24 hr /day) x (1 lb/453 g) x (1 ton/2000 lb) x (1 yr/365 days) = 0.005 tons NOx/day
- Using these assumptions, a reduction of 0.005 potential tons per day of NOx is attributable to the installation of one microturbine in lieu of three engines

It should be noted that this calculation is on a per microturbine basis and the total emissions reduced will vary by the actual number of microturbines installed and used at oil and gas production sites.

Use of Tier 4 Final Workover Rigs

Staff is proposing that workover rigs be powered by engines that are at least rated as Tier 4 Final. By requiring the use of Tier 4 Final engines on workover rigs, staff expects a significant reduction in emissions whenever the use of workover rigs is required. Staff assumed that the emissions from current workover rigs to be at Tier 2 levels. Staff also assumed that a workover rig is required four times per year at each site, is used four days per week, and eight hours per day. Workover rig engine size will vary. Staff assumed a rating of 600 hp to be representative of a typical engine. As noted previously, staff identified that there are approximately three hundred and thirty sites. To service these sites, staff estimated that approximately 40 rigs may be needed to cover potential demand.

To determine potential reductions in NOx emissions through the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig, staff performed the following calculation:

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Tier 4 Final NOx emission factor of 0.30 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day

- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr – 0.30 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lb) x (1 yr/365 days) = 0.51 tons NOx/day
- Using these assumptions, a reduction of 0.51 potential tons per day of NOx is attributable to the requirement of using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig

Electrification of Workover Rigs

Staff researched the feasibility of requiring oil and gas production facilities to use electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule development process, staff visited multiple oil and gas production sites and spoke to industry representatives and vendors. From these discussions and interaction, staff was made aware that the use of an electrically powered drilling/workover rig was only available at two sites. Staff visited these sites and found that these two sites were unique in that each had dedicated infrastructure installed to meet the electrical demands of these electrified drilling/workover rigs. Staff noted that these electrified drilling/workover rigs were designed to only operate at their respective sites and were not mobile.

To determine potential reductions in NOx emissions through the use of an electrified rig, staff performed a calculation similar to one comparing using Tier 4 Final rated engines relative to Tier 2 engines on a workover rig. In this case, however, an electrified rig is assumed to emit zero NOx emissions.

- Tier 2 NOx emission factor of 4.5 g/bhp-hr
- Approximately 40 rigs may be needed
- Operation of a rig is 4 days per week, 8 hours per day
- Typical engine size is 600 bhp
- Calculation – (4.5 g/hp-hr) x (40 rigs) x (600 hp) x (8 hrs/day) x (4 days/week) x (52 weeks/yr) x (1 lb/453 g) x (1 ton/2000 lb) x (1 yr/365 days) = 0.54 tons NOx/day
- Using these assumptions, a reduction of 0.54 potential tons per day of NOx is attributable to the requirement of using an electrified rig versus a rig equipped with Tier 2 engines

Elimination of Odorants

Due to concerns raised by stakeholders, staff proposes to eliminate the use of odorants. Although some odorants may contain VOC material, the overall reduction in VOC emissions associated with this activity is not expected to be significant.

Improved Signage

By producing and installing new signs at oil and gas production sites, some additional emission may be generated, but these are expected to be one-time occurrences and are not expected to be significant.

COST-EFFECTIVENESS

Health and Safety Code Section 40920.6 requires a cost-effectiveness analysis when establishing BARCT requirements. The cost-effectiveness of a control is measured in terms of the control cost in dollars per ton of air pollutant reduced. The costs for the control technology include purchasing, installation, operation, maintenance, and permitting. Emission reductions were calculated for each requirement and based on estimated baseline emissions. The 2022 AQMP established a cost-effectiveness threshold of $36,000 per ton of VOC reduced. A cost-effectiveness that is greater than the threshold of $36,000 per ton of VOC reduced requires additional analysis and a hearing before the Governing Board on costs. The 2022 AQMD also established a cost-effectiveness threshold of $325,000 per ton of NOx reduced. A cost-effectiveness that is greater than the threshold of $325,000 per ton of NOx reduced would also require additional analysis and a hearing before the Governing Board on costs.

