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To:	Methanestrategy, NM, NMENV; WasteRule, EMNRD, EMNRD; NMOAI, NMENV
Cc:	Ben Shepperd PBPA
Subject:	[EXT] PBPA Comments on NMED and EMNRD draft rules on methane
Date:	Wednesday, September 16, 2020 2:10:55 PM
Attachments:	PBPA Comments on NMED and EMNRD Methane Draft Rules.9.16.2020.pdf

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Dear Deputy Director Polak and Specialist Bisbey-Kuehn,

Attached, please find the Permian Basin Petroleum Association's written comments on the proposed draft rules developed by the New Mexico Energy, Minerals and Natural Resources Department and the New Mexico Environment Department, which are being recommended in the New Mexico Administrative Code at 19.15.7, 18, 19, 27 & 28, and 20.2.50, respectively.

Please let us know if you have any questions.

Thank you,

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PERMIAN BASIN
PETROLEUM ASSOCIATION

September 16, 2020

Submitted via Electronic Mail

Liz Bisbey-Kuehn
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New Mexico Environment Department
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Santa Fe, NM 87505

and

Tiffany Polak
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Energy, Minerals, and Natural Resources Department
1220 South St. Francis Dr.
Santa Fe, NM 87505

Re: Comments on the New Mexico Energy, Minerals and Natural Resources Department Draft Methane Rule at NMAC 19.15.7, 18, 19, 27 & 28 and the New Mexico Environment Department Draft Ozone Precursor Rule at NMAC 20.2.50.

Deputy Director Polak and Specialist Bisbey-Kuehn:

The Permian Basin Petroleum Association ("PBPA") and its member companies appreciate the opportunity to comment on the proposed draft rules developed by the New Mexico Energy, Minerals and Natural Resources Department ("EMNRD") and the New Mexico Environment Department ("NMED"), which are being recommended in the New Mexico Administrative Code ("NMAC") at 19.15.7, 18, 19, 27 & 28 and 20.2.50, respectively. Included herein is an executive summary of our comments, along with copies of the draft rules with recommendations and notes included ("Redlines"). The included Redlines offer detailed recommendations on changes to the draft rules along with specific comments as to reasons for changes or concerns.

PBPA is the largest regional oil and gas association in the United States. Since 1961, the PBPA has been the voice of the Permian Basin oil and gas industry. The PBPA's mission is to promote the safe and responsible development of our region's oil and gas resources while providing legislative, regulatory and educational support services for the petroleum industry. The

PBPA membership includes the smallest exploration and service companies as well as some of the largest companies with world-wide operations. The Permian Basin is the largest inland oil and gas reservoir and the most prolific oil and gas producing region in the world.
While PBPA is greatly supportive of improvements to the regulatory framework for oil and gas operations in New Mexico, as presented, the draft rules contain multiple concerning aspects.

- There are several definitions, or lack of certain definitions, in the draft rules which if not remedied will cause confusion, ineffectiveness, or which do not work towards preventing waste or lowering emissions.
- As drafted, the rules create redundant and conflicting requirements with other state and federal rules.
- There should be more time allowed for the required retrofitting or installation of new equipment at existing facilities.
- The draft rules are overly prescriptive and will limit innovation instead of encouraging it.
- The unduly burdensome monitoring, notification, recordkeeping and reporting requirements will be counterproductive, ineffective, cost-prohibitive, actually create a lack of transparency, and do not prevent waste or lower emissions.
- The use of EMITT scanner codes will be cost-prohibitive, ineffective, and will result in the shutting in of great amounts of production in the state without much, if any, prevention of waste or lowering of emissions.
- Compliance timelines and timelines for repairs and reporting do not appear to take into consideration real world conditions.
- The impact to the New Mexico economy has not been taken into consideration in the drafting of these rules.
- The requirements for evaporative ponds make such techniques, which advanced computations have shown have almost non-existent emissions of VOCs, no longer viable.
- The way "credible information" is allowed by the draft rules creates a presumption of noncompliance or, essentially, authorizes agencies to presume guilt until an operator proves its own innocence.

Each of the above are discussed in detail in the included Redlines and, where possible, alternative language is provided. As to some areas where alternative language may not be possible, this letter serves to provide a better understanding as to PBPA's concerns.

PBPA has not provided Redlines for Part 28 of Title 19, Chapter 15. While we have a wide and diverse membership, including upstream operators, service companies and midstream operators, in consulting with our midstream members and other midstream associations we have concluded they are better suited to provide detailed comment for Part 28.

Through these consultations, however, it is our position that several of the provisions in Part 28 require further clarification and additional analysis from a midstream perspective. For example: "continuous press monitoring" is not clearly defined in 19.15.28.20; requiring use of a portable flare stack during blowdown in 19.15.28.19 is burdensome and impractical if required every time an operations team needs to work on a line; and, the Location & Marking requirements in 19.15.28.13 are out of step with annual and bi-annual requirements of other states. (For example, North Dakota provides operators 180 days to submit a GIS digitally formatted as-built map after the in-service date.)

PBPA encourages EMNRD to review the provisions identified above and work with midstream operators on these and other modification recommendations regarding Part 28. EMNRD should also consider whether the New Mexico Pipeline Safety Bureau might be better suited for regulating the safety, construction, inspection and monitoring of pipelines.

Oil Conservation Division

Operator's Monthly Report (Form C-115) and Vented and Flared Natural Gas (Form C-115B) (19.15.7.24.B and 19.15.7.25 NMAC)

EMNRD has proposed reducing the timeline for submitting C-115 reports from forty-five (45) days to thirty (30) days. The loss of fifteen (15) days significantly inhibits operators from conducting a self-audit prior to filing. PBPA is concerned that this time reduction will result in errors to production reports which are vital to the State when projecting revenue. Therefore, PBPA recommends that the C-115 reports continue to be due 45 days following the production month.

PBPA supports EMNRD in its goal to increase reporting of vented and flared natural gas, however, the proposed form C-115B will not provide the clarity EMNRD seeks. Venting and flaring happens mostly during the production phase of a facility. These volumes should be captured on a form C-115 which is also the State's production form. Reporting what has been produced and sold along with what has been vented or flared provides EMNRD and the public with an accurate assessment of waste which may be occurring.

Venting and Flaring (19.15.27.8.B and D NMAC)

PBPA supports with modifications of notifying EMNRD of an emergency or malfunction during the production phase (19.15.27.8.D(4)). EMNRD's Release rule (19.15.29 NMAC) provides a workable timeline for reporting which

balances the need of the operator to remedy the situation quickly while still providing EMNRD with the information in a reasonable amount of time. PBPA's Redlines reflect that balance.

Notification of an emergency or malfunction during drilling should comply with the applicable requirements of 19.15.29 NMAC. Modern well drilling takes about ten (10) days and given advances in technology emergencies and malfunctions rarely occur. In those limited situations that an emergency or malfunction does occur the operator must report to EMNRD per 19.15.29 NMAC.

Venting and Flaring (19.15.27.8.E NMAC)

The proposed draft rule creates twenty (20) reporting categories for vented and flared volumes. While PBPA supports increasing the types of events reportable to EMNRD, 20 categories is onerous, will lead to inaccuracies and does not prevent waste. First, accounting software is not designed for 20 additional categories and if required upgrades will require eighteen (18) to twenty-four (24) months. Second, as previously discussed PBPA believes reporting vented and flared volumes on form C-115 provides the most accurate information on volumes of wasted natural gas. Finally, a number of the categories are not waste. Examples include pilot gas for combustion devices and purge gas to test or fuel combustion devices are beneficial uses of gas.

New Mexico Environment Department

Effective Date (20.2.50.5 NMAC)

Oil and Natural Gas Regulation for Ozone Precursors is currently written to require subject wellhead sites to be compliant upon publication by the New Mexico Register except for certain provisions, such as emission standards for glycol dehydrators at 20.2.50.15.B(1). PBPA has grave concerns about imposing the rule's costly and burdensome requirements immediately upon publication. PBPA proposes, instead, a tiered effective date approach whereby the sites emitting the most must come into compliance and those wellhead sites emitting the least have the longest amount of time to comply.

PBPA proposed effective date:

- One year for wellhead sites emitting 25 tpy or greater of VOCs
- Two years for wellhead sites emitting 15-25 tpy of VOCs
- Three years for wellhead sites emitting less than 15 tpy of VOCs
- Immediate compliance for new wellhead sites emitting VOCs

PBPA members estimate the costs of implementing the rule as written will be approximately $27,000 per wellhead site. This will lead to production being prematurely abandoned and less revenue to the State at a time when New Mexico agencies are already having to reduce costs by 5% because of the budget deficit. PBPA's proposal addresses the need to limit emissions while at the same time protecting State revenues from a further decline.

Equipment Monitoring Information Tracking Tag (20.2.50.12.A(6) NMAC)

The Equipment Monitoring Information Tracking Tag (EMITT) section contains many issues that will make compliance as prescribed by NMED impossible. Below PBPA provides an in-depth analysis of EMITT and why requiring an equipment database is a better tool for both operators and the NMED.

Personnel Time Requirements

The field personnel time required to locate an EMITT, scan the EMITT, perform the necessary periodic task (such as leak monitoring), enter data into an electronic device, and move to the next EMITT (together an EMITT 'task') will require an extensive amount of time from operator's field personnel. It is estimated that an EMITT task will require five minutes with no additional issues (such as a leak located). While five minutes per EMITT sounds very reasonable, wellhead sites range from as few as six pieces of equipment that require an EMITT, to over 100 pieces of equipment requiring an EMITT. Some operators with large wellhead sites may have over 200 pieces of equipment that require an EMITT.

At a wellhead site with 18 EMITT, a battery will require a minimum of one hour to perform one of the periodic tasks prescribed by 20.2.50, assuming there are no issues to address. A battery with 100 tags will require more than one 8-hour working day to complete, not including any time to travel to the battery. An operator with 25 wellhead sites will likely need to add at least two dedicated employees to perform the prescribed periodic weekly, monthly, quarterly, and semi-annual tasks proposed throughout all of section 20.2.50, because if an operator's field personnel attempted to perform these tasks, they would be unable to maintain the wellsite production equipment; potentially leading to catastrophic fluid spills or fires.

The five-minute estimated time to complete an EMITT task is predicated on personnel being able to locate and scan the EMITT quickly. Physically small sized EMITT placed on small sized equipment such as pneumatic devices will be hard to locate and hard to scan due to the physical size of the EMITT thus increasing the time required to complete a task—small tags require the

scanning device to be very close to the tag and can still be difficult to scan. Setting up the EMITT for an operator's wellhead sites will also require a lot of time. It is difficult to estimate the time required to complete EMITT set-up which will include equipment inventory/data collection, EMITT encoding for each tag, and EMITT application to equipment. A minimum of one hour of labor to set-up each EMITT (not including any travel) is estimated. During the EMITT set-up process the potential for good-faith errors due to the large amount of data to be gathered are unacceptably high.

EMITT Fiscal Costs

The costs to establish the EMITT system will vary across the industry. Since environmental compliance and information technology personnel will be required, hourly costs are estimated at a minimum of $125 per hour. Annual database maintenance are estimated at four hours per week, 208 hours per year. Using the estimate of $125 per hour, cost to an operator are $26,000 per year only for maintenance.

Lease operators are estimated at approximately $35 per hour. On this basis, one facility with 18 EMITT will cost an operator $3,465 per year based on 52 weekly AVO, 12 monthly operation and maintenance inspections, and two semiannual LDAR inspections (66 total). This cost assumes that each inspection will require one hour of personnel time and there are no issues that will take additional time. Twenty-five (25) wellhead sites that have 18 EMITT will cost an operator a minimum of $86,250. These costs do not include other costs such as OGI camera costs (purchase $85,000, vendor is $200/hour), tag printing cost, or travel time between wellhead sites.

Since there are a wide range of wellhead sites, it is necessary to include an estimate of a facility with 100 EMITT. 100 EMITT will cost an operator $19,250 per year. 25 wellhead sites with 100 EMITT will cost an operator $481,250. Using the previous examples, 25 wellhead sites, each with 18 EMITT will cost an operator $56,250 to set up EMITT. 25 well head sites with 100 EMITT will cost an operator $312,500. And these are only costs to set up the EMITT as prescribed by 20.2.50.12.A.6.

As detailed in 20.2.50.12.A.6 (a) through (e), each EMITT requires five data fields to be displayed when scanned: Unique unit ID, UTM location coordinates, type of unit, potential to emit in pounds per hour & tons per year, and the amount of controlled potential to emit if the unit is a control device. The EMITT can be scanned by any person with the proper hand held device. A QR code can be read by all modern smart phones. Allowing any person to access an operator's wellhead site information compromises the privacy of an operator's data. Furthermore, the potential to emit of some equipment could

potentially compromise confidential business information regarding rate of production and the longevity of the wellsite.

Encouragement of Trespassing

Further, the presence of EMITT could encourage trespassing. With the provisions of 20.2.50.27, operators are concerned that trespassers who are not trained to be at a wellhead site will be encouraged to risk their personal safety. The safety risk of serious injury or death to untrained trespassers due to rotating or heavy moving parts, heights, pressurized gasses, and vessels with explosive atmospheres at operating wellhead sites is incredible and disturbing. The risk is increased exponentially if deadly H2S gas is present at the wellsite.

Durability of Tags

There are concerns about the durability of the EMITT. New Mexico has a difficult climate including wide seasonal temperatures, violent storm events, year-round high wind speeds, etc. Many areas also have excessive blowing sand and salt. Field personnel have expressed that it is difficult to maintain required labels for tanks even using the most durable labels available. Since it is already difficult to maintain labels on equipment, EMITT will have similar issues. More concerning is despite any good faith effort to prevent EMITT loss, missing labels can put operators in violation if a label is lost and an inspector tries to scan the unit. In addition, the loss of labels due to poor outdoor durability will cause difficulty during any monitoring event the operator tries to conduct.

Use of QR Codes

The QR code system is an easy to use system that does not require specialized equipment when scanned. The QR codes are cost effective at $0.20 to $1.00 each, can store up to 4,000 characters of information, and they are easily scanned by modern smartphones. However, there are several issues that the NMED may not have anticipated. In order to display the five required data fields when scanned, a QR code must be custom encoded and printed for each piece of equipment requiring an EMITT. In order to do this, all data must be collected and organized before being printed by a specialized manufacturer. After the EMITT have been custom printed, they must be applied to the correct equipment that they were encoded for.

As noted before, there is incredible potential for good faith error when creating unique QR tags. Getting custom QR tags printed with the five fields of data is also problematic because the tag is encoded to include potential to emit information that will change over time as the production at the battery

changes with time. New QR tags may be required annually after potential to emit is calculated by the requirements of 20.2.50.25. Also as more characters are added to a QR code, the QR becomes more finely pixelated and 'busier', requiring the person attempting to scan to be very close to the QR. Plus QR codes will have to be sized appropriate for the equipment they are to be placed on, in some cases requiring very small tags that will be difficult to scan.

It is possible to encode each QR to remotely access a database via the internet instead of displaying the required five data fields, but each tag still must be custom printed to specifically access the data for the unit's EMITT. Additionally, in order to access a database, an operator must allow remote access to their computer networks by unknown users with no user ID, password, or assurances of network security. The security risks to an operator's computer networks are impossible to anticipate.

Use of RFID Tags

RFID tags use a radio frequency to transmit data. RFID requires a specialized reader and cannot be scanned by a smartphone. There is a wide range of RFID tags including passive and active tags and a range of operational radio frequencies. RFID can be favorable over QR codes since it does not rely on a camera or other optical reader to scan, it stores a large amount of data, and a tag can be placed in a concealed location to avoid excessive weathering. But RFID are considerably more expensive than QR, and the cost of an RFID tag can escalate rapidly depending on the parameters of the tag itself. For example, most RFID tags are intended to be read from zero to 10 cm. These RFID tags are inexpensive at around $1.00 each. For distances greater than 10 cm to 1 meter, the cost of the tag increases as does the physical size of the tag; in some cases these tags are $5.00 each.

