MEMORANDUM

To: OOGA Membership

From: OOGA & Trinity Consultants

Date: February 26, 2024

RE: Summary of Methane Rule Requirements

The purpose of this guide is to summarize the requirements of The Methane Rule established by the United States Environmental Protection Agency (US EPA). The information provided focuses primarily on the requirements of 40 CFR 60 Subpart OOOOc (OOOOc), but a summary of the regulatory changes established in 40 CFR 60 Subpart OOOOa (OOOOa) and 40 CFR 60 Subpart OOOOb (OOOOb) is also included.

This guide is meant to facilitate understanding of The Methane Rule by summarizing and paraphrasing the regulatory text. Use of this guide does not guarantee compliance with Subparts OOOOa, OOOOb, or OOOOc.

Using this Guide

This guide is divided into sections based on each equipment/activity type. Each section will contain the requirements for the equipment/activity type and outline potential compliance solutions/examples, if applicable. The requirements for Sweetening Units and Natural Gas Processing Plants are not addressed in this document.

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Compressors - §60.5392c, §60.5393c

- **Requirements**
  - Compressors at well sites – no applicable requirements
  - Compressors not located at well sites – wet seal centrifugal, dry seal centrifugal, and reciprocating
    - Must be routed to a control device or routed to a process with 95% reduction (see closed vent system/control device section of this memo) OR
    - Periodically measure the volumetric flow rate
      - Wet seal fluid degassing system – maintain seal vent flow rate at or below 3 scfm per seal
      - Dry seal – maintain seal vent flow rate at or below 10 scfm per seal.
      - Reciprocating – Maintain rod packing vent flow rate at or below 2 scfm per cylinder.

- **Compliance – Centrifugal Wet/Dry seals**
  - Must conduct volumetric flow rate measurements from seal vents every 8,760 hours of operation if not routed to a control device or process
  - Conduct measurements by any of the following
    - OGI or Method 21
      - If no leaks detected, can assume flow rate is zero
      - If leak detected must use temporary or permanent flow meter, or high volume sampler
    - Temporary or permanent flow meter
    - High volume sampler
  - If volumetric emissions measurement exceeds the applicable required flow rate:
    - Seal must be repaired within 90 days after the date the exceedance was measured
    - Seal must be re-monitored within 15 days after the repair to document that the rate is below the flow rate limit.
    - Can conduct repair during the next scheduled compressor station shutdown for maintenance, after scheduled blowdown or within 2 years of the flow rate exceedance, whichever is earliest if repair is:
      - Technically infeasible
      - Requires a vent blowdown
      - Requires a compressor station shutdown
      - Unsafe to repair during operation of the unit

- **Compliance - Reciprocating**
  - Must conduct volumetric flow rate measurements from rod packing vent every 8,760 hours of operation if not routed to a control device or process. Alternatively, replace the rod packing every 8,760 hours of operation
  - Conduct measurements by any of the following
    - Rod packing equipped with open-ended vent line
      - OGI or Method 21
        - If no leaks detected, can assume flow rate is zero
        - If leak detected must use temporary or permanent flow meter, or high volume sampler
      - Temporary or permanent flow meter
      - High volume sampler
    - Rod packing not equipped with open-ended vent line
      - Rod packing vent, distance piece vent, compressor crank case breather cap, or other vent emitting gas from the rod packing.

        - OGI or Method 21
        - If leak detected, must use temporary or permanent flow meter, or high volume sampler
    - If the rod packing vent flow rate measurement exceeds 2 scfm per cylinder:
        - Rod packing must be repaired or replaced within 90 days after the date the exceedance was measured
        - Rod packing vents must be re-monitored within 15 days after the repair to document that the rate is below 2 scfm per cylinder.
        - Can conduct repair or rod packing replacement during the next scheduled compressor station shutdown for maintenance, after scheduled blowdown or within 2 years of the flow rate exceedance, whichever is earliest, if repair or rod packing replacement is:
            - Technically infeasible
            - Requires a vent blowdown
            - Requires a compressor station shutdown
            - Unsafe to repair during operation of the unit

- **Examples of Compliant Compressors**
    - A midstream operator hires a contractor to visit their compressor stations annually with a FLIR camera to inspect the rod packing vents on their reciprocating compressors. During one of these annual visits, the contractor observes visible emissions and informs the operator. The operator uses a rotameter to verify that the flow rate is less than 2 scfm per cylinder.