The cost-effectiveness is estimated based on the present value of the retrofit cost, which was calculated according to the capital cost (initial one-time equipment and installation costs) plus the annual operating cost (recurring expenses over the useful life of the control equipment multiplied by a present worth factor).

Cost-Effectiveness (CE) = Present Worth Value (PWV) / Emission Reduction (ER)

PWV = Total Install Cost (TIC) + Present Worth Factor (PWF) x Annual Cost (AC)

Capital costs are one-time costs that cover the components required to assemble a project. Annual costs are any recurring costs required to operate equipment. Costs were obtained for OGI monitoring, retrofitting an existing engine powered by produced gas to drive a well, microturbines powered by produced gas, Tier 4 Final equipped workover rigs, and electrification of workover rigs.

OGI Monitoring

Staff is proposing the monthly use of OGI equipment as a tool to find leaks from equipment regulated by this rule. Costs for this proposal were obtained from vendors and facilities. Some oil and gas companies already use an OGI camera and staff was able to obtain further cost information such as maintenance and labor. In addition, South Coast AQMD retains OGI cameras, and training and maintenance cost information was available.

The following information was used to calculate the cost-effectiveness of purchasing and using an OGI camera:

- Number of oil and gas companies to be at approximately 80
- Cost of an OGI camera = $120,000 with a 10-year life span
- Annual maintenance = $1000
- Training = $1,000 every two years ($500 per year)
- In-House labor 1 person working 8 hours/day at $50/hr = $400/day
- Monthly inspections = 12/year
- Emission reduction based on analysis conducted previously = 0.27 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $120,000 x 80 cameras = $9,600,000
- AC = $1000 [maintenance] + $500 [training] + (1 person x 8 hr/day x $50/hr x 12 inspections/yr) [labor] = $6300 per OGI camera or $504,000 for 80 cameras
- PWV = $9,600,000 + 8.111 x $540,000 = $13,688,000
- ER = (0.27 tpd VOC) x (365 day/yr) x (10 years) = 990 tons VOC
- CE = $13,688,000 / 990 tons VOC reduced = $13,800/ton VOC reduced

Based on these assumptions, the cost-effectiveness for requiring monthly inspections using OGI cameras is calculated to be $13,800/ton VOC reduced.

Fenceline Monitoring

Stationary Gas Sensors

As an alternative to OGI cameras, staff researched the use of stationary gas sensors for the monitoring of VOCs. Costs used in this analysis were obtained from oil and gas facilities that have already installed stationary gas sensors.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites is approximately 330
- Cost of each sensor = $3,115
- Number of sensors at a site = 14
- Installation cost of $30,000

- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.41 tpd VOC

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = (14 sensors x $3,115 + $30,000), all multiplied by 330 sites = $24,291,300
- AC = $10,000 x 330 sites = $33,000,000
- PWV = $24,291,300 + 8.111 x $33,000,000 = $51,057,600
- ER = (0.41 tpd VOC) x (365 day/yr) x (10 years) = 1,496 tons VOC
- CE = $51,057,600 / 1,496 tons VOC reduced = $34,100/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of stationary gas sensors is calculated to be $34,100/ton VOC reduced.

Staff considered both stationary gas sensors and the use of OGI cameras and calculated the incremental cost-effectiveness for both options. This analysis is included in the section “Incremental Cost-Effectiveness”.

<u>Open Path Sensors</u>

Open path sensors are an alternative to stationary gas sensors and work in a different way by having a beam projected from a transmitter to a reflector. Staff did not find an oil and gas site using this type of technology; however, staff is aware that it is being used at oil refineries. The staff report from South Coast AQMD Rule 1178 included cost-effective data which was used for this staff report.