For distances greater than 1 meter, the cost of the tag increases rapidly. In addition to the cost of the RFID tag, RFID readers have variable costs depending on capabilities. Generally these costs range from $100 to $1,500. Finally, not all RFID tags and reader are compatible. A possibility exists that a state inspector may not be able to read an operator's EMITT if RFID is used because their equipment may not operate on the same frequency.

Conclusion

Ultimately, EMITT will not actually limit emissions or stop leaks so it is unclear what purpose EMITT will serve. What is clear is that it will burden operators with staggering personnel and operational costs. Therefore, an alternative to EMITT is needed. As noted above there are far too many issues for this system to be implemented, even with one year to come into compliance. The system as proposed creates safety, computer security, and

privacy issues for operators. It requires a huge number of personnel hours to setup and perform monitoring tasks. Furthermore, there is no guarantee that the EMITT will remain attached to the equipment due to New Mexico's harsh weather.

The reality is that this prescriptive, controlling system is not needed at all and will simply cause confusion and non-compliance among operators. An alternative to EMITT is proposed within 20.2.50 on the Redline. The proposed alternative would require operators to create a database of all equipment with a potential to emit which would include manufacture model and serial numbers. In the recordkeeping requirements of 20.2.50.12.D.1, these data are to be maintained by the operator in such a way that they can be submitted electronically upon request from the agency. With a properly maintained database requested from an operator, an inspector can arrive at an operator's wellhead site and have the same information (and more) on hand that an EMITT scan would give them.

Standards for Evaporation Ponds (20.2.50.26 NMAC)

As stated above, this proposed section causes a great deal of concern among industry participants.

20.2.50.26.A.1, Applicability, lacks sufficient specificity and clarity. Operators cannot confidently discern which facilities the code intends to include. Operators will presume the rule is written to include all forms of *Pits* (19.15.17 NMAC), *Evaporation, Storage, Treatment and Skimmer Ponds* (19.15.36.17 NMAC) and some believe it intends to supersede regulations recently enacted to encourage produced water re-use and recycling by ignoring provisions for "Recycling facilities", "Recycling containment" and "Treatment" (19.15.34 NMAC). This is especially troublesome and might shut down substantial production in Lea and Eddy Counties. Moreover developing, permitting (where required), and construction of replacement infrastructure suitable to NMED may take years depending on specifics.
There is also concern as to the effective date provided under 20.2.50.26.A.2. We feel it is inappropriate to discuss a timeline for implementation [e.g. 180 days] until the scope of required modifications is clearly defined and understood.

PBPA acknowledges the need, and the importance of engagement, to facilitate the rational minimization of VOC and methane emissions from oil and gas facilities that include for various operational reasons fluid containment systems which are functionally open to the air. Some PBPA members have publicly committed to reduce VOC and methane emissions, even in the absence of applicable code. We expect and trust that rules will be promulgated based

on function, best practices, solid engineering and also acknowledge the importance of safety and mitigating unintended consequences. This will not be accomplished acting in a vacuum.

Many PBPA members recognize the importance of the 2019 New Mexico State Review Report by STRONGER which identifies and details the need for collaboration between NMED-AQB and EMNRD OCD and we respectfully encourage such collaboration.

> https://www.strongerinc.org/wp-content/uploads/2019/10/2019-New-Mexico-State-Review-Report-NMED-EMNRD.pdf

Using OCD codes and definitions in NMAC, many of which have been clarified by administrative procedures and in some cases even courts, is in the best interest of both the State and industry participants.
Practically, it is reasonable to expect that Emissions Standards from open "ponds" or "recycling containments" will vary with equipment types and the purpose. For illustration consider produced water recycling containment. The utility of the proposed tank equipment is a function of both fluid composition itself and the comprehensive design of fluid treatment process including both mechanical and chemical treatment schemes. Systems to remove hydrocarbons from water need to be understood wholistically. In some circumstances a tank with VOC recovery might be a helpful addition while in other situations, it might actually make things worse in terms of avoided emissions.

Specifically, for some qualities of produced water treated for recycle, applications of flotation chemistries breaking emulsions have proved highly effective. In such systems, it is especially important to encourage large scale chemical equilibration of produced water effectively "holding" water 24-48 hours before treatment in large open "ponds" (already benefiting from mechanical separation). Active hydrocarbon skimming is part of the process. Critically, after the comprehensive treatment the resulting produced water is "clean" and literally millions of barrels of produced water stored in recycling containment do not emit significant measurable VOC's.

Most produced water treatment facilities include large surface area, open-air water storage "recycling containment" for both treatment and short-term storage. Evaporation is an uncontrollable consequence of other essential design choices including aeration and ultra-violet light (sunlight) requirements to minimize bacterial growth, water stratification, and especially in some cases to prevent the development of anerobic layers which have the potential to lead to H2S.

Over the years across the Permian Basin, several operators experimented with systems to cover large fresh water and large treated produced water containment facilities motivated mostly to minimize evaporation loses. It is generally acknowledged that all of these efforts proved operational failures in spite of some contrary claims by vendors. Bacteria counts increased many orders of magnitude and large amounts of biocides were administered but failed to control the situation especially with "on-the-fly" applications from the "ponds" to the frack site.

In several cases operators shared "confidentially between themselves" that reservoirs soured more rapidly than expected after these impaired waters were used in fracking. Remediation costs greatly exceeded the value of controlling any evaporated water.

Today it is rare to see covers on any water treatment ponds, and aeration is almost universal. More to the point, VOC emissions above treated containment tend to be minimal, and any covers would still require a completely different engineered system to collect gases, and it is difficult to imagine how that would work at large scale.

The U.S. Environmental Protection Agency ("EPA") has written OOOO and OOOOa emissions rules pertaining to produced water treatment as part of water recycling efforts. At the time of rule-making (5-6 years ago) only Texas had several years of experience with produced water recycling, and EPA Office of Air engaged seriously with officials and staff from regulatory agencies in Texas, as well as with industry scientists to understand the potential emissions from several produced water treatment processing designs. Advanced computations show that emissions of VOCs are expected to be almost non-existent from produced water storage ponds, even when the produced water was high in TDS. This is especially true when the treatment involves certain strong oxidizers that effectively break hydrocarbon emulsions (e.g. chlorine dioxide). Operators are highly motivated to collect the floating hydrocarbons for profit during early produced water treatment phases. As a consequence, EPA Office of Air wrote regulatory language that largely minimizes specific controls on VOCs at produced water treatment facilities for recycle.

Certainly, there has been some evolution in produced water treatment techniques in general. The quality of produced water from the reservoir is the main criteria driving any treatment system design and there is a broad range of produced water quality even in New Mexico depending on geography and reservoir. Especially in the Delaware basin some reservoirs generate produced water of relatively high quality, with TDS approximating sea water, and for various chemical reasons the water retains very little hydrocarbon content in emulsion after mechanical separation. This type of water requires

minimal treatment apart from aerobic aeration before being recycled for fracking.

Credible Information (20.2.50.27 NMAC)

The proposed language in 20.2.50.27 would allow "credible information" obtained by the NMED, or provided by the public, to establish a presumption of noncompliance unless and until the owner or operator provides credible evidence or information demonstrating otherwise. Essentially, guilt is presumed with no rules of the road or standards for evidence. We recommend this provision be removed. If this provision is not removed, modifications to the language are necessary. As currently written, 20.2.50.27 opens the door to accepting random information with, quite possibly, zero accountability on the person submitting the data for the quality, accuracy, and truthfulness of the information. Then, to make matters worse, regardless of who obtains the data (public, the NMED), and based solely on un-reviewed or verified data, an unsuspecting operator is presumed in violation until made aware of the information potentially days, weeks, months or years later. Only when the operator is provided the information is there an opportunity to refute the presumption of noncompliance. Citizen generated compliance information is nothing new but it, like the same information developed by the NMED, must be valid. Enforcement must be based on information that is obtained via defined methods of detection and reporting, scientifically accurate and legally defensible.

As currently written, there is no burden of proof for accusers (NMED, general public). There must be minimum criteria to make an allegation. The NMED also must consider protections for operators from spurious or repetitious claims that are proven false. Members of the public could intentionally waste NMED and operator resources by repeatedly making allegations, as there is such a low threshold as currently written, with no recourse. Nor is there a definition of "credible information" or "credible evidence."

Many technologies currently available to the general public require expertise to utilize, and have significant limitations in terms of developing evidence. While many can detect emissions (or water vapor), quantification is generally quite poor, and without an understanding of the nature of the emission source (permitted, abnormal, upset) it is impossible, without further investigation (presumably the role of the agency), to determine if something is a violation. A recently published paper by Colorado State University indicates that even experienced optical gas imaging inspectors do not become highly proficient until they have conducted hundreds of inspections. The oil and gas industry has invested heavily in detection equipment, training and even in research and development. But all of the tools have limitations and varying appropriate uses. In addition to training and in-field experience to understanding

background, what type of equipment, and process conditions, several instruments require calibration and maintenance practices. Under the language as written, it does not require these practices be followed by those submitting allegations. Nor is there any form of chain of custody. For example, if somebody saw an OGI video of a well-site with emissions posted on YouTube, could they submit it to the agency, and then the agency would automatically deem it credible evidence and a violation? Could said YouTube video be brought forward months or years after being posted on the website?

Has NMED considered the unintended consequences of essentially encouraging those who are opposed to oil and gas development to trespass to obtain evidence? Inspectors, pumpers and those authorized to be on site receive training, have personal protective equipment and monitors to ensure safety on site. Operators are trained on intrinsically safe devices, where to go in case of emergency, how to determine abnormal operating conditions and on tripping and similar hazards. NMED is encouraging members of the public to enter areas where they could intentionally or unintentionally cause significant risk to themselves or others.

NMED has a regulation which outlines enforcement standards (20.2.72.218 NMAC). The proposed rule does not align with the technical and procedural boundaries required by 20.2.72.218 NMAC. Other states have developed criteria for how evidence is collected by NMED and the general public.

On behalf of our members, we respectfully submit these comments, inclusive of the attached recommendations in redlined format, to the NMED and EMNRD, and request they be taken into consideration in the further development of the draft rules. The PBPA appreciates your time in reviewing and considering these comments.

Regards,

Ben Shepperd
President
Permian Basin Petroleum Association

Rule Preamble: The New Mexico Environment Department has developed the following draft regulation pursuant to the directives of Section 74-2-5.3 of the New Mexico Air Quality Control Act. The objective of the proposed rule is to establish emissions standards for volatile organic compounds (VOC) and nitrogen oxides (NOx) for oil and gas production and processing sources located in areas of the State within the Environmental Improvement Board's jurisdiction where ozone concentrations are exceeding 95% of the national ambient air quality standard.

This is a preliminary draft being released for public input in advance of the Department filing a formal rulemaking petition with the Board and requesting a public hearing. The purpose of this initial, pre-petition comment period is to foster transparency and facilitate continued engagement from stakeholders, members of the public, and other interested parties. Specifically, the Department is seeking public input on the proposed rule language to assist in identifying potential regulatory and technical issues, and areas that require additional clarification or modification. Additional opportunities for public input and changes to the draft rule will occur through the formal rule-making process following the filing of the rulemaking petition. This initial, pre-petition process will help ensure that major issues or problematic areas are identified and can be addressed prior to the initiation of the formal process.

NMED is soliciting specific review and public input on a number of proposed provisions and concepts in the draft rule. In particular, for the equipment standards section, NMED requests feedback on the following:

1. The proposed definitions of stripper wells and marginal wells under the draft rule and the regulatory requirements that would apply to those wells under Section 20.2.50.25 NMAC;
2. Examples of technologies or regulatory programs utilizing non-combustion emission control technologies, like fuel cells, as a means of reducing or eliminating emissions for inclusion in Section 20.2.50.15 NMAC;
3. Specific regulatory language regarding criteria necessary to demonstrate equivalency of alternative equipment leak monitoring plans in Section 20.2.50.16(C) NMAC;
4. Specific regulatory language to establish a pre-approved equipment leak monitoring plan in 20.2.50.16(C) NMAC;
5. For leak detection and repair requirements under Section 20.2.50.16 NMAC, specific standards to be used by NMED to determine if certain new or existing technologies (real-time remote fence line and aerial surveillance, for example) or proposals are enforceable, effective, and equivalent. Specific feedback on data capture requirements, quality assurance, error rates, calibration requirements, training and certification, interference issues, quantification methods, and pollutant identification will assist the Department in exploring this option further;
6. Regulatory requirements for oil and gas evaporative ponds in Section 20.2.50.26 NMAC, including whether to establish emission standards based on the pond's potential to emit or throughput; and
7. Opportunities for greater transparency.

Comments or input on the draft rules may be submitted electronically to nm.methanestrategy@state.nm.us or via hardcopy to Liz Bisbey-Kuehn, NMED Air Quality Bureau, 525 Camino de los Marquez, Santa Fe, NM 87505 by 5 p.m. Aug. 20, 2020.

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND NATURAL GAS REGULATION FOR OZONE PRECURSORS

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TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND NATURAL GAS REGULATION FOR OZONE PRECURSORS

20.2.50.1 ISSUING AGENCY:
New Mexico Environmental Improvement Board.

20.2.50.2 SCOPE:
This rule applies to sources located within counties that have areas with ambient ozone concentrations in excess of ninety-five percent of the national ambient air quality standard for ozone, including but not limited to Chaves, Eddy, Lea, Rio Arriba, Sandoval, and San Juan. Sources located in Bernalillo County, on Tribal Lands, and in other areas that are not within the Board's jurisdiction are excluded. This rule is intended to supplement Title 20.

Commented [SR1]: Will there be an exit ramp for these counties once the ambient ozone concentrations decrease?

20.2.50.3 STATUTORY AUTHORITY: NMSA 1978, § 74-2-5.3

20.2.50.4 DURATION: Permanent.

20.2.50.5 EFFECTIVE DATE:
[To be determined], except where a later date is cited in a section or paragraph.

Commented [SR2]: We recommend delaying the effective date or creating a tiered effective date for the most burdensome requirements in the draft rule. This will help vendors have sufficient equipment in place.

20.2.50.6 APPLICABILITY:

A. Except as provided in paragraph (B), Part 50 applies to crude oil production and natural gas production equipment and operations that extract, collect, store, transport, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other form of transportation. Natural gas production, processing, transmission, and storage includes the well and extends to, but does not include, the local distribution company custody transfer station.

B. Oil refineries are not subject to this Part. Gas processing plant owners and operators are not subject to this part if in compliance with the requirements of Title V, KKK, OOOO, OOOOa, VV, VVa and HH.

C. Equipment located at stripper well facilities, as defined in 20.2.50.8 NMAC, are only required to comply with provisions specified in 20.2.50.25 NMAC.

D. Individual facilities with a site-wide total annual potential to emit less than 25 tons per year (tpy) of volatile organic compounds (VOC) are exempt from the requirements of this Part, except as specified in 20.2.50.25 NMAC. Shut-in wells, as defined in 20.2.50.8 NMAC, are exempt from the requirements of this Part 50, provided:
   (a) Prior to shut in tanks are consolidated, emptied, and system degassed to the extent practicable to minimize emissions during shut-in time;
   (b) Upon bringing Wellhead site back online, monitoring and testing requirements under this Part will resume; and
   (c) Time of which the well is Shut-in will be documented.