    - A transmission pipeline installs orifice plate flow meters on the seal vents of each of their wet seal centrifugal compressors. The operator connects these flow meters to their Supervisor Control and Data Acquisition (SCADA) system and programs the data logger to record a measurement before each compressor passes 8,760 hours of operation. The SCADA system alerts the operator that one of the seal vents exhibited a flow rate of 3 scfm. The operator inspects and repairs a leak in the seal vent before the end of the month and clears the SCADA alert. After the alarm is cleared, the SCADA system is programmed to collect another flow measurement from the same seal vent within 15 days to confirm the repair.

Leak Detection and Repair - §60.5397c

- **Requirements**
  - Monitoring Frequency
    - Well sites – single wellhead and small sites (single wellhead well sites that do not contain more than one piece of major production/processing equipment and do not have any controlled storage vessels, control devices, natural gas-driven process controllers, or natural gas-driven pumps)
      - Quarterly Auditory/Visual/Olfactory (AVO) inspections
    - Well sites – multi-wellhead only well sites that do not contain any major production or processing equipment
      - Quarterly AVO inspections, and
      - Semiannual OGI or Method 21 Monitoring (4 < months between surveys < 7)
    - Well sites and Centralized Production Facilities (CPFs) that contain major production and processing equipment:
      - Bimonthly AVO inspections
      - Quarterly OGI or Method 21 Monitoring (at least 60 days apart)
    - Compressor Stations
      - Monthly AVO inspections
      - Quarterly OGI or Method 21 Monitoring (at least 60 days apart)
  - Develop fugitive emissions monitoring plan containing the following:
    - Frequency of conducting surveys
    - How survey was conducted (AVO, OGI, Method 21, or other detection methods)
    - If fugitive emissions detection equipment used, manufacturer and model number
    - Procedures and timeframes for identifying and repairing components detected to have a leak, including timeframes for the components that are unsafe to repair.
    - Procedures and timeframes for verifying repairs
    - Records that will be kept and their length of time they will be kept
    - If using OGI
      - verification that the OGI equipment meets required specifications
      - procedures that detail how the leak monitoring is conducted in accordance with the requirements
      - procedures to ensure all components are monitored, for example:
        - site map
        - observation path
        - write up of where the components are located and how they will be monitored
        - inventory of components
    - If using Method 21
      - verification that the monitoring equipment meets the required specifications
      - procedures that detail how the leak monitoring is conducted in accordance with the requirements
      - procedures for calibrating the instrument
      - list of components to be monitored
      - method of determining the location (tagging, process and instrumentation diagram, etc.)
      - plan for addressing components that require elevation more than 2 feet above a surface and are therefore difficult to monitor
      - plan to address components that involve exposure to immediate danger and are therefore unsafe to monitor

- Well closures
  - Submit well closure plan within 30 days of the cessation of production from all wells at a well site
  - Submit notification of intent to close the well site 60 days before beginning well closure activities.
  - Survey the well site using OGI including each closed well after completing well closure activities
    - Must eliminate any emissions and resurvey
    - Repeat until no emissions are detected by OGI
    - Include video of OGI survey with well closure plan

- **Compliance**
  - Monitor each component during each survey (excludes buried yard piping and associated components)
  - Conduct initial monitoring survey
    - Single wellhead sites and small sites – AVO within 90 days of the startup of production or by 90 days after the state plan submittal deadline, whichever is later
    - Multi-wellhead only sites, well sites or CPFs that contain major production and processing equipment, and compressor stations – OGI or Method 21 within 90 days of the effective date of the State plan or by 36 months after the state plan submittal deadline, whichever is later.
  - Subsequent monitoring – complete monitoring according to the schedule noted in the Requirements section.
    - Small well sites, well sites, or CPFs that contain major production and processing equipment – must also do the following during the AVO monitoring
      - Visually inspect thief hatches and other openings on uncontrolled storage tanks to verify they are they are kept closed and sealed at all times except during times of adding or removing material, inspecting, or sampling material, or during required maintenance operations.
      - Visually inspect separator dump valves
  - Repairs
    - First attempt at repair
      - No later than 15 calendar days after AVO detection
      - No later than 30 calendar days after OGI or Method 21 detection
    - Final repair
      - No later than 15 calendar days after first attempt at repair for AVO detection
      - No later than 30 calendar days after first attempt at repair date for OGI or Method 21 detection
    - Delay of repairs
      - For any of the following, repair must be completed during the next scheduled shutdown, after a scheduled vent blowdown, or within 2 years of detecting the emissions, whichever is earliest
        - Technically infeasible
        - Require vent blowdown
        - Compressor station shutdown
        - Well shutdown or shut-in
        - Unsafe to repair during operation of the unit
      - If repair requires replacement of component or part of component but the replacement cannot be acquired and installed within the repair timelines,