The following information was used to calculate the cost-effectiveness of purchasing and installing fenceline monitoring equipment:

- Number of oil and gas sites to be at approximately 330
- Cost of each sensor = $190,000
- Installation cost per sensor = $190,000
- Number of sensors at a site = 4
- Estimated life span of 20 years
- Annual maintenance = $5,000
- Emission reduction based on analysis conducted previously = 0.41 tpd VOC

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = (4 sensors x $380,000), all multiplied by 330 sites = $501,600,000
- AC = $5,000 x 330 sites = $1,650,000

- PWV = \$501,600,000 + 13.59 x \$1,650,000 = \$503,250,000
- ER = (0.41 tpd VOC) x (365 day/yr) x (20 years) = 2,992 tons VOC
- CE = \$503,250,000 / 2,992 tons VOC reduced = \$168,200/ton VOC reduced

Based on these assumptions, the cost-effectiveness for the use of open path sensors is calculated to be \$168,200/ton VOC reduced.

It should be noted that this type of enhanced leak detection technology exceeds the cost-effective VOC threshold.

Engines Powered by Produced Gas

Staff is proposing that engines that are powered by produced gas and are used to drive an oil producing meet a NOx standard of 11 ppmv @ 15% O_2 on a dry basis. Staff researched technologies that could be used to meet this standard and also the option to replace these engines with microturbines which is discussed in the next section. Staff obtained cost information for the technology upgrades from vendors that supply and service engines to oil and gas facilities. Staff also used cost information for exhaust emission controls that was collected for the November 2019 amendment to Rule 1110.2.

The following information was used to calculate the cost-effectiveness of upgrading engines powered by produced gas used to drive an oil producing well:

- Cost of 3-way catalyst = \$5,000
- Cost of air/fuel ratio controller = \$1,000
- Cost of installation of parts = \$5,000
- Estimated life span of 3 years for parts operating 24 hrs/day
- Annual maintenance = \$1,000
- Emission reduction based on analysis conducted previously = 0.0018 tpd NOx

- PWF = 2.78 for a 3-year life expectancy at 4% interest rate
- TIC = \$11,000
- AC = \$1,000
- PWV = \$11,000 + 2.78 x \$1,000 = \$13,775
- ER = (0.0018 tpd NOx) x (365 day/yr) x (3 years) = 1.971 tons NOx
- CE = \$13,775 / 1.971 tons NOx reduced = \$7,000/ton NOx reduced

Based on these assumptions, the cost-effectiveness for upgrading engines powered by produced gas used to drive an oil producing well is calculated to be \$7,000/ton NOx reduced.

Microturbines Powered by Produced Gas

As an alternative to requiring emissions controls on engines, staff is proposing that microturbines replace engines that use produced gas. The NOx emission standard for microturbines is 9 ppmv @ 15% O_2 on a dry basis. It is assumed that one microturbine would replace three engines that are each being used to drive three wells. Staff obtained cost information on microturbines from a local vendor that offers them for sale with South Coast AQMD's jurisdiction.

The following information was used to calculate the cost-effectiveness of purchasing a microturbine rated at 65 kilowatts (kW):

- Cost of microturbine = $150,000
- Microturbine installation cost = $300,000
- Cost of electric motor = $5,000 (x 3 for 3 electric motors) needed to drive wells
- Installation of electric motors = $5,000 (x3 for 3 electric motors) needed to drive wells
- Estimated life span of 10 years
- Annual maintenance = $10,000
- Emission reduction based on analysis conducted previously = 0.005 tpd NOx

- PWF = 8.111 for a 10-year life expectancy at 4% interest rate
- TIC = $480,000
- AC = $10,000
- PWV = $480,000 + 8.111 x $10,000 = $561,110
- ER = (0.005 tpd NOx) x (365 day/yr) x (10 years) = 18.25 tons NOx
- CE = $561,110 / 18.25 tons NOx reduced = $30,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for installing a microturbine powered by produced gas used to drive an oil producing well is calculated to be $30,700/ton NOx reduced.

Use of Tier 4 Final Workover Rigs

Staff is proposing that engines on workover rigs be at least rated as Tier 4 Final. Staff obtained cost data from several operators that have either upgraded or replaced their workover rigs to be equipped with Tier 4 Final engines.