~~Individual facilities with a site-wide total annual potential to emit less than 15 tons per year (tpy) of volatile organic compounds (VOC) are exempt from the requirements of this Part, except as specified in 20.2.50.25 NMAC.~~

20.2.50.7 OBJECTIVE:

The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and nitrogen oxides (NO_x) for oil and gas production and processing sources.

20.2.50.8 DEFINITIONS:

In addition to the terms defined in 20.2.2 NMAC (Definitions), as used in this Part:

A. "Air Pollution Control Equipment" means open flares, enclosed combustion devices, thermal oxidizers, ~~vapor recovery units,~~ fuel cells, condensers, other combustion devices, air fuel ratio controllers, oxidative catalytic converters, selective and non-selective catalytic converters, or emission reduction equipment or technologies used to comply with emission standards and emission reduction requirements in 20.2.50 NMAC that are approved by the Department.

B. "Approved Instrument Monitoring Method" means an optical gas imaging thermal camera ~~infra-red camera~~, U.S. EPA Method 21, or other instrument-based monitoring method or program approved by the Department in advance and in accordance with 20.2.50 NMAC.

C. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

D. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas and VOC is continuously or intermittently vented (bleeds) from a pneumatic controller.

~~**E.** "Calendar Year" means a year beginning January 1 and ending December 31.~~

E. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

~~**G.** "Commencement of operation" means for oil and natural gas wellheads, the date any permanent production equipment is in use and product is flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than the end of well completion operations.~~

F. "Company Fleet" means the company who operators the engines. When an engine is rented or leased from a company owner, company fleet refers to the company defined as the operator in a contract rental or lease agreement.

G. "Compressor station" means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.

H. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

I. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.

J. "Credible Information" means information of the type that would qualify as admissible evidence in proceeding before a New Mexico Court, and that is validated by the submitter against requirements contained in either this Part or applicable permits, rules or orders issued by the Department; *provided that* the submitter must calculate alleged

emissions estimates and make a threshold showing of the alleged violation, and the Department, in its discretion, must then independently find the submitted information to be credible.

K. "Custody Transfer" means the transfer of oil or natural gas after processing and/or treatment in the producing operations or from storage tanks ~~vessels~~ or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

L. "Department" means the New Mexico Environment Department.

M. "Downtime" means any ~~the~~ period of time when air pollution control equipment is not operational and an associated well is producing. ~~or a well is producing and the air pollution control equipment is not in operation.~~

N. "Enclosed Combustion Device" means any combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to enclosed flares, boilers, re-boilers, and heaters.

O. "Evaporative Pond" shall mean evaporation ponds which are either (i) not permitted by the New Mexico Oil Conservation Division, or (ii) ponds which are located within a Surface Waste Management Facility permitted under Part 19.15.36 NMAC. For the purposes of this Part, recycling, storage, treatment and reuse equipment utilized pursuant to NMSA 1978, § 70-13-1, et seq. shall not qualify as an Evaporative Pond.

Commented [SR3]: The purpose of the Produced Water Act was to encourage water recycling and reuse – particularly within the oil field. If below requirements apply to produced water recycling facilities, it will be uneconomic to recycle and reuse produced water within the oil field. This definition is intended to: (1) indicates that certain types of evaporative ponds are subject to regulation; and (2) make clear that, if a pond is used pursuant to the Produced Water Act, it is not subject to these requirements.

P. "Existing" means any piece of equipment regulated by this Part that began operation prior to the effective date of the rule and has not since been modified or reconstructed.

Q. "Gas processing plant" means equipment assembled for the extraction of natural gas liquids from natural gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

R. "Gathering and boosting site" means any permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water downstream of ~~between~~ the wellhead site. ~~and~~ Midstream oil and natural gas collection or distribution facilities including ~~such as~~ tank batteries or compressor stations, or sites into or out of storage.

S. "Glycol Dehydrator" means any device in which a liquid glycol absorbent (including, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream and absorbs water.

T. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, ~~produced water,~~ and intermediate hydrocarbons.

~~"Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.~~

U. "Liquids Unloading" means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production.

V. "Liquid Transfers" means the loading and unloading of hydrocarbon liquids ~~or produced water~~ between storage tanks and tanker trucks or tanker rail cars for transport. Transfers of produced water that has been processed through wellhead sites separation equipment and placed into a storage tank for disposal shall not be subject to this definition.

W. "Modification" means any physical change in, or change in the method of operation of,

a stationary source which results in an increase in the potential emission rate of any regulated air contaminant emitted by the source or which results in the emission of any regulated air contaminant not previously emitted, but does not include:

(1) a change in ownership of the source;

(2) routine maintenance, repair or replacement;

(3) installation of air pollution control equipment, and all related process equipment and materials necessary for its operation, undertaken for the purpose of complying with regulations adopted by the board or pursuant to the federal act; or

(4) unless previously limited by enforceable permit conditions:

(a) an increase in the production rate, if such increase does not exceed the operating design capacity of the source;

(b) an increase in the hours of operation; or

(c) use of an alternative fuel or raw material if, prior to January 6, l975, the source was capable of accommodating such fuel or raw material, or if use of an alternate fuel or raw material is caused by any natural gas curtailment or emergency allocation or any other lack of supply of natural gas.

X. "Natural Gas Compressor Station" means one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

Y. "Natural Gas-Fired Heater" means an enclosed device using controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

Z. "Natural Gas Processing Plant" means any processing equipment engaged in the extraction of natural gas liquids from natural gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

AA. "New" means any piece of equipment regulated by this Part that began operation on or after the effective date.

BB. "Optical gas imaging" means an imaging technology that utilizes high-sensitivity infra-red cameras designed for and capable of detecting hydrocarbons.

CC. "Pneumatic Controller" means an automated instrument used for maintaining a process condition such as liquid level, pressure, flow volume, delta-pressure and temperature.

DD. "Pneumatic Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

EE. "Potential to Emit" means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is legally and practicably ~~federally~~ enforceable. The potential to emit for nitrogen dioxide shall be based on total oxides of nitrogen.

FF. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

GG. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.

HH. "Responsible Official" means one of the following:

(1) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating.

(2) For a partnership or sole proprietorship: a general partner or the proprietor, respectively.

(3) For a municipality, state, federal or other public agency: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of US EPA).

II. "Shut-in" means the status of a production well or an injection well that is temporarily closed, whether by closing a valve or disconnection or other physical means. 19.15.2.7.S(5)

JJ. "Startup" means the setting into operation of any air pollution control equipment or process equipment.

KK. "Storage tank" means any single tank that is designed to contain an accumulation of hydrocarbon liquids or produced water and is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass or plastic). ~~process vessel, or fixed roof storage vessel or series of storage vessels that are connected together via a liquid line.~~

~~**KK.** "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquids or produced water and is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support, or a process vessel such as surge control vessels, bottom receivers, or knockout vessels. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. A storage vessel does not include: vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships); are located at the site for less than 180 consecutive days; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.~~

LL. "Stripper well facilities" means an individual oil or gas well or Wellhead Site, as defined herein, with a daily average oil production not exceeding 15 barrels of oil per day, or a natural gas well with a daily average natural gas production not exceeding 250,000 standard cubic feet per day, or any wellhead site with a site-wide total annual potential to emit less than 25 tons per year (tpy) of volatile organic compounds (VOC). ~~oil well with a maximum daily average oil production not exceeding 10 barrels of oil per day, or a natural gas well with a maximum daily average natural gas production not exceeding 60,000 standard cubic feet per day, or a well with a maximum daily average combined oil and natural gas production not exceeding 10 barrels of oil equivalent per day during any 12-month consecutive time period.~~

MM. "Vapor recovery unit" means a system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tanks. The switch detects pressure variations inside the tanks and turns the compressor on and off. The vapors are sucked through a scrubber, where the liquid trapped is returned to the liquid pipeline system or to the tanks, and the vapor recovered is pumped into gas lines. To determine if a VRU is process or control equipment the operator must answer the following three questions:

(1) Is the primary purpose of the equipment to control air pollution?

(2) Where the equipment is recovering product, how do the cost savings from the product recovery compare to the cost of the equipment?

(3) Would the equipment be installed if no air quality regulations are in place?

If the primary purpose is to control air pollution, then the VRU is Air Pollution Control Equipment.

NN. "Wellhead site" means all equipment ~~at a single stationary source~~ directly associated with one or more oil wells or natural gas wells upstream of the gathering and boosting site(s). ~~natural gas processing plant.~~ This equipment includes, but is not limited to, equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

OO. "Workover" means any operation done on, within, or through the wellbore or downhole after the initial completion of a well.

Commented [SR4]: We are greatly concerned that the language originally provided on this topic contradicts NSPS OOOO/OOOOa. We have attempted to reconcile this concern with the provided language herein, but want to strongly encourage ED to make sure it is not contradicting federal law with its definition of a "vapor recovery unit."

20.2.50.9 AMENDMENT AND SUPERSESSION OF PRIOR REGULATIONS [PLACEHOLDER]

20.2.50.10 DOCUMENTS:

Documents incorporated and cited in this Part may be viewed at the New Mexico Environment Department, Air Quality Bureau, Harold Runnels Building, 1190 St. Francis Dr., or 2048 Galisteo St., Santa Fe, NM 87502 [87505].

20.2.50.11 PLACEHOLDER

20.2.50.12 GENERAL PROVISIONS

A. General Requirements

(1) All equipment subject to requirements under 20.2.50 NMAC shall be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the Department.

(2) Owners and operators of equipment subject to requirements under 20.2.50 NMAC shall establish and implement a plan to minimize emissions during routine or predictable startup, shutdown, and scheduled maintenance through work practice standards and good air pollution control practices. [20.2.7.14 NMAC]

(3) The emission of an air contaminant in excess of the quantity, rate, opacity, or concentration specified in 20.2.50 NMAC that results in an excess emission is a violation of 20.2.50 NMAC.

(4) The owner or operator of equipment having an excess emission shall comply with 20.2.7 NMAC and, to the extent practicable, operate the equipment, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(5) The owner or operator of equipment that has an excess emission may claim an affirmative defense for the excess emission pursuant to 20.2.7.111, 20.2.7.112, and 20.2.7.113 NMAC.

(6) Within one year of the effective date of this rule, owners and operators of equipment subject to the requirements of 20.2.50 NMAC shall inventory all equipment regulated by this rule located at wellhead sites. The owner or operator will use the inventory to create and maintain an EQUIPMENT DATABASE of regulated equipment at each wellhead site. The Equipment Database shall include: coordinates of the wellhead site in Latitude/Longitude, unique unit ID of each regulated equipment, manufacturer, model number, serial number (if present), and date placed in service. The database will also include results of periodic activities and/or repairs required by 20.2.50 NMAC; including name(s) of personnel performing activities or repairs.
~~Within one year of the effective date of this rule, owners and operators of equipment requiring an Equipment Monitoring Information and Tracking Tag (EMITT) shall physically tag the unit with an EMITT that is scannable with a hand held scanner (RFID or QR) that uniquely identifies the unit to which it is assigned and the EMITT shall be maintained by the owner or operator. Data in the EMITT shall be scannable by state inspectors to provide at a minimum, the following information:~~

~~(a) Unique unit identification number;~~
~~(b) UTM coordinates of the facility;~~
~~(c) Type of unit (tank, VRU, dehydrator, pneumatic controller, etc.);~~
~~(d) For equipment, the VOC (and NOx, if applicable) potential to emit in pounds per hour and tons per year; and~~
~~(e) For control equipment, the controlled VOC (and NOx, if applicable) potential to emit in pounds per hour and tons per year and the design control efficiency in percent.~~

(7) The Equipment Database shall be retained electronically by the owner or operator and submitted to state inspectors upon request.
~~The EMITT shall be linked to an EMITT Database accessible to state inspectors that at a minimum supplies the data required by Section 20.2.50.12 NMAC and any other data required for that equipment under this Part.~~

B. Monitoring Requirements

(1) All equipment subject to control or monitoring requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different inspection schedule is specified in the section below applicable to that particular type equipment. If the emission unit is shutdown at the time when periodic monitoring or inspections are due to be accomplished, the owner or operator is not required to restart the unit for the sole purpose of performing the monitoring or inspection but shall so note in the equipment or controller's records.

(2) All periodic monitoring events shall be conducted during normal operating

Commented [SR5]: For small equipment, such as pneumatics, it may be difficult to create a unique I.D. because there may be more than one on a piece of equipment.

conditions. ~~at 90% or greater of the unit's capacity. If the 90% capacity cannot be achieved, the monitoring will be conducted at the maximum achievable load under prevailing operating conditions.~~

(3) In order to allow for equivalent new and alternate monitoring technologies that satisfy the requirements of this regulation, prior to implementing, owners and operators may request an equally effective, enforceable, and equivalent alternative monitoring strategy to the Department for approval.
   (a) Each request shall be made on application forms provided by the Department. Upon approval of a request, the Department will issue an Alternative Monitoring Approval Letter. All Alternative Monitoring Approval Letters will be published on a link on the Department's webpage to provide authorization for the use of the approved alternative monitoring method.
   (b) Each owner or operator will need to request and receive approval from the Department in order to operate under an approved Alternative Monitoring Strategy.

(4) Each monitoring event shall be entered into the owner or operator's equipment database. ~~EMITT shall be initially scanned and the required monitoring data shall be electronically captured during the monitoring event. The captured data shall be uploaded (either live or subsequently) into the database.~~ At a minimum, the database ~~uploaded~~ data shall include:
   (a) Date and time of the monitoring event;
   (b) The name of the monitoring personnel;
   (c) Unique unit identification number;
   (d) Type of unit;
   (e) A description of any maintenance or repair activities conducted; and
   (f) Required results of any monitoring required by 20.2.50 NMAC.

C. Recordkeeping Requirements

(1) Owners and operators shall keep records of any inspections and/or maintenance required under this Part. Records shall include:
   (a) Date and time of the monitoring event;
   (b) The name of the monitoring personnel;
   (c) Unique unit identification number;
   (d) Type of unit;
   (e) Required results of any monitoring required by 20.2.50 NMAC;
   (f) Equipment make, model and serial number;
   (g) A copy of the equipment manufacturer's maintenance or repair recommendations;
   (h) A description of any maintenance or repair activities conducted; and
   (i) All results of any required parameter readings.

(2) Owners and operators shall keep records required this Part for a period of five years. The records shall be retained electronically. The Department may treat any loss of data or failure to maintain records (including failure to transfer records upon sale or transfer or ownership or operating authority) as a failure to collect the data.

(3) Owners and operators shall keep records of emissions from equipment malfunctions and routine or predictable emissions during startup, shutdown, and scheduled maintenance.

(4) Owners and operators of equipment having an excess emission shall record the

following information no later than ten (10) days after the end of the excess emission event:

(a) The equipment type and identification number;
(b) The location, date, and time;
(c) The emission limit or air quality regulation that was exceeded;
(d) The air contaminant and the magnitude of the excess emission expressed in the units of the limit or air quality regulation;
(e) The cause of the excess emission and any steps taken to limit the magnitude and duration of the excess emissions;
(f) The corrective action(s) taken to eliminate the cause of the excess emission and prevent a recurrence, if required; and
(g) Whether the owner or operator attributes the excess emission to malfunction, startup, or shutdown.

(5) Records of each ~~EMITT~~ monitoring event required by 20.2.50.12.B NMAC shall be entered into the equipment ~~electronically uploaded (either in real time or subsequently) into the EMITT~~ database. At a minimum, the database uploaded data shall include the data required in 20.2.50.12.B(4) and 20.2.50.12.C(4) NMAC.

(6) Prior to the transfer of ownership of any equipment subject to this Part, the new ~~current~~ owner or operator shall conduct and document a full compliance evaluation of all equipment subject to the rule. The documentation shall indicate whether or not each piece of equipment subject to requirements under this Part is currently complying with those requirements. The compliance determination shall be conducted no earlier than one year prior to the transfer.