        - Required replacement must be ordered no later than 10 calendar days after the first attempt of repair
        - Must be repaired 30 calendar days after receipt of replacement component, unless the repair requires a compressor station or well shutdown
    - Conduct resurveys for all repaired components to document repair
        - Must use OGI or Method 21 except for those emissions identified using AVO detection methods. For fugitive emissions identified using AVO, can resurvey using AVO, OGI or Method 21

- **Examples of Compliant Fugitive Monitoring**
    - The operator of a small well site has the pumper assigned to the facility conduct quarterly AVO monitoring. As part of the monitoring, the pumper also does visual inspections of the thief hatches and other openings on the storage tanks that are vented to the atmosphere and the separator dump valves. On the scheduled day of AVO monitoring, the pumper does not observe any leaks during the inspection. On a monitoring form that will be kept on file the date of the inspection, the pumper documents what was inspected and that no leaks were found during the inspection.

    - A leak was detected from a heater treater valve during a semiannual OGI survey conducted by a third-party contractor at a multi-wellhead site. An operations/maintenance employee attempted an immediate repair that involved tightening a bolt. The third-party contractor immediately rechecks the valve with the OGI and verifies that the leak has been fixed. The third-party contractor provides a monitoring form/report to the operator that notes the component that was leaking, the first attempt of repair date, that a repair was made and resurvey was completed that verified the valve was no longer leaking.

Liquids Unloading from Gas Wells - §60.5390c

- **Requirements**
  - Liquid unloading operations that do not vent methane emissions to the atmosphere
    - Use Best Management Practices (BMPs) to minimize emissions if any unplanned venting occurs
  - Liquids unloading operations that vent methane emissions to the atmosphere
    - Develop, maintain, and follow BMP **OR**
    - Route to a control device or routed to a process with 95% reduction (see closed vent system/control device section of this memo)

- **Compliance**
  - BMP should include:
    - Steps that create a differential pressure to minimize the need to vent a well to unload liquids,
    - Steps to reduce wellbore pressure as much as possible prior to opening the well to the atmosphere,
    - Unloading liquids through the separator where feasible, and
    - Closing all wellhead vents to the atmosphere and returning the well to production as soon as practicable

- **Example of Compliant Liquids Unloading from Gas Wells**
  - The operator of a well site has a facility that does not have a control device on site. A BMP has been developed that incorporates all the required elements outlined in the rule and covers both planned and unplanned unloading events. Training is conducted with personnel on the BMP procedures. At the next liquids unloading event, personnel follow the BMP with no deviations. They document the date the venting occurred at the location and document each step in the BMP that was taken to minimize emissions. They note that there were no deviations from the BMP.

Associated Gas from Oil Wells - §60.5391c

- **Requirements**
  - Applies to the natural gas from wells operated primarily for oil production that is released from the liquid hydrocarbon during the initial stage of separation after the wellhead
    - Associated gas production begins at the startup of production after the flow back period ends.
    - Gas from wildcat or delineation wells is not associated gas.
  - Must recover the associated gas and do one of the following:
    - Route to sales
    - Use as onsite fuel
    - Use for some other purpose that a purchased fuel or raw material would serve
    - Reinject
  - Can route to a control device with 95% reduction if one of the following are met (see closed vent system/control device section of this memo)
    - Annual methane emissions are at 40 tons/yr or less at the initial compliance date **OR**
    - Demonstrate and certify that it is technically infeasible to recover the gas
      - Must provide detailed analysis certifying technical reasons why each method of recovery is technically infeasible
      - Must be certified by a professional engineer or other qualified individual who is an expert in the uses of associated gas
      - Analysis and certification must be repeated every 12 months
  - Flaring is allowed for:
    - Malfunction (24 hr/incident)
    - Repair/maintenance (24 hr/incident)
    - Production tests (24 hr/incident),
    - Interruptions in service of gas pipeline (30 days/incident),
    - Associated gas composition does not meet pipeline spec (72 hr/incident).
  - Venting is allowed for or
    - Safety purposes (12 hrs/incident)
    - Bradenhead monitoring (30 min/incident), and/or
    - Packer leakage testing (30 min/incident)

- **Example of Compliant Associated Gas from Oil Wells**
  - An oil producer uses a flare to manage the gas stream from a separator at a remote oil well. Every year, the oil producer hires an engineering firm to evaluate whether the gas stream could be used as a fuel source for the associated heater-treater. The engineering firm determines that the heat content of the gas would exceed the maximum design heat input capacity of the burner and could cause an explosion. The site does not include any other heaters and is not located near any gas gathering lines. The engineering firm also examines the geological properties of the well and determines that reinjecting gas will not be feasible. The engineering firm provides a detailed annual report to the producer for recordkeeping and submittal to the agency. The same engineering firm had previously certified that the flare was adequately sized to handle all vapors from the separator without smoking. The flare is equipped with a pilot monitoring device.