The following information was used to calculate the cost-effectiveness of purchasing a Tier 4 Final engine equipped workover rig:

- Cost of Tier 4 Final engine equipped workover rig = $1,000,000
- Estimated life span of 20 years
- Estimated number of Tier 4 Final engine equipped workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40

- Annual maintenance = $20,000
- Emission reduction based on analysis conducted previously = 0.51 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $1,000,000 = $40,000,000
- AC = 40 rigs x $20,000 = $80,000
- PWV = $40,000,000 + 13.59 x $800,000 = $50,872,000
- ER = (0.51 tpd NOx) x (365 day/yr) x (20 years) = 3,723 tons NOx
- CE = $50,872,000 / 3,723 tons NOx reduced = $13,700/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with engines that are at least rated as Tier 4 Final is calculated to be $13,700/ton NOx reduced.

Electrification of Workover Rigs

Staff researched the feasibility of oil and gas production facilities using electrified workover rigs instead of workover rigs equipped with diesel engines. During the rule making process staff received cost information from the only two operators that currently have an electrified workover rig on their respective sites. No other facility was found to have an existing electrified rig. Staff found that a substation would need to be installed at *each* site in order to meet the electrical demands that an electrified workover rig would require.

The following information was used to calculate the cost-effectiveness of requiring an electrified workover rig:

- Number of oil and gas sites to be at approximately 330
- Cost of electrified workover rig = $10,000,000
- Cost of substation per site = $5,000,000
- Estimated life span of 20 years
- Estimated number of electrified workover rigs needed to meet demand throughout South Coast AQMD's jurisdiction = 40
- Annual Maintenance for the rigs = $20,000
- Annual Maintenance for the substations = $10,000
- Emission reduction based on analysis conducted previously = 0.54 tpd NOx

- PWF = 13.59 for a 20-year life expectancy at 4% interest rate
- TIC = 40 rigs x $10,000,000 + 330 substations x $5,000,000 = $2,050,000,000
- AC = 40 rigs x $20,000 + 330 substations x $10,000 = $4,100,000
- PWV = $2,050,000,000 + 13.59 x $4,100,000 = $2,054,100,000
- ER = (0.54 tpd NOx) x (365 day/yr) x (20 years) = 3,942 tons NOx

- CE = $2,054,100,000/ 3,942 tons NOx reduced = $521,080/ton NOx reduced

Based on these assumptions, the cost-effectiveness for replacing older model workover rigs with an electrified rig (and the installation of the requisite infrastructure) is calculated to be $521,080/ton NOx reduced.

It should be noted that the electrification of workover rigs exceeds the cost-effective NOx threshold.

Elimination of Odorants

The elimination of odorants is not expected to produce any significant reductions in VOC emissions. Moreover, the elimination of odorants does not result in any new cost incurred by operators, but rather it is a cost that is no longer spent. Therefore, no cost-effective analysis was conducted for this proposal.

Improved Signage

By producing and installing new signs at oil and gas production sites, some additional emission reductions may be generated, but these are expected to be one-time occurrences and are not expected to be significant. Staff acknowledges that there will be one-time costs associated with this proposal, but does not consider these costs to be significant. Therefore, no cost-effective analysis was conducted for this proposal.

INCREMENTAL COST-EFFECTIVENESS

California Health and Safety Code section 40920.6 requires an incremental cost-effectiveness analysis for BARCT rules or emission reduction strategies when there is more than one control option which would achieve the emission reduction objective of the proposed amendments, relative to ozone, CO, SOx, NOx, and their precursors.