D. Reporting Requirements

(1) Owners and operators shall submit reports upon the request of the Department. Any reports requested by the Department shall be submitted electronically via the Department's Secure Extranet Portal (SEP) at https://sep.net.env.nm.gov/sep/login-form.

(2) Owner and operators of a source having an excess emission shall submit a Root Cause and Corrective Action Analysis, as directed in 20.2.7.114 NMAC, upon the request of the department.

20.2.50.13 STANDARDS FOR ENGINES AND TURBINES

A. Applicability

(1) New and existing portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellheads, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.13 NMAC.

(2) Existing sources that were subject to federal standards of performance under 40 CFR Part 60 and Part 63 between March 25, 2004 and January 1, 2009 are exempt from the requirements of 20.2.50.13 NMAC.

B. Emission Standards

(1) Owners and operators of each portable or stationary natural gas-fired spark

ignition engine, compression ignition engine, and natural gas-fired combustion turbine shall ensure compliance with the emission standards in 20.2.50.13.B NMAC by the dates specified in 20.2.50.13.B NMAC.

(2) Each new natural gas-fired spark ignition engine shall comply with all the applicable New Source Performance Standards (NSPS) subpart JJJJ requirements and shall not exceed NSPS emission standards as applicable to July 1, 2020 and later model year standards of the same size/power. All existing engines shall comply with all applicable NSPS subpart JJJJ requirements not to exceed NSPS emission standards as applicable to July 1, 2007 and later model year engines of the same size/power. ~~emission standards in Table 1 of 20.2.50.13 NMAC.~~

Commented [SR6]: Alternative language: New natural gas-fired spark ignition engines shall comply with all applicable New Source Performance Standards (NSPS) for the engine's model year. Existing natural gas-fired spark ignition engines shall at a minimum comply with the 2007 NSPS for engines of the same size and power. If the existing engine post-dates the 2007 NSPS but pre-dates this rule it shall comply with the NSPS in place at the time the model was produced.

(3) By January 1, 2022, owners and operators of existing engines shall complete an inventory of all existing engines and shall prepare a schedule for each existing engine to ensure that all existing engines comply with these requirements and meet or exceed the emission standards in Table 1 by January 1, 2028. The schedule shall meet the following requirements:

(a) By January 1, 2024, owners and operators shall ensure 30% of the company's fleet of existing engines meet the requirements ~~of Table 1~~.

(b) By January 1, 2026, owners and operators shall ensure an additional 35% of the company's fleet of existing engines meet the requirements ~~of Table 1~~.

(c) By January 1, 2028, owners and operators shall ensure that the remaining 35% of the company's fleet of existing engines meet the requirements ~~of Table 1~~.

~~Table 1 - Emission Standards for Natural Gas-Fired Spark Ignition Engines~~

~~**For each natural gas-fired spark ignition engine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the existing engine(s) does not exceed the following emission standards as determined by the compliance schedule required in 20.2.50.13.B(3) NMAC:**~~

~~Engine Type~~	~~Rated bhp~~	~~NOx~~	~~CO~~	~~NMNEHC (as propane)~~
~~Lean-burn~~	~~≤100~~	~~2.0 g/bhp-h~~	~~2.0 g/bhp-h~~	~~-~~
~~Lean-burn~~	~~>100 - ≤500~~	~~1.0 g/bhp-h~~	~~2.0 g/bhp-h~~	~~0.70 g/bhp-h~~
~~Lean-burn~~	~~>500~~	~~0.50 g/bhp-h~~	~~47 ppmvd @ 15% O2 or 93% reduction~~	~~0.30 g/bhp-h~~
~~Rich-burn~~	~~≤100~~	~~2.0 g/bhp-h~~	~~2.0 g/bhp-h~~	~~-~~
~~Rich-burn~~	~~>100 - ≤500~~	~~0.25 g/bhp-h~~	~~0.30 g/bhp-h~~	~~0.20 g/bhp-h~~
~~Rich-burn~~	~~>500~~	~~0.20 g/bhp-h~~	~~0.30 g/bhp-h~~	~~0.20 g/bhp-h~~

(4) Owners and operators of natural gas-fired spark ignition engines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to 15 percent oxygen.

(5) Owners and operators of each compression ignition engine shall ensure compliance with the applicable emission standards in 20.2.50.13.B(5)(a) NMAC and 20.2.50.13.B(5)(b) NMAC.

(a) Stationary compression ignition engines that are subject to and complying with standards in 40 CFR Part 60, subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, are exempt from the requirements of this paragraph.

(b) Portable and stationary compression ignition engines with a maximum design power output equal to or greater than 500 horsepower that are not subject to the emission standards under 20.2.50.13.B(5)(a) NMAC shall limit NOx emissions to no more than 9 g/bhp-h. For each compression-ignition engine constructed or reconstructed and installed before the effective date of this Part, the owner or operator shall ensure compliance no later than one year from the effective date. For each compression-ignition engine constructed or reconstructed and installed on or after the effective date of this Part, the owner or operator shall ensure compliance upon startup.

(6) Owners and operators of portable or stationary compression ignition engines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15 percent oxygen.

(7) Owners and operators of stationary natural gas-fired combustion turbines with a maximum design rating equal to or greater than 1,000 bhp (or a maximum heat input capacity equal to or greater than 2.54 MMBtu/hr) shall comply with the applicable emission standards for existing, new, or reconstructed turbines listed in Table 1 ~~2~~ of 20.2.50.13 NMAC.

Table 1 ~~2~~ - Emission Standards for Stationary Combustion Turbines

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than one year from the effective date:

Turbine Rating (bhp)	Turbine Rating (MMBtu/hr)	NOx (ppmvd @15% O2)	CO (ppmvd @ 15% O2)	NMNEHC (as propane, ppmvd @15% O2)
≥1,000 and <5,000	≥2.54 and <12.7	25	25	9
≥5,000 and <15,000	≥12.7 and <38.2	15	25	9
≥15,000	≥38.2	15	10 or 93% reduction	5 or 50% reduction

For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:

Turbine Rating (bhp)	Turbine Rating (MMBtu/hr)	NOx (ppmvd @15% O2)	CO (ppmvd @ 15% O2)	NMNEHC (as propane, ppmvd @15% O2)

≥1,000 and <5,000	≥2.54 and <12.7	25	25	9
≥5,000 and <15,900	≥12.7 and <40.4	15	10	9
≥15,900	≥40.4	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) Owners and operators of stationary natural gas-fired combustion turbines that control NOx emissions with a control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to 15% oxygen.

(9) Owners and operators of new or existing engines or turbines shall record each engine or turbine in the equipment database in accordance with 20.2.50.12 NMAC. ~~Owners and operators of new or existing engines or turbines shall install an Equipment Monitoring and Information Tracking Tag (EMITT) on each engine or turbine in accordance with 20.2.50.12 NMAC.~~

C. Monitoring Requirements

(1) Maintenance and repair for all spark ignition engines, compression ignition engines, and stationary combustion turbines shall meet the minimum engine or turbine manufacturer's recommended maintenance schedule. Activities that involve engine or turbine maintenance, adjustment, replacement, or repair of functional components with the potential to affect the operation of an emission unit shall be documented as they occur for the following events:

(a) Routine maintenance that takes a unit out of service for more than two hours during any 24-hour period.

(b) Unscheduled repairs that require a unit to be taken out of service for more than two hours in any 24-hour period.

(2) Oxidation catalytic converters, selective and non-selective catalytic converters, and air-fuel ratio (AFR) controllers shall be maintained according to manufacturer's or supplier's recommended maintenance, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalyst or AFR controller maintenance, the owner or operator shall shut down the engine(s) or turbine(s) until the catalyst or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to remain in operation.

(3) Compliance with the emission standards in 20.2.50.13.B NMAC shall be demonstrated by performing an initial and annual test for NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or EPA Reference Methods. The initial test shall be performed within one year of the effective date of this rule. For units with g/hp-hr emission standards, the engine load shall be calculated by using the following equations:

Commented [SR7]: A one year time frame shows up throughout the rule and should also apply here to engines.

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scfh) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where:
LVH = lower heating value, btu/scf, or btu/gal, as appropriate
BSCF = brake specific fuel consumption

(a) Periodic monitoring utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. However, if a facility has met a previously approved Department criterion for portable analyzers, the analyzer may be operated in accordance with that criterion until it is replaced.
(b) The default time period for each test run shall be at least 20 minutes.
(c) Each performance test shall consist of three separate runs. The arithmetic mean of results of the three runs shall be used to determine compliance with the applicable emission standard.
(d) For all periodic monitoring events, three test runs shall be conducted at 90% or greater of the unit's capacity. If the 90% capacity cannot be achieved, the monitoring will be conducted at the maximum achievable load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions and shall be included with the monitoring test report.
(e) During emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing EPA Reference Method 19. This information shall be included with the monitoring test report.
(f) Stack gas flow rate shall be calculated in accordance with EPA Reference Method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months prior to the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using EPA Reference Methods 1 through 4.
(g) The owner or operator shall submit a notification and protocol for periodic emissions tests upon the request of the Department.

(4) Testing shall be conducted once per calendar year. Performance testing required by 40 CFR 60, Subparts GG, IIII, JJJJ, or KKKK, or 40 CFR 63, Subpart ZZZZ may be used to satisfy these periodic testing requirements if they meet the requirements of this section and are completed once per calendar year.
(5) Each monitoring, testing, inspection, or tune-up of an engine or turbine ~~shall include the initial scanning of the EMITT, and the monitoring data entry~~ shall be recorded in the equipment database ~~made~~ in accordance with the requirements of 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) The owner or operator of spark ignition engines, compression ignition engines, or stationary combustion turbines shall maintain records in accordance with

20.2.50.12 NMAC for each engine or turbine of:

(a) The make, model, serial number, and equipment identification number for each engine, turbine, and any control equipment,
(b) A copy of the engine or turbine manufacturer's or control equipment manufacturer's recommended maintenance and repair schedule,
(c) Inspections, maintenance and repairs activities on all engines, turbines, and control equipment, including:
  (i) Date(s) and time(s) of inspection, maintenance, and/or repair;
  (ii) Date(s) any subsequent analyses were performed (if applicable);
  (iii) Name of the person or qualified entity conducting the inspection, maintenance, and/or repair;
  (iv) A description of the physical condition of the equipment as found during any required inspection;
  (v) Description of maintenance or repair activities conducted; and
  (vi) Results of required equipment inspections including a description of any condition which required adjustment to bring the equipment back into compliance and a description of the required adjustments.
(d) Results of any required parameter readings.

(2) The owner or operator of spark ignition engines, compression ignition engines, or stationary combustion turbines shall maintain records of initial and annual performance testing in accordance with 20.2.50.12 NMAC for each engine or turbine, including:
(a) The make, model, serial number, and equipment identification number for all tested engines, turbines, and emission control equipment);
(b) Date(s) and time(s) of sampling or measurements;
(c) Date(s) analyses were performed;
(d) The qualified entity that performed the analyses;
(e) Analytical or test methods used;
(f) Results of analyses or tests; and
(g) Operating conditions existing at the time of sampling or measurement.

(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.14 STANDARDS FOR COMPRESSOR SEALS

A. Applicability

(1) All new and existing centrifugal compressors using wet seals located at tank batteries, gathering and boosting sites, ~~natural gas processing plants~~, and transmission compressor stations are subject to the requirements of 20.2.50.14 NMAC. Any new or existing centrifugal compressor located at a wellhead is not subject to the requirements of 20.2.50.14 NMAC.

(2) All new and existing reciprocating compressors located at tank batteries,

gathering and boosting sites, ~~natural gas processing plants,~~ and transmission compressor stations are subject to the requirements of 20.2.50.14 NMAC. Any new or existing reciprocating compressor located at a wellhead is not subject to the requirements of 20.2.50.14 NMAC.

B. Emission Standards

(1) Owners and operators of existing centrifugal compressors shall control VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95%, beginning on the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(2) Owners and operators of existing reciprocating compressors shall, either:

(a) Replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours and months of compressor operation toward the first replacement of the rod packing beginning no later than one year from the effective date; OR

(b) Beginning no later than one year from the effective date, collect emissions from the rod packing under negative pressure and route via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(3) Owners and operators of new centrifugal compressors shall control VOC emissions from each centrifugal compressor wet seal fluid degassing system by 98% upon startup. Emissions shall be captured and routed via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

(4) Owners and operators of new reciprocating compressors shall, upon startup, either:

(a) Replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; OR

(b) Collect emissions from the rod packing under negative pressure and route via a closed vent system to a control system, a recovery system, fuel cell, or a process stream.

~~(5) Owners and operators of new and existing centrifugal and reciprocating compressors shall install an Equipment Monitoring Information Tracking Tag (EMITT) on each compressor in accordance with 20.2.50.12 NMAC.~~

(5) Owners and operators complying with the control requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the control device requirements in 20.2.50.15 NMAC.

(6) Owners and operators with an air permit shall incorporate these requirements in their permit during their next scheduled or requested permit or permit revision.

C. Monitoring Requirements

(1) The owner or operator of a centrifugal compressor complying with 20.2.50.14.B(1) NMAC or 20.2.50.14.B(3) NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.15 NMAC.

(2) The owner or operator of a reciprocating compressor complying with

20.2.50.14.B(2)(a) NMAC or 20.2.50.14.B(4)(a) NMAC shall continuously monitor the number of hours of operation with a non-resettable hour meter and track the number of months since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with 20.2.50.14.B(2)(b) NMAC or 20.2.50.14.B(4)(b) NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device.

(4) Owners and operators complying with the requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

(5) Owners and operators of new and existing centrifugal and reciprocating compressors, during each required monitoring activity, shall enter ~~scan the compressor EMITT and perform~~ monitoring data ~~entry~~ in accordance with the requirements of 20.2.50.12 NMAC.

(6) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) The owner or operator of a centrifugal compressor shall maintain records of:

(a) The identification number and location of each centrifugal compressor using a wet seal system,

(b) The date of construction, reconstruction, or modification of each centrifugal compressor,

(c) The records of the monitoring and inspections required in 20.2.50.14.C NMAC. The records shall include the time and date of the inspection, the person conducting the inspection, a notation of which checks required in 20.2.50.12.C NMAC were completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken, and

(d) The location, type, make, model and unique identification number of any control equipment, recovery system, fuel cell, or process used to comply with the control requirements in 20.2.50.14.B NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain records of the following:

(a) The identification number and location of each reciprocating compressor;

(b) The date of construction, reconstruction, or modification of each reciprocating compressor; and

(c) The records of the monitoring and inspections required in 20.2.50.14.C NMAC. The records shall meet the requirements of 20.2.50.14.C NMAC and shall include:

(i) The number of hours of operation and the number of months of operation since initial startup or the last rod packing replacement;

(ii) The records of pressure in the rod packing emissions collection system; and

(iii) The time and date of the inspection, the person conducting the inspection, a notation of which checks required in 20.2.50.14.C NMAC were completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken.

(3) Owners and operators complying with the requirements in 20.2.50.14.B NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(4) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

(1) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.15 STANDARDS FOR CONTROL DEVICES

A. Applicability

(1) These requirements apply to open flares, enclosed combustors, thermal oxidizers, ~~vapor recovery units,~~ condensers, closed vent collection systems, other combustion devices, or emissions reduction equipment or technologies used to comply with the emission standards and emission reduction requirements in this Part.

B. General Requirements

(1) All air pollution control equipment used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications and good engineering and maintenance practices.

(2) All air pollution control equipment shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NOx.