Process Controllers - §60.5394c

- **Requirements**
  - Does not apply to process controllers that are emergency shutdown devices or those not natural gas-driven
  - Natural gas driven process controllers at a well site, CPF, or compressor station must have zero methane emissions
    - Route process controller emissions to a process
    - Use self-contained natural gas-driven process controllers (releases gas into the downstream piping and not to the atmosphere)

- **Compliance monitoring**
  - Process controllers routed to process
    - See closed vent system/control device section of this memo
    - Annually – Inspections for defects
  - Self-contained natural gas driven process controllers
    - Initial – no detectable emissions– OGI or Method 21
    - Quarterly – no detectable emissions- OGI or Method 21

- **Example of Compliant Process Controllers**
  - A midstream operator already relies on a contractor to conduct quarterly OGI surveys for all piping components. The operator has instructed the contractor to include all self-contained process controllers in the quarterly survey.

Pumps - §60.5395c

- **Requirements**
  - Does not apply to pumps that are not driven by natural gas or pumps that operate less than 90 days a calendar year
  - Natural gas driven pumps at a well site, CPF, or compressor station must have zero methane emissions
    - Sites with electrical power and sites with no electrical power with 3 or more natural gas-driven diaphragm pumps
      - Route to process or use other means to have zero emissions
    - If no electrical power at site and fewer than 3 natural gas driven diaphragm pumps
      - Route to a process if Vapor recovery unit (VRU) is on site
      - If VRU not onsite, route to a control device for 95% control if one is onsite
      - If VRU not onsite, and control device is unable to achieve 95% control
        - Still route to control device, but certify there is no VRU onsite and there is no control device onsite capable of achieving a 95% reduction
      - No VRU and no control device onsite
        - Certify neither are on site
        - If either is subsequently installed, must route pump emissions within 30 days of startup.
        - Can conduct an engineering assessment to identify that routing to a VRU or control device is technically infeasible.

- **Compliance**
  - Monitoring
    - Natural gas-driven pump routed to process
      - See closed vent system section of this memo
      - Annually – visual inspections for defects
      - Component repaired or replaced or connection unsealed – OGI or Method 21
    - Natural gas-driven pump routed to a control device
      - See control device section of this memo
  - Engineering assessment of technical infeasibility
      - Must be conducted and certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the facility
      - Must include
        - safety considerations
        - distance from the control device or process
        - pressure losses and differentials in the closed vent system
        - the ability of the control device or process to handle the pump designated facility emissions which are routed to them

- **Example of Compliant Pumps**
  - A producer operates a remote well site without access to electrical power. The glycol dehydrator operates using a natural gas-driven diaphragm pump. No other natural gas-driven pumps are located at the site. The producer has not historically operated any control devices at the site but is planning to install a flare to reduce emissions from storage vessels. The producer designs and positions the flare such that emissions from the natural gas-driven diaphragm pump will be collected and controlled along with the storage tank emissions.

Storage Tanks - §60.5396c

- **Requirements**
  - Single storage vessel or tank battery (group of all storage vessels that are manifolded together for liquid transfer) with a potential to emit (PTE) greater than 20 tons/yr of methane emissions
    - Capture and reduce methane emissions by 95%
      - See closed vent system/control device section of this memo
    - Controls no longer required when uncontrolled actual emissions are less than 14 tons/yr of methane as determined monthly for 12 consecutive months
    - If methane emissions increase to 14 tons/yr or more of methane, must comply with reducing methane emissions by 95% within 30 days
  - Removing tanks from service
    - Completely empty and degas so that the tank no longer contains liquids
    - Tank is still considered empty if liquid is left on walls, as bottom clingage or in pools due to floor irregularity
    - Any tank taken out of service that is part of tank battery must be disconnected by isolating from the battery such that it's no longer manifolded to the tank battery by liquid or vapor transfer
  - Returning tanks to service
    - Assess emissions to determine if the greater than 20 tons/yr of methane emissions

- **Examples of Compliant Associated Storage tanks**
  - An oil producer collects a pressurized sample of the liquids entering a battery of storage tanks at an existing oil well and hires a lab to conduct an extended hydrocarbon analysis. The producer also reviews production volumes for the past month to determine the maximum average daily throughput. The producer purchases software to calculate methane emissions from the battery including flashing, working, and breathing losses and generates a report documenting that methane emissions are less than 20 tons per year.