Options for Enhanced Monitoring

Staff conducted an incremental cost-effectiveness for OGI camera usage and stationary gas sensor monitoring as they both use enhanced technology for the detection of fugitive VOC emissions. Staff used the following formula to calculate incremental cost-effectiveness where option 1 is OGI monitoring and option 2 is stationary gas monitoring:

$$\text{Incremental Cost-Effectiveness} = \frac{\text{Cost of Option 2} - \text{Cost of Option 1}}{\text{Benefit of Option 2} - \text{Benefit of Option 1}}$$

$$\text{Incremental Cost-Effectiveness} = \frac{\$51{,}057{,}600 - \$13{,}688{,}000}{1{,}496 \text{ tons} - 990 \text{ tons}}$$

The incremental cost-effectiveness of using stationary gas sensors compared to OGI technology is calculated to be $73,900/ton VOC reduced.

Staff found that it was not cost-effective to use stationary gas sensors relative to OGI technology and therefore recommends the use of OGI technology as it is a more active and robust use of enhanced leak detection technology.

Options for Tier 4 Final Engine versus Electrification

Staff conducted an incremental cost-effectiveness for Tier 4 Final workover rigs versus electrified workover rigs where option 1 is the use of Tier 4 Final workover rigs and option 2 is the use of electrified workover rigs:

$$\text{Incremental Cost-Effectiveness} = \frac{\$2{,}050{,}000{,}000 - \$50{,}872{,}000}{3{,}942 \text{ tons} - 3{,}723 \text{ tons}}$$

The incremental cost-effectiveness of using electrified workover rigs compared to Tier 4 Final workover rigs is calculated to be $9,100,000/ton VOC reduced.

Staff found that it was not cost-effective to use electrified workover rigs relative to Tier 4 Final workover rigs.

SOCIOECONOMIC IMPACT ASSESSMENT

California Health and Safety Code section 40440.8 requires a socioeconomic impact assessment for proposed and amended rules resulting in significant impacts to air quality or emission limitations. A socioeconomic impact assessment will be conducted and released for public review and comment at least 30 days prior to the South Coast AQMD Governing Board Hearing.

CALIFORNIA ENVIRONMENTAL QUALITY ACT ANALYSIS

Pursuant to the California Environmental Quality Act (CEQA) and South Coast AQMD's certified regulatory program (Public Resources Code Section 21080.5, CEQA Guidelines Section 15251(l), and South Coast AQMD Rule 110), the South Coast AQMD, as lead agency for the proposed project, will be reviewing PAR 1148.1 to determine if any potential adverse environmental impacts will occur. Appropriate CEQA documentation will be prepared based on the analysis.

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Requirements to Make Findings

California Health and Safety Code section 40727 requires that the Board make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report. In order to determine compliance with sections 40727 and 40727.2, a written analysis is required comparing the proposed rule with existing regulations.

Necessity

A need exists to amend PAR 1148.1 to implement best available retrofit control technology and emission reduction strategies recommended in the WCWLB and SLA CERPs as part of the AB 617 commitment.

Authority

The South Coast AQMD obtains its authority to adopt, amend, or repeal rules and regulations pursuant to California Health and Safety Code sections 39002, 40000, 40001, 40440, 40702, 40725 through 40728, 40920.6, and 41508.

Clarity

PAR 1148.1 is written or displayed so that its meaning can be easily understood by the persons directly affected by them.

Consistency

PAR 1148.1is in harmony with and not in conflict with or contradictory to existing statutes, court decisions, or state or federal regulations.

Non-Duplication

PAR 1148.1 will not impose the same requirements as any existing state or federal regulations. The proposed amended rules are necessary and proper to execute the powers and duties granted to, and imposed upon, the South Coast AQMD.

Reference

In amending this rule, the following statutes which the South Coast AQMD hereby implements, interprets or makes specific are referenced: California Health and Safety Code sections 39002, 40001, 40406, 40702, 40440(a), and 40725 through 40728.5.

COMPARATIVE ANALYSIS

Under California Health and Safety Code section 40727.2, the South Coast AQMD is required to perform a comparative written analysis when adopting, amending, or repealing a rule or regulation. The comparative analysis is relative to existing federal requirements, existing or proposed South Coast AQMD rules and air pollution control requirements and guidelines which are applicable to oil and gas production activities. The comparative analysis will be provided in a future report