(3) Owners and operators of a flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device used to comply with the emission standards in this Part shall comply ~~install an Equipment Monitoring and Information Tracking Tag (EMITT) on each flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device in accordance~~ with 20.2.50.12 NMAC.

(4) Owners and operators shall inspect all air pollution control equipment used to control emissions from equipment subject to emission standards under this Part at least monthly to ensure proper maintenance and operation. Each ~~EMITT~~ inspection or monitoring event shall be recorded in the equipment database after ~~initially scanned and the required monitoring data shall be electronically captured during~~ the monitoring event.

(5) Owners and operators shall ensure that any flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device used to comply with emission standards in this Part shall at all times operate as a closed vent system that captures and routes all VOC emissions from equipment

subject to regulation under this Part to the control or vapor recovery device and that un-combusted gas is not vented to the atmosphere.

(6) Owners and operators shall keep manufacturer specifications for all control or vapor recovery equipment on file. The information shall include:
   (a) Manufacturer's name, control device name and model;
   (b) Maximum heating value for open flares, enclosed combustors, and thermal oxidizers;
   (c) Fuel gas flow range for open flares, enclosed combustors, and thermal oxidizers; and
   (d) Designed destruction or vapor recovery efficiency.

(7) Owners and operators shall keep records of any stack testing or control or vapor recovery efficiency testing for all control equipment. The records shall be kept in accordance with 20.2.50.12 NMAC for each flare, combustion device, vapor recovery equipment, or other emission reduction technology or control device and shall include:
   (a) Control device type, name and model;
   (b) Location;
   (c) Date of the stack test; and
   (d) A summary of the stack test results.

C. Requirements for Open Flares

(1) Emission Standards
   (a) The flare shall combust all gas sent to the flare. Owners and operators shall not send gas to the flare in excess of the flare's maximum rated capacity.
   (b) Owners and operators shall equip all flares with a continuous pilot flame, an auto-igniter, or require manual ignition.
      (i) Flares with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times that gas is being sent to the flare.
      (ii) Owners and operators of flares with manual ignition shall inspect and ensure a flame is present upon initiating each flaring event.
      (iii) Any new flare constructed or re-constructed after the effective date of this Part shall be equipped with an auto-igniter or continuous pilot. The auto-igniter or continuous pilot shall be installed and operational upon startup.
      (iv) Any existing flare constructed prior to the effective date of this Part shall be equipped with an auto-igniter or continuous pilot no later than one year after the effective date**.**
   (c) Owners and operators shall operate any flare used for controlling VOC emissions to comply with this Part with no visible emissions, except for periods not to exceed a total of sixty (60) seconds during any fifteen (15) consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare, or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring Requirements

(a) Owners and operators of flares with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. Owners and operators may use any other equivalent device that fulfills the same purpose.

(b) Owners and operators of manually ignited flares shall monitor the presence of a flame using continual visual observation during each flaring event.

~~(c) Owners and operators, at least quarterly, and upon observing any visible emissions, shall perform a U.S. EPA Method 22 observation while the flare pilot flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of fifteen (15) consecutive minutes.~~

(c) Each ~~EMITT~~ inspection or monitoring event shall be recorded in the equipment database ~~initially scanned and the required monitoring data shall be electronically captured during the monitoring event~~ in accordance with the monitoring requirements of 20.2.50.12 NMAC.

(3) Recordkeeping Requirements

(a) The owner or operator of open flares subject to regulation under 20.2.50.15.A NMAC shall keep records for each flare in accordance with 20.2.50.12 NMAC of the following:

(i) All instances of alarm activation, including the date and cause of alarm activation, actions taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(ii) The results of ~~the U.S. EPA Method 22~~ observations and flame inspection for manual flares and

(iii) The results of any gas analysis for the gas being flared, including VOC content and heating value.

(4) Reporting Requirements

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

D. Requirements for Enclosed Combustion Devices (ECD) and Thermal Oxidizers (TO)

(1) Emission Standards

(a) The ECD/TO shall combust all gas sent to the ECD/TO. Owners and operators shall not send gas to the ECD/TO in excess of the ECD/TO's maximum rated capacity.

(b) Owners and operators shall equip all ECDs/TOs with a continuous pilot flame or an operational auto-igniter. ECDs/TOs constructed or re-constructed prior to the effective date of this Part shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. ECDs/TOs constructed or re-constructed on or after the effective date shall be equipped with a continuous pilot flame or an operational auto-igniter upon startup.

(c) ECDs/TOs with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at

all times that gas is being sent the ECD/TO. Combustion shall be maintained for the duration of time that gas is being sent to the ECD/TO.

(d) Owners and operators shall operate ECDs/TOs used to control VOC emissions to comply with the emission standards in this Part with no visible emissions, except for periods not to exceed a total of sixty (60) seconds during any fifteen (15) consecutive minutes. The combustion device shall be designed so that an observer can, by means of visual observation from the outside of the combustion device, or by other means, such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring Requirements

(a) Owners and operators of ECDs/TOs with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. Owners and operators may use any other equivalent device that fulfills the same purpose.

~~(b) Owners and operators, at least quarterly, and upon observing any visible emissions, shall perform a Method 22 observation while the ECD/TO pilot flame is present to certify compliance with the visible emission requirements. The observation shall be a minimum of fifteen minutes.~~

(b) Each ~~EMITT~~ inspection or monitoring event shall be recorded in the equipment database ~~initially scanned and the required monitoring data shall be electronically captured during the monitoring~~ event in accordance with the monitoring requirements of 20.2.50.12 NMAC.

(3) Recordkeeping Requirements

(a) The owner or operator of an ECD/TO subject to regulation under 20.2.50.15.A NMAC shall keep records in accordance with 20.2.50.12 NMAC for each ECD/TO of:

(i) All instances of alarm activation, including the date and cause of alarm activation, actions taken to bring the ECD/TO into normal operating conditions, the name of the personnel conducting the inspection, and any maintenance activities performed;

(ii) The results of the Method 22 observations; and

(iii) The results of any gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting Requirements

(a) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

E. Requirements for Control Vapor Recovery Units (VRU)

(1) Emission Standards

(a) Owners and operators shall operate the VRU as a closed vent system that captures and routes all VOC emissions from units back to the process stream or to a sales pipeline and does not vent to the atmosphere.

(b) Owners and operators shall control emissions during startup, shutdown, and maintenance (SSM) or other VRU downtime with a backup control device (flare/ECD/TO) or redundant VRU.

Commented [SR8]: It is recommended that VRUs not be subject to part 20.2.50.15. A VRU is a process device under OOOOa. However, if VRUs are included, recommended changes to 20.2.50.15.E have been provided.

(2) Monitoring Requirements

(a) Owners and operators shall comply with the standards for equipment leaks in 20.2.50.16 NMAC, or, alternatively, shall implement a program that meets the requirements of NSPS Subpart OOOOa (40 CFR 60.5416a).

(b) Each VRU ~~EMITT~~ inspection or monitoring event shall be recorded in the equipment database in accordance with ~~initially scanned and the required monitoring data shall be electronically captured during~~ the monitoring event requirements of 20.2.50.12 NMAC.

(3) Recordkeeping Requirements

(a) For each VRU inspection or monitoring event, the owner or operator shall record the results of the VRU inspections in accordance with 20.2.50.12 NMAC, including the name of the personnel conducting the inspection, and noting any maintenance or repairs that are required.

(4) Reporting Requirements

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.16 STANDARDS FOR EQUIPMENT LEAKS

A. Applicability

All new and existing wellheads, tank batteries, gathering and boosting sites, ~~gas processing plants,~~ transmission compressor stations and associated piping are subject to the requirements of 20.2.50.16 NMAC. Wellhead sites subject to the requirements of 20.2.50.25 NMAC are exempt from this section.

B. Emission Standards

Each owner and operator of oil and gas production and processing equipment located at a site identified in 20.2.50.16.A NMAC shall demonstrate compliance with 20.2.50.16 NMAC by performing the monitoring, recordkeeping, and reporting requirements specified in this Section.

C. Monitoring Requirements

(1) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

(2) Default Equipment Leak Monitoring Requirements:

(a) Owners or operators shall conduct an audible, visual, and olfactory (AVO) inspection of each thief hatch, closed vent system, pump, compressor, pressure relief device, open-ended valve or line, valve, flange, connector, piping, and any associated equipment to identify defects and leaking components at least quarterly (spaced evenly between other leak checks) ~~weekly~~ as follows:

(i) Visually inspect for cracks, holes or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure devices;

(ii) Listen for pressure leaks or liquid leaks.

(iii) Smell for unusual or strong odors.

Commented [SR9]: The section applies to wellhead site equipment where leaks are most frequent, but also adds all oil and gas well heads. The prescribed requirement to check all well heads is in contrast to NSPS OOOOa that require leak checks at well heads ONLY when the well head is located on a wellhead site.
For oil wells: Checking for leaks at a well head is impractical since most wells are not located at the wellhead site, vastly increasing the personnel time required to check for leaks. Additionally, when leaks occur at an oil well, it is readily apparent since fluids are often leaked at the same time.
For gas wells: Gas wells are usually located at the wellhead site, so it is practical to check the well for leaks, although leaks from gas well heads are rare.

Commented [SR10]: Weekly inspections for leaks detectable by audio, visual, and olfactory (AVO) sensing and logging the results using Equipment Database are prescribed in the proposed rule. It is notable that locating leaks by AVO is both dangerous and ineffective. It is dangerous due to the potential presence of H2S gas at sour facilities or being closer than usual to moving machinery. AVO is ineffective since it locates only the highest, most apparent leaks from equipment. It does not locate slow or low volume leaks. Despite that is it not very effective, AVO is part of most operator's standard operating procedure for all field personnel: If unusual conditions are noted by sight, smell, our sounds, field personnel are to determine the source and work to stop it.
An operator's personnel do not visit a given facility on the same day every week and those personnel may not be equipped to perform the prescribed AVO. Prescribing a weekly schedule of AVO inspections when other wellhead sites may need the field personnel to be present could cause spills or fires. Further, if these inspections were required using EMITT, as we previously required, the inspections would slow down field personnel whose job it is to maintain production equipment. The use of EMITT is likely to require 5 minutes per tagged piece of equipment causing the required weekly AVO checks to use an excessive amount of personnel time. If these personnel (lease operators) are spending 1 to 8+ hours performing weekly AVO inspections, they cannot perform their other job functions. It is the standard operating procedure for an operator's field personnel to pay attention for any unusual AVO occurrences and determine the source. Operators already perform AVO.

(iv) Any positive audible, visual, or odorous indication shall be investigated. ~~considered a leak.~~ All confirmed AVO leaks shall be ~~tagged with a visible tag and~~ reported to management or designee within three working ~~calendar~~ days.

(b) Owners or operators shall conduct an inspection using EPA Reference Method 21 (40 CFR 60, Appendix B) (RM 21) or optical gas imaging (OGI) with thermal ~~infrared~~ cameras at wellhead sites of each thief hatch, closed vent system, pump, compressor, pressure relief device, open-ended valve or line, valve, flange, connector, piping, and any associated equipment to identify leaking components semi-annually at all facilities. ~~at a frequency determined according to the following schedule: (i) For well production and tank battery facilities:~~

~~(A) Annually at facilities with a potential to emit less than 2 tpy VOC.~~

~~(B) Semi-annually at facilities with a potential to emit equal to or greater than 2 tpy and less than 5 tpy VOC.~~

~~(C) Quarterly at facilities with a potential to emit equal to or greater than 5 tpy VOC.~~

~~(ii) For gathering and boosting sites, gas processing plants, and transmission compressor stations:~~

~~(A) Quarterly at facilities with a potential to emit less than 25 tpy VOC.~~

~~(B) Monthly at facilities with a potential to emit equal to or greater than 25 tpy VOC.~~

(c) The inspections required under 20.2.50.16.C(2)(b) NMAC shall be conducted using RM 21 or OGI with infrared cameras.

(i) For leaks determined using RM 21:

(A) The instrument shall be calibrated before each day of its use by the procedures specified in RM 21.

(B) The instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air); and a mixture of methane or n-hexane and air at a concentration of about, but less than, 10,000 ppm methane or n-hexane.

(C) A leak is detected if an instrument reading of 500 ppm or greater of hydrocarbon is measured that is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(ii) For leaks determined using OGI:

(A) The instrument must comply with the specifications, the daily instrument checks, and the leak survey requirements in NSPS Subpart OOOOa, at 40 CFR 60.18(i)(1) through (3).

(B) A leak is detected if any hydrocarbon emissions are imaged by the OGI instrument that are not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(d) If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to inspect the component until it becomes feasible to do so.

(i) Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters

Commented [SR11]: Leak detection and repair (LDAR) is an effective mean to locate and repair equipment leaks. Leak detection is required at batteries hydraulically fractured after September 2015 by New Source Performance Standard (NSPS) Subpart OOOOa (Quad Oa). Leak detection is also required by the Bureau of Land Management's (BLM) Venting and Flaring rule. Of the two methods specified by this section, Method 21 uses specialized hand-held gas detection equipment that must be placed very close to the unit being tested and requires a few seconds to get a reading. While Method 21 leak detection is used in gas plants, it is used to detect leaks from valves, flanges, clamps, and open ended pipes. Method 21 is usually not used on large equipment or equipment with a large potential leak area such as a thief hatch. Leak detection with Method 21 slow, requiring a similar amount as time as the EMITT system previously proposed in 20.2.50.12. Optic Gas Imaging (OGI) using a specialized thermal camera is far more common. OGI is fast and effective, allowing an operator to survey large batteries an hour or less. Both leak detection methods are allowed under Quad Oa and Bureau of Land Management (BLM) Venting and Flaring Rule.
20.2.50.16.C(2)(b) prescribes LDAR at wellhead sites on a frequency based on the potential to emit of the wellhead site. The prescribed frequency directly conflicts with stripper wells as defined in 20.2.250.8.LL and the requirements of 20.2.50.25. The specified frequency also conflicts with the schedules of Quad Oa and the BLM Venting and Flaring Rule. Both of the federal rules require semi-annual LDAR, and Quad Oa has an exclusion for low production wellhead sites under 15 barrels of oil equivalent (BOE) per day. Finally, the specified LDAR frequency of 20.2.50.16.C(2)(b) is unusually prescriptive where is it is based on the facilities potential to emit and the most frequent category are quarterly LDAR at wellhead site over 5 tons per year emissions. Few facilities have less than 5 tons per year emissions. In contrast, Colorado Regulation 7 requires quarterly LDAR at facilities over 12 tons per year emissions.
In 20.2.50.16.C(2)(c)ii, leaks that are located with an OGI camera are to be repaired within seven days and verified with within and additional 8 days—15 days total. This conflicts directly with the BLM, and Quad Oa require leaks to be repaired within 30 days and verified with an additional 30 days.
In order for all rules requiring LDAR to be most effective, least costly, and ensure compliance: All LDAR rules need to integrate with each other in order to prevent compliance confusion and to minimize costs to operators.

Commented [SR12]: OGI cameras pick up more than hydrocarbon vapor. Being a thermal camera, it will sense heat. It will also see water vapor depending on temperature differences.

above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

(ii) Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

(iii) Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

(3) Alternative Equipment Leak Monitoring Plans

(a) As an equivalent means of compliance with 20.2.50.16 NMAC, owners or operators may comply with the equipment leak requirements through an individual alternative monitoring plan approved by the Department, subject to the following requirements:

(i) Upon the Department's approval of an alternative monitoring plan, the owner or operator shall comply with the terms and conditions of the approved alternative monitoring plan.

(ii) A responsible official shall certify compliance with the approved alternative monitoring plan on behalf of the owner or operator on an annual basis.

