



Ozone Precursor Rule (20.2.50 NMAC)

Initial (General) Compliance Guidelines

New Mexico Environment Department, Air Quality Bureau

Applicability and Scope

As of the effective date, August 5, 2022, all sources within the oil & gas sector – except refineries, oil transmission pipelines, natural gas transmission pipelines (unless at transmission compressor stations), and saltwater disposal facilities – in eight counties are subject to the Ozone Precursor Rule (“Part 50”). The eight counties include Chaves, Doña Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan and Valencia. Counties may be added at a later date (by amending the rule) but sources subject to Part 50 as of the effective date may only avoid applicability in the future by obtaining a federally enforceable limit (e.g., in a permit issued by the Bureau) on their potential to emit (“PTE”) below applicability thresholds.

PTE is defined as “the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design.” As part of its design, sources may reduce PTE by installing and operating air pollution control equipment, restricting hours of operation, or restricting the types or amounts of materials combusted, processed or stored. All such claimed reductions must be based on federally enforceable requirements.

The sources that are subject to Part 50 include oil and gas production and processing equipment at facilities that extract, collect, separate, dehydrate, store, process, transport, transmit or otherwise handle hydrocarbon liquids or produced water at well sites, tank batteries, gathering/boosting stations, natural gas processing plants and transmission compressor stations – up to the point of the local distribution company custody transfer station. Part 50 does not regulate the local distribution system. Small business facilities (independently owned or operated by a company not a subsidiary or division of another business, that employ no more than 10 employees and have gross annual revenue less than \$250k) are only subject to Sections 125 and 127, with some exceptions found in Section 125.

Pollutants of Concern

Pollutants of concern are those pollutants which contribute to ozone formation: total oxides of nitrogen (“NO_x”) and volatile organic compounds (“VOC”).

General Requirements

1. Affected sources must be operated and maintained consistent with manufacturer specifications or with good engineering and maintenance practices (“alternative specifications”). Manufacturer or alternative specifications must be kept on file and made available to the Department upon request.
2. Affected sources must be operated and maintained consistent with good air pollution control practices for minimizing VOC and NO_x, including during periods of startup, shutdown and malfunction (“SSM”). During SSM events, the owner/operator must reduce emissions to the greatest extent possible; this does not require reductions beyond the applicable standards in Part 50.
3. For good cause, the Department may require the owner or operator to verify data or information by retaining a third party at the owner or operator’s expense. The owner or operator must then submit a report to the Department and implement the recommendations, as approved by the Department.
4. When modifying an existing source, whether or not emissions or throughput increase, applicability must be determined for the modified source.

General Monitoring Requirements

1. The use of the term, “monitoring” in Part 50 may refer to testing, monitoring or inspection.
2. The owner or operator is not required to restart shut down units only to perform required testing, monitoring or inspection. If a unit is shut down at such time, the shutdown (date/time range for shutdown) shall be recorded for that equipment. Testing, monitoring or inspection should occur as soon as possible after the unit is restarted.

General Recordkeeping Requirements

1. Electronic records of all monitoring events must be maintained by the owner or operator for 5 years.
2. The time/date/location stamp requirement for recordkeeping does not require technology until August 5, 2024. By August 5, 2023, the Department will publish a list of approved technologies to use after that time. Until that time, date, time and location may be entered manually – on paper by the person conducting the monitoring or entered into a spreadsheet or form electronically.
3. Each annual compliance database report (“CDR”) generated must be maintained by the owner or operator for 5 years.

General Reporting Requirements

1. Upon request for information from the Department, the owner or operator must submit a complete response within 3 business days. If multiple facilities are included in the request, additional time will be given as appropriate.
2. The response will include the CDR to which the information request correlates and must be uploaded to the Department’s Secure Extranet Portal, unless otherwise requested by the Department.

General Timing of Requirements – See individual sections for more details

Beginning August 5, 2022:

- Perform Method 22 observations for flares or enclosed combustion devices when visible emissions are observed. (Section 115)
- Well workovers must use best management practices to minimize emissions. (Section 124)

By August 12, 2022 and weekly thereafter:

- For well sites, tank batteries, gathering/boosting stations, natural gas processing plants, transmission compressor stations with annual average daily production or average daily throughput greater than 10 barrels of oil per day or greater than 60,000 scfd of natural gas must conduct AVO inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping and associated equipment. (Section 116)

By September 5, 2022 and monthly thereafter:

- Inspect control devices visually or with federally approved inspection methods. (Section 115)
- Comply with the standards for equipment leaks in Part 50, Section 116 or a program that meets the requirements of NSPS Subpart OOOOa. (Section 116)
- For well sites, tank batteries, gathering/boosting stations, natural gas processing plants, transmission compressor stations with annual average daily production or average daily throughput less than or equal to 10 barrels of oil per day or less than or equal to 60,000 scfd of natural gas must conduct AVO inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping and associated equipment. (Section 116)
- Conduct OGI or EPA Method 21 inspection at gathering/boosting stations with PTE \geq 25 tpy VOC. (Section 116)

By November 3, 2022

- Conduct an evaluation to determine applicability to Part 50, Section 116.C(e)(3) for existing well sites. Conduct the evaluation for new well sites within 30 days of construction. (Section 116)

By November 5, 2022 and quarterly thereafter:

- Perform Method 22 observations for flares or enclosed combustion devices while the pilot or auto-igniter flame is present. (Section 115)
- Conduct OGI or EPA Method 21 inspection at gathering/boosting stations with PTE < 25 tpy VOC. (Section 116)
- Conduct OGI or EPA Method 21 inspection at transmission compressor stations (or in compliance with NSPS Subpart OOOOa as in effect August 5, 2022. (Section 116)
- Conduct OGI or EPA Method 21 inspection at well sites within 1,000 feet of an occupied area. (Section 116)

By January 1, 2023:

- Owner or operator of an existing natural gas-fired spark ignition engine must complete an inventory of all existing engines subject to Part 50, along with a schedule for assuring compliance with the requirements in 20.2.50.113.B(2). (Section 113) (New natural gas-fired spark ignition engines must meet standard upon startup)

By February 1, 2023:

- Owner or operator must conduct an initial compliance test, demonstrating compliance with the emission standards for engines and turbines operated 500 hours per year or more for sources identified in 20.2.50.113.B(2) and (7) NMAC; or, if installed more than 180 days after the effective date, within 60 days after achieving maximum production rate, but no later than 180 days after initial startup. (Section 113) Periodic testing of such sources is required annually (once per calendar year). Testing required by NSPS (40 CFR 60), Subparts GG, IIII, JJJJ or KKKK) or MACT (40 CFR 63), Subpart ZZZZ) may satisfy these testing requirements if completed at least once per calendar year and testing meets the requirements of 20.2.50.113 NMAC.

By February 5, 2023:

- OGI or EPA Method 21 inspection of well sites that are inactive as of August 5, 2022. For well sites that become inactive after August 5, 2022, OGI or EPA Method 21 inspections of well sites within 30 days of the well becoming inactive. (Section 116) Annual inspections must be conducted thereafter.
- Produced water management units and associated storage vessels must meet emission standards. (Section 126)

By July 1, 2023:

- Owners/operators of existing stationary natural gas-fired combustion turbine must complete an inventory of all existing turbines subject to Part 50, along with a schedule for assuring compliance with the requirements in 20.2.50.113.B(7). (Section 113) New natural gas-fired combustion turbines must meet standard upon startup.
- Owners/operators of pneumatic controllers must determine the total controller count for all controllers subject to each table separately at all of the owner or operator's affected facilities that commenced construction prior to August 5, 2022. (Section 122)

By August 5, 2023:

- Department will publish a list of approved technologies to comply with the time/date stamp and GPS location requirements for testing, monitoring and inspection events.

By January 1, 2024:

- 30% of existing natural gas-fired turbines meet standard. (Section 113)
- OGI or EPA Method 21 inspections of 30% of existing wellhead-only facilities must be completed. Annual inspections required thereafter. (Section 116)
- 25-80% of (previously) natural gas-driven pneumatic controllers must be converted to non-emitting controllers, depending on the total historic percentage of non-emitting controllers at

the facilities and depending on the type of facility in which the controllers are found. (Section 122, Tables 1 and 2) New pneumatic controllers must have an emission rate of zero starting August 5, 2022.

By July 1, 2024:

- Owner or operator must generate a CDR on all assets under its control. A new report must be generated annually by July 1 thereafter.