  - A midstream operator uses engineering documentation to confirm the maximum gas throughput for an existing compressor station and uses this throughput to calculate the associated maximum average daily throughput of condensate and pipeline liquids collected in a battery of storage tanks. The operator uses a recent extended hydrocarbon analysis from a pressurized liquid sample along with the maximum average daily throughput as inputs to a software model capable of estimating methane emissions from flashing, working and breathing losses. The operator calculates methane emissions exceeding 20 tons per year and proceeds to install a closed vent system and vapor combustor to reduce emissions from the battery of storage tanks.

Closed vent system/Control Device - §60.5416c, §60.5417c

- **Requirements**
  - **Equipment routed to closed vent system (CVS)**
    - Each CVS must be designed and operated to capture and route all gases, vapors, and fumes to a process or to a control device and comply with an emissions limit of no identifiable emissions.
    - LDAR monitoring frequency same as frequency required for LDAR surveys (see leak detection and repair section of this memo)
    - Design must be certified by an engineer.
    - If the CVS is equipped with a bypass to atmosphere, the bypass must
      - include a flow monitor
      - sound an alarm to alert personnel that a bypass device is open and stream is being or could be diverted from control device or process and sent to the atmosphere
      - use a car-seal or lock-and-key type configuration to secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position
  - **Equipment routed to control device**
    - Combustor
      - Continuously monitor combustion temperature
      - Continuously monitor pilot status
      - Continuously monitor flow rate
      - Monthly Method 22 visible emissions check or surveillance camera
      - Initial stack test and 5-year repeat testing
      - Monitor during OGI and AVO surveys
    - Route into flame zone of process heater along with primary fuel
    - Flare
      - Maintain net heating value (NHV)
      - Continuously monitor pilot status
      - Continuously monitor flow rate
      - Monthly Method 22 visible emissions check or surveillance camera
      - Monitor during OGI and AVO surveys

Summary of Regulatory Changes

OOOOa

- The applicability dates of OOOOa have been revised to apply to oil and natural gas facilities that commence construction, modification or reconstruction **after September 18, 2015**, and **on or before December 6, 2022.**
- The rule has been updated to correct certain inconsistencies between the VOC and methane standard resulting from the disapproval of the 2020 Policy Rule and certain determinations from the 2020 Technical Rule:
    - methane remains a regulated pollutant,
    - applicability remains for the transmission and storage sector,
    - fugitive emissions monitoring exemption for low production well sites and gathering and boosting facilities have been removed.
- The rule now incorporates Super Emitter Program requirements.

OOOOb

- Applies to oil and natural gas facilities that commence construction, modification, or reconstruction **after December 6, 2022**.
- Includes new requirements to reduce methane emissions by using "best system of emission reduction" (BSER)
- Eliminates routine flaring from oil well by requiring gas to be routed to a sales line, used as an onsite fuel source or another useful purpose, or reinjected into the well or another well upon start-up.
- Incorporates Super Emitter Program requirements.
- Changes to storage vessel applicability
    - Adds storage tank battery to the definition of storage vessel
    - Tank batteries with total potential methane emissions greater than or equal to 20 tons/yr must reduce VOC and methane emissions by 95%.
    - Tanks battery facilities with emissions less than 6 tons/yr VOC and less than 20 tpy of methane emissions can avoid OOOOb applicability if they comply with an air permit that as legally and practically enforceable (LPE) limits
        - Production limits
        - Performance testing of emissions controls
        - Ongoing monitoring, recordkeeping, and reporting

Super Emitter Program

- Applies to events resulting in methane emissions of 100 kg/hr or greater based on remote detection methods.
- This program is applicable to OOOO, OOOOa, OOOOb, and OOOOc affected facilities.
- Super emitter events may be submitted to EPA for review by certified third party notifier.
- Events must be detected by satellite detection, remote-sensing equipment on aircraft, or mobile monitoring platforms.
- The owner/operator must initiate an investigation within 5 calendar days and complete the investigation with 15 days of receiving notice from EPA.
- If fugitive release is confirmed, must complete repairs in accordance with rule.
- A follow-up report is required for investigation and follow-up actions.