(iii) The Department may terminate an approved alternative monitoring plan if the Department finds that the owner or operator failed to comply with any provision of the plan and failed to correct and disclose the violation(s) to the Department within 15 calendar days of identifying the violation.

(iv) Upon the Department's denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under 20.2.50.16.C(2) NMAC within 30 days.

(b) As an equivalent means of compliance with 20.2.50.16 NMAC, owners or operators may comply with equipment leak requirements through one of the pre-approved monitoring plans maintained by the Department, subject to the following requirements:

(i) The owner or operator shall notify the Department of the pre-approved monitoring plan that the owner or operator will follow and shall comply with the terms and conditions of the pre-approved monitoring plan.

(ii) A responsible official shall certify compliance with the pre-approved monitoring plan on behalf of the owner or operator on an annual basis.

(iii) The Department may terminate the use of a pre-approved monitoring plan by the owner or operator if the Department finds that the owner or operator failed to comply with any provision of the plan and failed to correct and disclose the violation(s) to the Department within 15 calendar days of identifying the violation.

(iv) Upon the Department terminating the use of an approved monitoring plan by an owner or operator, the owner or operator shall comply with the

default monitoring requirements under 20.2.50.16.C(2) NMAC within 30 days.

D. Repair Requirements

(1) For any leaks detected in 20.2.50.16(C) NMAC:

(a) The owner or operator shall place a physical ~~visible~~ tag on the leaking component until the component has been repaired;

(b) All leaks detected ~~using optical gas imaging~~ shall be repaired within 30 ~~7~~ days of discovery~~, all other leaks shall be repaired within 15 days of discovery~~;

(c) The equipment must be re-monitored no later than 30 ~~15~~ days after discovery of the leak to demonstrate that it has been repaired; and

(d) If the leak cannot be repaired within 30 ~~7~~ days ~~for leaks detected using optical gas imaging and within 14 days for all other leaks~~ without a process unit shutdown, or if replacement parts/equipment are unavailable, it may be designated "Delay of Repair" ~~"Repair delayed,"~~ and must be repaired before the end of the next process unit shutdown.

E. Recordkeeping Requirements

(1) Owners or operators shall keep records of all monitoring under 20.2.50.16.C NMAC and provide such records to the Department upon request.

(2) Owners or operators subject to 20.2.50.16.C NMAC shall keep records of the following for all AVO, RM21, and OGI inspections conducted as required under 20.2.50.16.C NMAC:

(a) The facility location ~~and unique inventory control number or name~~;

(b) The date of inspection;

(c) The monitoring method (AVO, RM 21, or OGI);

(d) The name of the operator(s) performing the inspection;

(e) A list of the leaks requiring repair or a statement that no leaks were found; and

(f) Whether a visible flag was placed on the leak or not;

(3) Owners or operators shall keep the following records for any leak detected:

(a) Date the leak is detected;

(b) Dates of attempts to repair;

(c) For leaks with a designation of "delay of repair" ~~"repair delayed"~~ keep the following:

(i) The reason for delay if the leak is not repaired within 30 days of leak discovery;

(ii) The name ~~signature~~ of the authorized representative whose decision it was that the repair could not be implemented without a process shutdown;

(d) The date of successful leak repair;

(e) The date the leak was monitored after the repair and the results of the monitoring; and

(f) A list of components that are designated as unsafe, difficult, or inaccessible to monitor, an explanation stating why the component is so designated, and the schedule for monitoring such component(s).

(4) For leaks determined using optical gas imaging thermal ~~with infrared~~ cameras, owners or operators shall keep the records of the specifications and~~, the daily instrument checks and the~~ leak survey requirements specified in the NSPS subpart

OOOOa, at 40 CFR §60.5397a(a) – (i) OOOOa.~~.18(i)(1) – (3).~~

(5) Owners or operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

F. Reporting Requirements

(1) Owners and operators shall report the certifications required under 20.2.50.16.C(3)(a)(ii) and (b)(ii) NMAC to the Department annually.

(2) Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.17 STANDARDS FOR NATURAL GAS WELL LIQUIDS UNLOADING

A. Applicability

(1) All manual liquids unloading, including those associated with down-hole well maintenance events, performed at natural gas wells are subject to the requirements of 20.2.50.17 NMAC.

(2) Owners and operators shall comply with these requirements for any manual liquids unloading performed after the effective date of this Part.

B. Emission Standards

(1) Owners and operators of natural gas wells shall use best management practices during the life of the well to avoid the need for manual liquids unloading.

(2) Owners and operators of natural gas wells shall use the following best management practices during manual liquids unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) Reduce wellhead pressure prior to blowdown;

(b) Monitor manual liquids unloading in close proximity to the well or via remote telemetry; and

(c) Close all well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) Owners and operators of a natural gas well shall track equipment in an Equipment Database ~~install an Equipment Monitoring and Information Tracking Tag (EMITT) on each natural gas well~~ in accordance with 20.2.50.12 NMAC.

C. Monitoring Requirements

(1) Owners and operators subject to 20.2.50.17 NMAC shall monitor the following parameters during manual liquids unloading:

~~(a) Wellhead pressure;~~

(a) Flow rate of the vented natural gas (to the extent feasible); and

(b) Duration of venting to the storage tank/atmosphere.

(2) Owners and operators shall estimate ~~calculate~~ the volume and mass of VOC vented during each manual liquids unloading event.

~~(3) Each manual liquids unloading event shall include the scanning of the EMITT and monitoring data entry in accordance with the requirements of 20.2.50.12 NMAC.~~

(3) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners and operators subject to 20.2.50.17 NMAC shall keep the following records for each manual liquids unloading:
   (a) The identification number and location of the well;
   (b) The date(s) the manual liquids unloading was performed;
   (c) Wellhead pressure;
   (d) Flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);
   (e) Duration of venting to the storage tank/atmosphere;
   (f) A description of the management practices used to minimize release of VOC prior to and during the manual liquids unloading; and
   (g) An estimate ~~calculation~~ of the VOC emissions vented during the manual liquids unloading based on the duration, volume, and mass of VOC.
(2) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.18 STANDARDS FOR GLYCOL DEHYDRATORS

A. Applicability

(1) All new and existing glycol dehydrators with a potential to emit equal to or greater than 2 tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, ~~natural gas processing plants,~~ and transmission compressor stations are subject to the requirements of 20.2.50.18 NMAC.

B. Emission Standards

(1) Owners and operators of an existing glycol dehydrator constructed on or before the effective date of this Part with a potential to emit equal to or greater than 2 tpy of VOC shall have a minimum combined capture and control efficiency of 95 percent of VOC emissions from the still vent and flash tank, no later than one year after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of 98 percent.
(2) Owners and operators of a new glycol dehydrator constructed after the effective date of this Part with a potential to emit equal to or greater than 2 tpy of VOC shall have a combined capture and control efficiency of 95 percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of 98 percent.
(3) Owners and operators of a new or existing glycol dehydrator subject to control requirements under 20.2.50.18 NMAC shall comply with the following equipment requirements:
   (a) The still vent and flash tank emissions shall be routed at all times to the

reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a vapor recovery unit (VRU) that reinjects the VRU VOC emissions back into the process stream or natural gas gathering pipeline.

(b) If a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that will reinject the natural gas into the process stream or the natural gas gathering pipeline. The VRU shall be operational at least 95 percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of 95 percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications.

(c) The still vent and flash tank emissions shall not be vented to the atmosphere. (d) Owners and operators of a glycol dehydrator shall comply with the equipment database requirements ~~install an Equipment Monitoring and Information Tracking Tag (EMITT)~~ on each glycol dehydrator in accordance with 20.2.50.12 NMAC.

(4) Any new or existing glycol dehydrator subject to control requirements under 20.2.50.18 NMAC will become exempt from these requirements when its uncontrolled actual annual VOC emissions decreases to an amount less than 2 tpy.

(5) Owners and operators complying with the control requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements

(1) The owner or operator of a glycol dehydrator subject to control requirements in 20.2.50.18 NMAC shall ~~conduct an annual extended gas analysis on the dehydrator inlet gas and~~ calculate the uncontrolled VOC emissions (tpy) and controlled VOC emissions (tpy).

(2) The owner or operator of any glycol dehydrator subject to control requirements shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control equipment semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer's recommended procedures.

(3) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners and operators subject to control requirements in 20.2.50.18 NMAC shall maintain records of the following for each glycol dehydrator, in accordance with 20.2.50.12 NMAC:

(a) The dehydrator's location and unique inventory control number or name;

(b) Glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) The data and methodology used to estimate the potential to emit of VOC (the method must be a Department approved calculation methodology);

(d) The controlled and uncontrolled VOC emissions (tpy);
(e) The location, type, make, model and unique identification number of any control equipment;
(f) The date and the results of all equipment inspections, including any maintenance or repairs needed to bring the glycol dehydrator into compliance; and
(g) Copies of the glycol dehydrator manufacturer's operation and maintenance recommendations.

(2) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

(1) Owners and operators complying with the requirements in 20.2.50.18.B(1) NMAC or 20.2.50.18.B(2) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.19 STANDARDS FOR HEATERS

A. Applicability

(1) All new and existing natural gas-fired heater units with a rated heat input equal to or greater than 10 MMBtu/hr including, but not limited to, heater treaters, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, ~~natural gas processing plants,~~ and transmission compressor stations are subject to the requirements of 20.2.50.19 NMAC.

B. Emission Standards

(1) In order to ensure compliance with good combustion engineering practices, the owner or operator of a natural gas-fired heater units shall ensure compliance with the emission limits in Table 1 of 20.2.50.19 NMAC.

Table 1 - Emission Standards for NO_x and CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Natural gas-fired heater units constructed or reconstructed prior to the effective date of this Part shall come into compliance with the requirements of 20.2.50.19 NMAC beginning no later than one year after the effective date.
(3) Natural gas-fired heater units that are constructed or reconstructed on or after the effective date of this Part shall be in compliance with the requirements of this section upon startup.
(4) Owners and operators of a natural gas-fired heater unit shall comply with the equipment database requirements for ~~install an Equipment Monitoring and Information Tracking Tag (EMITT) on~~ each combustion unit in accordance with 20.2.50.12 NMAC.

C. Monitoring Requirements
(1) Owners and operators of natural gas-fired heater units with a rated heat input of greater than or equal to 10 MMBtu/hr shall:
(a) Conduct the monitoring for NOx and CO specified in paragraph C(2) of this section within 180 days of the compliance date specified in the relevant paragraph B(2) or B(3) of this section and every 2 years thereafter.
(b) inspect, maintain, and repair each combustion unit consistent with the manufacturers specifications at least once every 2 years following the compliance date specified in the relevant paragraph B(2) or B(3) of this section. The inspection, maintenance, and repair shall include, at a minimum:
(i) Inspecting the burner and cleaning or replacing any components of the burner as necessary;
(ii) Inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer's specifications or good combustion engineering practices;
(iii) Inspecting the system air-to-fuel ratio controller and ensuring it is calibrated and functioning properly;
(iv) Optimizing total emissions of CO consistent with the NO_x requirement and the manufacturer's specifications or good combustion engineering practices; and
(v) Measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with paragraph C(2)(a) of this section.
(2) Owners and operators of combustion units shall comply with the following combustion unit periodic monitoring requirements:
(a) Conduct three test runs of at least 20-minutes duration within 10% of 100% peak (or the highest achievable) load;
(b) Determine NO_X and CO emissions and O_2 concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522;
(c) If the measured NO_X or CO emissions concentrations are exceeding the emissions limits of Table 1 of this section, the owner or operator shall repeat the inspection and tune-up in paragraph C(1)(b) of this section within 180 days of the periodic monitoring; and

(d) If at any time the owner or operator operates the combustion unit in excess of the highest achievable load plus 10%, the owner or operator shall perform the monitoring specified in paragraph C(2)(a) within 180 days from the anomalous operation.

(3) When conducting periodic monitoring on a combustion unit, the owner or operator shall follow the procedures in paragraph C(2) of this section. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternative procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure to the satisfaction of the Department.

(4) The owner or operator of any combustion unit subject to periodic monitoring, inspections, and/or tune-up shall monitor, inspect, maintain, and repair as required under 20.2.50.19.C NMAC. Each monitoring, inspection, maintenance or repair event shall be tracked in the Equipment Database ~~include the scanning of the EMITT and the simultaneous monitoring data entry~~ in accordance with the requirements of 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) For each combustion unit with a rated heat input of greater than or equal to 10 MMBtu/h, the owner or operator shall maintain the following records in accordance with 20.2.50.12 NMAC:

(a) The location of the combustion unit;

(b) Either the summary for each complete test report described in paragraph C(2) of this section, or the results of each periodic monitoring described in paragraph C(3) this section;

(c) The records of the inspection/maintenance/repair described in paragraph C(1)(c) of this section, which shall include at a minimum:

(i) The date the inspection/maintenance/repair was conducted;

(ii) The concentrations in the effluent stream of CO in ppmv and O_2 in volume percent as determined in paragraph C(2)(a) of this section; and

(iii) A description of any corrective actions taken as part of the inspection/maintenance/repair.

E. Reporting Requirements

Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.20 STANDARDS FOR HYDROCARBON LIQUID TRANSFERS

A. Applicability

(1) All new and existing hydrocarbon liquid transfer operations located at wellheads, tank batteries, gathering and boosting sites, ~~natural gas processing plants,~~ and transmission compressor stations are subject to the requirements of 20.2.50.20 NMAC, beginning on the effective date of this Part.

B. Emission Standards

(1) Owners and operators of all existing and new liquid transfer operations subject to 20.2.50.20 NMAC shall use vapor balance, vapor recovery, or control VOC emissions by 98% or greater using vapor combustion when transferring liquids from storage tanks to transfer vessels, or when transferring liquids from transfer vessels to storage tanks.

(2) Owners and operators using vapor balance during liquid transfer operations shall:

(i) Transfer the vapors displaced from the vessel being loaded back to the vessel being emptied via pipes and/or hoses connected prior to the start of transfer operations;

(ii) Ensure that the transfer does not begin until the vapor collection and return system is connected;

(iii) Maintain connector pipes, hoses, couplers, valves, and pressure relief devices in a condition that prevents leaks;

(iv) Check all liquid and vapor line connections for proper connection prior to commencing transfer operations; and

(v) Operate all transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage tank.

(3) Bottom loading or submerged filling shall be used for all liquids transfers.

(4) Connector pipes and couplers shall be maintained in a condition that prevents leaks.

(5) All connections of hoses or piping used during liquid transfer operations shall be supported on a drip tray that collects any leaks, and any material collected shall be returned to the process or disposed of in a manner compliant with the state law.

(6) Any liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and any material collected shall be returned to the process or disposed of in a manner compliant with the state law.

(7) All owners and operators complying with the control requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements

(1) All transfer equipment must be visually inspected during transfer operations to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. All leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of any liquid transfer operations controlled by air pollution control equipment must follow manufacturer's recommended operation and maintenance procedures.

(3) All tanker trucks or tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(i) Method 27, appendix A, 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of 5 minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 in. H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O

(6 in. H_2O), gauge. The maximum allowable pressure and vacuum changes (Δ p, Δ v) are as shown in Table 1 of this section.

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change

Cargo tank or compartment capacity, liters (gal)	Allowable vacuum change (Δv) in 5 minutes, mm H_2O (in. H_2O)	Allowable pressure change (Δp) in 5 minutes, mm H_2O (in. H_2O)
less than 3,785 (less than 1,000)	64 (2.5)	102 (4.0)
3,785 to less than 5,678 (1,000 to less than 1,500)	51 (2.0)	89 (3.5)
5,678 less than 9,464 (1,500 to less than 2,500)	38 (1.5)	76 (3.0)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)

Commented [SR13]: We recommend that the Department make sure these regulations don't contradict any DOT regulations or rules and that the transportation industry be consulted as to the accuracy and applicability of these numbers.