By August 5, 2024:

- Sources must develop and implement a data system capable of storing required information for each source. From the record of data, the owner or operator must generate a CDR, which must be maintained by the owner or operator and submitted to the Department upon request. Identifying information (see 20.2.50.112.A(3)(a-f) for each piece of equipment subject to Part 50 must be maintained in the record of data, as well as each monitoring and testing event data for such equipment. Monitoring/testing data must be uploaded to the system no later than 3 business days after the monitoring event and when final testing reports are received. Sources must use the approved technology for time/date stamp and GPS location requirements.
- Owner or operator of an existing centrifugal compressor with wet seals must control VOC emissions from the fluid degassing system by at least 95%. New centrifugal compressors with wet seals must control VOC emissions from the fluid degassing system by at least 95% upon startup. (Section 114)
- Owner or operator of an existing well site or standalone tank battery must conduct OGI or EPA Method 21 inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping and associated equipment. (Section 116) Period inspections thereafter required as follows:
 - Annually – facilities with PTE <2 tpy VOC
 - Semi-annually – 2 tpy VOC ≥ facility PTE < 5 tpy PTE
 - Quarterly – facilities with PTE ≥ 5 tpy VOC
- Natural gas wells for which liquid unloading operations result in venting of natural gas must implement best management practices. (Section 117)
- Existing glycol dehydrators with PTE equal to or greater than 2 tpy VOC must achieve minimum combined capture and control efficiency of 95%. New glycol dehydrators with PTE equal to or greater than 2 tpy VOC must achieve the same level of efficiency upon startup. (Section 118)
- Hydrocarbon liquid transfers at certain existing facilities with one or must control VOC emissions by at least 95% during transfer; if using a combustion control device, it must have a minimum design combustion efficiency of 98%. New hydrocarbon liquid transfers at these facilities must control to the same level upon startup. (Section 120) Hydrocarbon liquid transfers at existing gathering and boosting stations (and associated tank batteries) without any controlled storage vessels are on a compliance schedule found in Section 123.
- Affected pipeline pig launching and receiving operations (PTE equal to or greater than 1 tpy VOC) must capture and reduce VOC emissions by at least 95%. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98%. (Section 121)

- Existing produced water management units must control pursuant to Section 123 requirements or submit a VOC minimization plan to the department. (Section 126) New produced water management units must control pursuant to Section 123 requirements upon startup.

By January 1, 2025:

- 30% of existing natural gas-fired spark ignition engines meet emission standard (based on 2023 inventory). (Section 113)
- 65% of existing wellhead-only facilities must be OGI or EPA Method 21 inspected. Annual inspections required thereafter. (Section 116)
- 30% of a company's existing storage vessels must have combined capture and control of VOC efficiency of at least 95%. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98%. (Section 123) New storage vessels must have this capture and control efficiency upon startup.

By August 5, 2025:

- Existing closed vent systems assessed and certified. New closed vent systems assessed and certified within 90 days of startup. (Section 115)
- Install a backup control device or redundant VRU at sites that already have a VRU installed as of August 5, 2022. (Section 115)
- Existing natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hr must comply with emissions standards for NO_x and CO. (Section 119) New natural gas-fired heaters with rated heat input equal to or greater than 20 MMBtu/hr must comply upon startup.
- 100% of existing natural gas-driven pneumatic pumps must comply with emission standards. (Section 122) New natural gas-driven pneumatic controllers or pumps must comply upon startup.

By January 1, 2026:

- 100% of existing wellhead-only facilities must be OGI or EPA Method 21 inspected. Annual inspections required thereafter. (Section 116)
- 65% of existing natural gas-fired turbines meet standard. (Section 113)
- Well recompletions and new wells at an existing wellhead site must collect and control emissions from each flowback vessel. If a thermal oxidizer or enclosed combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. (Section 127) New wells at new wellhead sites are subject to these requirements as of the effective date or when completed/recompleted.

By January 1, 2027:

- 65% of existing natural gas-fired spark ignition engines must meet standard. (Section 113)
- 65-95% of (previously) natural gas-driven pneumatic controllers must be converted to non-emitting controllers, depending on the total historic percentage of non-emitting controllers at the facilities and depending on the type of facility in which the controllers are found. (Section 122, Tables 1 and 2) New pneumatic controllers must have an emission rate of zero starting August 5, 2022.

- 65% of a company's existing storage vessels must have combined capture and control of VOC emissions of at least 95%. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98%. (Section 123) New storage vessels must have this capture and control efficiency upon startup.

By January 1, 2028:

- 100% existing natural gas-fired turbines meet standard. (Section 113)

By January 1, 2029:

- 100% of existing natural gas-fired engines meet standard. (Section 113)
- 100% of a company's existing storage vessels must have combined capture and control of VOC emissions of at least 95%. If a combustion control device is used, the combustion device must have a minimum design combustion efficiency of 98%. (Section 123) New storage vessels must have this capture and control efficiency upon startup.

By January 1, 2030:

- 80-98% of (previously) natural gas-driven pneumatic controllers must be converted to non-emitting controllers, depending on the total historic percentage of non-emitting controllers at the facilities and depending on the type of facility in which the controllers are found. (Section 122, Tables 1 and 2) New pneumatic controllers must have an emission rate of zero starting August 5, 2022.