(ii) Pressure test of the cargo tank's internal vapor valve as follows:

(*A*) After completing the tests under 20.2.50.20.C(3)(i) NMAC, use the procedures in Method 27 to repressurize the tank to 460 mm H_2O (18 in. H_2O), gauge. Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

(*B*) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H_2O (5 in. H_2O).

(4) Owners or operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

(5) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) For each liquid transfer operation, the owner or operator shall maintain records of:

(a) The tank's location and the tank's unique inventory control number or name and,

(b) The location, type, make, and model of any control equipment.

(2) Each owner or operator shall maintain records of the inspections required in 20.2.50.20.C NMAC. These records shall include the following:

(i) the time and date of the inspection;

(ii) the person conducting the inspection;

(iii) a notation that each of the checks required under 20.2.50.20.C NMAC were completed;

(iv) a description of any problems observed during the inspection; and

(v) a description and date of any repairs and corrective actions taken.

(3) Owners and operators shall create and maintain a calendar year record for each site summarizing, calculating, recording, and totaling the liquid loading operation

liquids and associated VOC emissions. Each calendar year, the owners and operators shall create a company-wide record summarizing the liquid transfer total calculated emissions for the company.

(4) Owners and operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(5) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

(1) Owners and operators complying with the requirements in 20.2.50.20.B(1) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.21 STANDARDS FOR PIG LAUNCHING AND RECEIVING

A. Applicability

(1) All new and existing pipeline pig launching and receiving operations located within the property boundary at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.21 NMAC.

B. Emission Standards

(1) The owner or operator of new and existing pipeline pig launching and receiving operations with a potential to emit equal to or greater than 1.0 tpy of VOC shall capture and reduce VOC emissions by at least 98%, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operations shall:

(a) Employ best management practices to minimize the liquids present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and prior to opening the receiving chamber to the atmosphere;

(b) Employ methods to prevent emissions including, but not limited to, installing liquids ramps, installing liquid drains, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers;

(c) Recover and dispose of all receiver liquids in a manner that prevents emissions to the atmosphere; and

(d) Ensure that any material collected is returned to the process or disposed of in a manner compliant with the state law.

(3) Owners and operators of a pig launching and receiving operation shall record ~~install an Equipment Monitoring and Information Tracking Tag (EMITT) on~~ each pig launcher and each pig receiver in the Equipment Database in accordance with 20.2.50.12 NMAC.

(4) Any existing pipeline pig launching and receiving operation subject to control requirements may become exempt from those requirements when its actual annual emissions of VOC decreases to an amount less than 0.5 tpy of VOC.
(5) Owners and operators complying with the control requirements in 20.2.50.21.B(2) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

C. Monitoring Requirements
(1) The owner or operator of any pig launching and receiving equipment shall monitor the type and volume of liquids cleared.
(2) The owner or operator of any pig launching and receiving equipment subject to control requirements shall inspect the equipment for leaks using RM 21 or OGI with infrared cameras immediately prior to the commencement and immediately after the conclusion of each pig launching or receiving operation, and according to the requirements in 20.2.50.16 NMAC.
(3) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.
(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements
(1) Owners and operators shall maintain the following records in accordance with 20.2.50.12.C NMAC for each pig launching and receiving operation or event:
(a) Records of each pigging operation including the date and time of the pigging operation, and the type and volume of liquids cleared; and
~~(b) The data and methodology used to estimate the actual emissions to the atmosphere;~~
~~(c) The data and methodology used to estimate the potential to emit; and~~
(b) The type of control(s), location, make, model and, if applicable, the unique identification number of the control equipment.
(2) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.
(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements
(1) Owners and operators complying with the requirements in 20.2.50.21.B(1) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.
(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.22 STANDARDS FOR PNEUMATIC CONTROLLERS AND PUMPS

A. Applicability

(1) All new and existing natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.22 NMAC.

B. Emission Standards

(1) Natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps constructed on or after the effective date of this Part shall comply with the requirements of 20.2.50.22 NMAC upon startup. Each pneumatic pump and controller shall comply with all applicable NSPS OOOOa requirements.

(2) Natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps constructed before the effective date of this Part shall comply with the requirements of 20.2.50.22 NMAC within three ~~one~~ year of the effective date of this Part.

(3) Standards for natural gas-driven pneumatic controllers.

~~(a) Owners and operators of each pneumatic controller located at a natural gas processing plant shall ensure the pneumatic controller has a VOC emission rate of zero.~~

~~(b) Owners and operators of each pneumatic controller located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station with access to electrical power shall ensure the pneumatic controller has a VOC emission rate of zero.~~

(a) Owners and operators of each pneumatic controller located at a wellhead site, ~~tank battery, gathering and boosting site, or transmission compressor station without access to electrical power~~ shall ensure the pneumatic controller has a bleed rate of less than or equal to 6 standard cubic feet per hour.

(b) Pneumatic controllers with a bleed rate greater than 6 standard cubic feet per hour are permitted where the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including but not limited to response time, safety, and positive actuation.

(c) Owners and Operators that use compressed air to operate pneumatic devices shall be allowed to use natural gas as an emergency back-up in case the onsite air compressor fails.

(4) Standards for natural gas-driven pneumatic pumps.

~~(a) Owners and operators of each pneumatic pump located at a natural gas processing plant shall ensure the pneumatic pump has a VOC emission rate of zero.~~

(a) Owners and operators of each pneumatic pump located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station with access to electrical power shall ensure the pump has a VOC emission rate of zero.

(b) Owners and operators of each pneumatic pump located at a wellhead site, tank battery, gathering and boosting site, or transmission compressor station without access to electrical power shall reduce VOC emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to a

Commented [SR14]: It is imperative that low volume sites are exempted from the control, monitoring and recordkeeping requirements of this section. The cost associated with these requirements on the hundreds of low volume wellsites and tank batteries would make many of the sites uneconomical to produce, with a minute impact on the overall reduction of emissions. Many of these older sites were not designed with any form of emission capture in mind; making for very real technical, logistical and commercial obstacles and hurdles not found in newer locations. These locations would represent some of the most costly sites for industry to address, and have the least impact on emission reductions for the state.

Commented [SR15]: We recommend changing the rules to read "Each Pneumatic Controller and Pump shall comply with all applicable NSPS subpart OOOO requirements." As stated in Federal Register Vol. 81, No. 107 "These standards apply for each newly installed, modified, or reconstructed pneumatic controller (including replacement of an existing controller). The finalized NSPS standards provide exemptions for certain critical applications based on function considerations." We strongly believe the NMED regulations should follow this well researched guideline. In addition, requiring all locations, regardless of construction date or lack of modifications, to comply with the full statute within 12 months is not reasonable. All past regulation in regard to pneumatic devices has employed a phased in implementation schedule, which allows for the targeting of larger volume sites first.

control device, fuel cell, or process.

(c) If there is a control device available onsite, but it is unable to achieve a 95% emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process this section, the owner or operator shall route the pneumatic pump emissions to this control device.

C. Monitoring Requirements

(1) Owners and operators of pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the requirements of this section.

(2) Owners and operators of pneumatic controllers with a natural gas bleed rate greater than zero shall ~~on a monthly basis scan each controller and, considering the EMITT specified design continuous or intermittent bleed rate,~~ conduct an audible, visual, and olfactory (AVO) inspection, according to the AVO schedule in 20.2.50.16, and ~~shall also inspect each pneumatic controller,~~ perform necessary maintenance ~~(such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners),~~ and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

(3) Each pneumatic controller ~~EMITT~~ shall be included in the equipment ~~linked to a~~ database with the following information in accordance with 20.2.50.12: ~~allowing the state inspectors to, at a minimum, identify~~:

(a) unique ~~pneumatic controller and pneumatic pump~~ identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) design annual bleed in standard cubic feet per year.

(4) Owners and operators of a natural gas-driven ~~a~~ pneumatic pump with a natural gas bleed rate greater than zero shall ~~on a monthly basis scan each pump or actuator and, considering the EMITT specified design pump rate or actuation volume,~~ conduct an audible, visual, and olfactory (AVO) inspection according to the AVO schedule in 20.2.50.16 ~~and shall also inspect the pneumatic pump~~ and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the pump's natural gas emissions are minimized.

~~(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.~~

D. Recordkeeping Requirements

(1) Owners and operators of pneumatic controllers, pumps with a natural gas bleed rate equal to zero are not subject to the requirements of this section.

(2) Owners and operators shall maintain records in the Equipment Database ~~an electronic pneumatic controller inspection log~~ for each pneumatic controller with a natural gas bleed rate greater than zero at each facility, including for each inspection:

(a) Unique pneumatic controller ID number;

~~(b) EMITT scanned inspection dates;~~

(b) Name of the inspector;

(c) AVO inspection results;

(d) Any AVO level discrepancy in continuous or intermittent bleed rate;

Commented [SR16]: There is likely to be prohibitive issues with trying to have unique IDs for each pneumatic since there can be multiple devices on a piece of equipment and 100s at a battery.

(e) Maintenance dates; and
(f) Maintenance activities.

(3) Owners and operators who determine that the use of a natural gas-driven pneumatic controller with a bleed rate greater than 6 standard cubic feet per hour is required shall maintain a record in the Equipment Database ~~EMITT database~~ of each such pneumatic controller documenting why a bleed rate greater than 6 standard cubic feet per hour is required per the requirements in 20.2.50.22.B NMAC.

(4) Owners and operators that use compressed air to operate pneumatic devices and have natural gas as an emergency back-up supply shall record in the equipment database all emergency use of natural gas, including date, duration and estimated volume of gas used to operate pneumatics.

(5) Owners and operators shall maintain records in the Equipment Database ~~EMITT database~~ of natural gas-driven pneumatic pumps with an emission rate greater than zero and their associated pump numbers at each facility, including:

(a) For natural gas-driven pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year.

(b) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) Records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(6) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.23 STANDARDS FOR STORAGE TANKS

A. Applicability

(1) All new and existing hydrocarbon storage tanks with an uncontrolled potential to emit equal to or greater than 6 ~~2~~ tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to regulation under 20.2.50.23 NMAC.

B. Emission Standards

(1) All existing storage tanks with a potential to emit equal to or greater than 6 ~~2~~ tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions by at least 95 percent no later than one year after the effective date of this Part.

~~(2) All existing storage tanks with a potential to emit equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions by at least~~

Commented [SR17]: The draft rule's threshold for retrofitting a storage tank with a control device is 2 tons per year (TPY) of volatile organic compounds (VOC). We do not believe this threshold is reasonable, or commercially viable.

1.This is 1/3 of EPA's applicability threshold in NSPS OOOO and OOOOa for controlling new, modified, or reconstructed storage vessels. NSPS OOOO and OOOOa currently require reducing VOC emissions by at least 95% for storage vessels with a PTE equal to or greater than 6 TPY VOC.[1]

2.For instance, in the Small Entity Compliance Guide for Oil and Natural Gas Sector, page 7 (9 of 78), it states, "This rule applies to sources that are constructed, modified or reconstructed after September 18, 2015.

3.As other states have reviewed this issue, states in our region have concluded the 6 tons per year (TPY) was well researched and the most logical threshold; after a thorough review of emission thresholds, commercial viability, and technical feasibility. For example, the states of Texas and Oklahoma follow NSPS guidelines of 6 tons per year. This suggests to us that even after much scrutiny, the 6 ton threshold is most scientifically based; considering all aspects of the decision.

Commented [SR18]: EPA Established Balance between Best System of Emission Reduction and Costs to Implement: EPA did an extensive and thorough review and analysis in developing NSPS OOOO and OOOOa requirements. The 6 TPY threshold reflects the fine balance of considerations of best system of emission reduction and costs to implement.

1.Further, relating to NSPS OOOO, EPA has already determined that a control device's cost effectiveness depends on the amount of vapor produced by a storage vessel, which turns on the storage vessel's throughput. Effectively, EPA found that storage vessels with PTE less than 6 TPY VOC do not have sufficient throughputs to justify installing control devices.

2.Many existing tanks are not equipped to install controls which may result in tank replacement and controls.

3.A requirement to control all existing storage vessels with a TPY equal to or greater than 2 TPY could lead to operators shutting-in or plugging and abandoning wells because analyzing, upgrading, and retrofitting existing low producing/low emitting facilities would not make sense from a cost-benefit perspective.

4.This end result is in direct conflict with New Mexico's Oil and Gas Act.

5.Additionally, if the control device is not installed and operational within 1 year of the effective date of the rule, all wells producing to the tank must be shut-in. This will require industry to install numerous controls in a very short timeframe, which could be technically infeasible for some existing facilities; especially due to supply chain issues related to the COVID-19 pandemic and a dramatic overall industry slowdown and layoffs.

~~98 percent, no later than one year after the effective date of this Part.~~

(2) All new storage tanks constructed after the effective date of this part with a potential to emit equal to or greater than 6 ~~2~~ tpy ~~and less than 10 tpy of VOC~~ shall have a combined capture and control of VOC emissions by at least 95 percent upon startup.

~~(4) All new storage tanks constructed after the effective date of this Part with a potential to emit equal to or greater than 10 tpy of VOC shall have a combined capture and control and control of VOC emissions by at least 98 percent upon startup.~~

(3) Any new or existing storage tank subject to control requirements under 20.2.50.23 NMAC becomes exempt from those requirements when its uncontrolled actual annual VOC emissions decreases to less than 6 ~~2~~ tpy.

~~(6) If air pollution control equipment is not installed by the applicable date specified in 20.2.50.23.B(1) through 20.2.50.23.B(4) NMAC, compliance with 20.2.50.23.B(1) through 20.2.50.23.B(4) NMAC may be demonstrated by shutting in all wells producing into that storage tank by that applicable date and so long as production does not resume from any such well until the air pollution control equipment is installed and operational.~~

~~(7) Owners and operators of an existing or new tank with a thief hatch shall install a control device on the thief hatch which allows the thief hatch to open sufficiently to relieve overpressure in the tank and to automatically close once the tank overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device will only be engaged during in the presence of owner or operator staff and during active ingress activities.~~

(4) Owners and operators of a new or existing hydrocarbon storage tank(s) shall record ~~install an Equipment Monitoring and Information Tracking Tag (EMITT) on~~ each storage tank in the Equipment Database in accordance with 20.2.50.12 NMAC.

(5) Owners and operators complying with the control requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.15 NMAC.

~~(10) After the compliance deadlines established in the rule, it is a violation to operate any tank not complying with the requirements of this section.~~

C. Monitoring Requirements

(1) The owner or operator of any storage tank subject to control requirements shall monitor the total monthly liquid throughput (barrels) and the upstream separator pressure (psig) on a monthly basis. Any time the storage tank is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted prior to the storage tank being unloaded.

(2) The owner or operator of any storage tank subject to control requirements shall conduct an auditory, visual, and olfactory (AVO) inspection on a quarterly basis. ~~weekly basis. Any time the storage tank is unloaded less frequently than weekly, the AVO inspections shall be conducted prior to the storage tank being unloaded.~~

~~(3) The owner or operator of any storage tank subject to control requirements shall inspect the tanks monthly to ensure compliance with the requirements of 20.2.50.23 NMAC. Inspections shall include a check to ensure the tanks have no~~

~~leaks, that all hatches are closed, the pressure relief valves are properly seated, and all vent lines are closed.~~

(3) Each monitoring or inspection shall be recorded in the Equipment Database ~~include the scanning of the EMITT and the simultaneous entry of the required monitoring data~~ in accordance with the requirements of 20.2.50.12 NMAC.

(4) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.15 NMAC.

~~(6) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.~~

D. Recordkeeping Requirements

~~(1) Owners and operators subject to control requirements under 20.2.50.23 NMAC shall, on a monthly basis, maintain records in accordance with 20.2.50.12 NMAC for each storage tank of:~~

~~(a) The tank's location and unique inventory control number or name;~~

~~(b) Monthly liquid throughput and the most recent date of measurement;~~

~~(c) The average monthly upstream separator pressure;~~

~~(d) The data and methodology used to calculate the potential to emit of VOC (the calculation methodology must be a Department approved methodology);~~

~~(e) The controlled and uncontrolled VOC emissions (tpy); and~~

~~(f) The location, type, make, model and unique identification number of any control equipment.~~

~~(2) Records of liquid throughput required in 20.2.50.23.D(1) NMAC shall be verified by dated delivery receipts from the purchaser of the hydrocarbon liquids, or metered volumes of hydrocarbon liquids sent downstream, or other proof of transfer.~~

(1) Records of the inspections required in 20.2.50.23.C NMAC shall include the time and date of the inspection, the person conducting the inspection, a notation that each check required under 20.2.50.23.C NMAC was completed, a description of any problems observed during the inspection, and a description and date of any corrective actions taken in accordance with 20.2.50.12 NMAC.

(2) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.15 NMAC.

(3) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements.

(1) Owners and operators complying with the requirements in 20.2.50.23.B(1) NMAC through 20.2.50.23.B(4) NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

20.2.50.24 STANDARDS FOR WORKOVERS

A. Applicability

(1) All workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.24 NMAC for any workovers performed after the effective date of this Part.

B. Emission Standards

(1) Owners and operators of oil or natural gas wells shall use the following best management practices during workovers to minimize emissions, consistent with well site conditions and good engineering practices:

(a) Reduce wellhead pressure prior to blowdown to minimize the volume of natural gas vented;

(b) Monitor manual venting in close proximity to the well or via remote telemetry; and

(c) Route natural gas flow to the sales line, if possible.

Commented [SR19]: We agree with general standards that require workover operations to reduce wellhead pressure prior to blowdown to minimize the volume of natural gas vented, and to route natural gas flow to the sales line, if possible.

C. Monitoring Requirements

(1) Owners and operators subject to 20.2.50.24 NMAC shall monitor the following parameters during workovers:

(a) Wellhead pressure;

(b) Estimate the flow rate of the vented natural gas (to the extent feasible); and

(c) Duration of venting to the atmosphere.

(2) Owners and operators shall estimate ~~calculate~~ the volume and mass of VOC vented during each workover.

(3) Owners and operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

Commented [SR20]: We do not believe there is existing techniques or approved methodology to measure the flow rate and duration of the small, intermittent gas stream that is vented prior to a workover event; as required in this section.

D. Recordkeeping Requirements

(1) Owners and operators subject to 20.2.50.24 NMAC shall keep the following records for each workover:

(a) The API ~~identification~~ number and location of the well;

(b) The date(s) the workover was performed;

(c) Wellhead pressure;

(d) Estimated flow rate of the vented natural gas (to the extent feasible. If measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) Duration of venting to the atmosphere;

(f) A description of the management practices used to minimize release of VOC prior to and during the workover; and

(g) An estimation ~~calculation~~ of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) Owners and operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

E. Reporting Requirements

(1) Owners and operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

~~(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from any workover event, the owner or operator shall notify all~~

Commented [SR21]: The requirement to notify all residents by certified mail with 0.25 miles of the well of the planned workover at least three (3) calendar days prior to a workover event is not feasible; and not reasonable based on the small volume of methane emissions these events represent. It may not be possible in populated areas, especially with wellsites located inside city limits and residential areas; and would represent a huge execution challenge and administrative cost to the industry with no positive impact to emission reductions.

~~residents by certified mail located within 0.25 miles of the well of the planned workover at least three (3) calendar days prior to the workover event.~~

20.2.50.25 STANDARDS FOR OIL AND NATURAL GAS STRIPPER WELLS AND FACILITIES WITH SITE-WIDE VOC POTENTIAL TO EMIT LESS THAN 15 TPY

A. Applicability

(1) Stripper Well Facilities ~~wells~~, defined as any oil and natural gas well producing less than 15 ~~10~~ barrels of oil equivalent per day ~~or less than 60 thousand standard cubic feet of natural gas per day,~~ are subject to the requirements of 20.2.50.25 NMAC and are exempt from all other requirements of 20.2.50 NMAC.

(2) Owners or operators of Stripper Well Facilities ~~stripper wells~~ shall comply with these requirements no later than one year after the effective date of this Part.

(3) Facilities with a site-wide annual PTE of less than 25 ~~15~~ tons per year of VOC are subject to the requirements of 20.2.50.25 NMAC.

(4) Owners or operators of facilities with a site-wide annual PTE of less than 25 ~~15~~ tons per year of VOC shall comply with these requirements no later than one year after the effective date of this Part.

(5) If at any time a facility identified in 20.2.50.25.A(1) or (3) NMAC exceeds the daily production limit or PTE threshold of 25 ~~15~~ tpy of VOC, the owner or operator shall conduct semi-annual LDAR monitoring as required by 20.2.50.16.C(2)(b) NMAC for a period of one ~~two~~ years.

B. Emission Standards

(1) Owners or operators shall ensure that all equipment located at a Stripper Well Facility ~~stripper well or low-PTE facility~~ shall be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the Department.

(2) Owners or operators of an oil or natural gas Stripper Well Facility ~~stripper well or individual facility~~ with a site-wide PTE less than 25 ~~15~~ tpy of VOC shall, within the first calendar quarter of the year, use actual production volumes to calculate the VOC and NOx emissions from the stripper well site.

(3) Owners or operators of an oil or natural gas Stripper Well Facility ~~stripper well(s) or facility(s)~~ with a site-wide PTE less than 25 ~~15~~ tpy of VOC shall maintain a database of company- wide calculated VOC and NOx emissions estimates for each site and must update the database annually.

~~C. Monitoring Requirements~~

~~(1) Owners or operators complying with 20.2.50.25 NMAC shall monitor the following for each stripper well or facility with a site-wide PTE of VOC less than 15 tpy:~~

~~(a) the unique identifier of the stripper well or facility (number and name, as applicable);~~

~~(b) the UTM coordinates of the stripper well or facility and its county of location;~~

Commented [SR22]: Alternative Language: Stripper well facilities, as defined in 20.2.50.8, which includes an individual Wellhead Site, are only subject to the requirements of 20.2.50.25 NMAC.

Commented [SR23]: Would be removed entirely if alternative language is adopted.

~~(c) the annual total well production rate in barrels of oil per year and natural gas production in thousand standard cubic feet per year; and~~

~~(d) Dates, duration, and VOC emission estimates of any venting or flaring event longer than eight (8) hours.~~

~~(2) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.~~

C. Recordkeeping Requirements

(1) Owners or operators complying with 20.2.50.25 NMAC shall:

(a) maintain electronic records of the following for each Stripper Well Facility ~~stripper well and low-PTE facility~~:

(i) the unique identifier of the stripper well and low-PTE facility (API number and name, as applicable);

(ii) the Latitude/Longitude ~~UTM~~ coordinates of the stripper well and low-PTE facility and its county of location;

(iii) the total annual well production in barrels of oil per year and natural gas production in thousand standard cubic feet; and

(iv) Dates, duration, and VOC emission calculation of any venting or flaring event lasting longer than eight (8) hours, and the cause of the event.

~~(2) Within the first calendar quarter of the year, record the calculated total annual emissions of VOC and NOx from each stripper well site and low-PTE facility in tons, and the company-wide total VOC and NOx emissions from stripper wells and low-PTE facilities in tons. All venting and flaring emissions shall be included in the calculated total annual emissions.~~

(2) Within the first calendar quarter of the year, provide a description of the management practices used to minimize and prevent the release of VOC and NOx at each stripper well and low-PTE facility.

~~(4) Owners or operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.~~

D. Reporting Requirements

Owners or operators shall submit Stripper Well Facility emission calculations upon written request from the Department. ~~comply with the reporting requirements in 20.2.50.12 NMAC.~~

20.2.50.26 STANDARDS FOR EVAPORATION PONDS

A. Applicability

(1) All new and existing oil and natural gas evaporation ponds with pond capacity equal to or greater than [TBD barrels] or a potential to emit greater than [10 lbs/day VOC] and located at wellhead sites, tank batteries, gathering and boosting sites~~, natural gas processing plants~~, transmission compressor stations, or not associated with a facility but located in San Juan, Lea, Eddy, Rio Arriba, Sandoval counties are subject to the requirements of 20.2.50.26 NMAC.

(2) Owners or operators of oil and natural gas evaporation ponds shall comply with these requirements no later than 180 days after the effective date of this Part.

Commented [SR24]: US EPA has written OOOO and OOOOa emissions rules pertaining to produced water treatment as part of water recycling efforts. Advanced computations show that emissions of VOCs are expected to be almost non-existent from PW storage ponds, even when the PW was high in TDS. This is especially true when the treatment involves certain strong oxidizers that effectively break hydrocarbon emulsions (e.g. chlorine dioxide). Operators are highly motivated to collect the floating hydrocarbons for profit during early PW treatment phases. As a consequence, US EPA Office of Air wrote regulatory language that largely minimizes specific controls on VOCs at produced water treatment facilities for recycle.

Certainly, there has been some evolution in produced water treatment techniques in general. The quality of produced water (PW) from the reservoir is the main criteria driving any treatment system design and there is a broad range of PW quality even in New Mexico depending on geography and reservoir. Especially in the Delaware basin some reservoirs generate produced water of relatively high quality, with TDS approximating sea water, and for various chemical reasons the water retains very little hydrocarbon content in emulsion after mechanical separation. This type of water requires minimal treatment apart from aerobic aeration before being recycled for fracking.

Commented [SR25]: Lacks sufficient specificity and clarity. Operators cannot confidently discern which facilities the code intends to include. They will react by presuming the rule is written to include all forms of *Pits* (19.15.17 NMAC), *Evaporation, Storage, Treatment and Skimmer Ponds* (19.15.36.17 NMAC) and that it intends to supersede regulations recently enacted to encourage produced water re-use and recycling by ignoring provisions for "Recycling facilities" "Recycling containment" and "Treatment" (19.15.34 NMAC). This is especially troublesome and might shut down substantial production in Lea and Eddy counties. Moreover developing, permitting (where required), and construction of replacement infrastructure suitable to NMED may take years depending on specifics. Also, evaporation ponds are typically used in the upstream.

Commented [SR26]: In our view, it is inappropriate to discuss a timeline for implementation [e.g. 180 days] until the scope of required modifications is clearly defined and understood.

B. Emission Standards

(1) Owners or operators of an oil or natural gas evaporation pond shall use best management practices to minimize emissions of VOC, consistent with good engineering practices.

(2) Prior to unloading into a pond(s), all liquids shall be first loaded into a 20.2.50.23 NMAC compliant liquid storage tank designed to minimize subsequent VOC emissions from the pond.

Commented [SR27]: Evaporation ponds are typically used in the upstream oil and gas industry to reduce the amount of produced water that is re-injected back into a formation via a salt water disposal well (SWD), by allowing a portion of the water volume to evaporate from a "evaporation pond"; then transporting a reduced volume of more concentrated brine to a SWD well (either via truck or pipeline). Reducing these re-injection volumes benefits both the state and industry in many ways. The requirement to load all produced water through a NMAC compliant liquid storage tank to minimize VOC emissions, prior to unloading into the pond, should be limited to those locations with the potential to emit (PTE) 6 tons or more of VOC's. This will allow large evaporation ponds to fall under the same threshold as if the pond was a tank. The subsequent requirement in section (3) doesn't seem to make sense – as it requires operators to "install an impermeable continuous barrier or cover over the entire surface area of the liquid, which prevents VOC emissions from being emitted to atmosphere". There is no technology that allows for water vapor to pass through (aka evaporate) a barrier but does not allow VOC's to pass through. We believe this language may have originated from "ponds" in the chemical or downstream sector, which serve a completely different technical function that upstream "evaporation ponds". An impenetrable barrier cannot be placed over an evaporation pond, or it ceases to function as an evaporation pond.

Commented [SR28]: The utility of the proposed tank equipment is a function of both fluid composition itself and the comprehensive design of fluid treatment process including both mechanical and chemical treatment schemes. Systems to remove hydrocarbons from water need to be understood holistically. In some circumstances a tank with VOC recovery might be a helpful addition while in other situations, it might actually make things worse in terms of avoided emissions.
Specifically, for some qualities of produced water treated for recycle, applications of flotation chemistries breaking emulsions have proved highly effective. In such systems, it is especially important to encourage large scale chemical equilibration of PW effectively "holding" water 24-48 hours before treatment in large open "ponds" (already benefiting from mechanical separation). Active hydrocarbon skimming is part of the process.
Critically, after the comprehensive treatment the resulting PW is "clean" and literally millions of barrels of produced water stored in recycling containment do not emit significant measurable VOC's.

(3) Owners or operators shall install an impermeable continuous barrier or cover over the entire surface area of the liquid, which prevents VOC emissions from being emitted to the atmosphere. Owners and operators shall ensure that VOC emissions are collected and routed to a control device for destruction.

C. Monitoring Requirements

(1) For each oil or natural gas evaporation pond, the owners or operators subject to 20.2.50.26 NMAC shall:

(a) on a monthly basis, perform an inspection to ensure that the barrier is an impermeable continuous barrier or cover that covers the entire surface area of liquid;

(b) on a monthly basis, ensure that all VOC emissions are being captured and routed to a control device; and

(c) monitor the monthly total and annual total oil and natural gas evaporation pond throughput in thousands of gallons of liquids.

(2) Owners or operators shall comply with the monitoring requirements in 20.2.50.12 NMAC.

D. Recordkeeping Requirements

(1) Owners or operators subject to 20.2.50.26 NMAC shall maintain electronic records of the following for each evaporation pond:

(a) the unique identifier of the evaporation pond (number and name, as applicable);

(b) the longitude and latitude ~~UTM~~ coordinates of the evaporation pond site and its county of location; (c) the results of the barrier or cover inspection, including the date, time, and name of the personnel performing the inspection;

(d) the results of the VOC capture and control device inspection, including the date, time, and name of the personnel performing the inspection; and

(e) the total calculated VOC emissions in tons per year.

(2) Owners or operators of an oil or natural gas evaporation pond shall, within the first calendar quarter of the year, record the calculated emission estimates of VOC from the evaporation pond in tons per year.

(3) Owners or operators of an oil or natural gas evaporation pond shall record a description of the management practices used to minimize release of VOC at the evaporation pond, and the company-wide total VOC emissions from evaporation ponds in tons per year.

(4) Owners or operators of an oil or natural gas evaporation pond shall, within the first calendar quarter of the year, use actual volumes of liquid loaded into each site's pond(s) to calculate total site-wide VOC emissions from all evaporation ponds.

(5) Owners or operators of an oil or natural gas evaporation pond(s) shall maintain a database of company-wide calculated annual total VOC emissions estimates in tons per year from each pond.

(6) Owners or operators shall comply with the recordkeeping requirements in 20.2.50.12 NMAC.

Commented [SR29]: Most produced water treatment facilities include large surface area, open-air water storage "recycling containment" for both treatment and short-term storage. Evaporation is an uncontrollable consequence of other essential design choices including aeration and ultra-violet light (sunlight) requirements to minimize bacterial growth, water stratification, and especially in some cases to prevent the development of anerobic layers which have the potential to lead to H2S.
Over the years across the Permian Basin several operators experimented with systems to cover large fresh water and large treated produced water containment facilities motivated mostly to minimize evaporation loses. It is generally acknowledged that all of these efforts proved operational failures in spite of some contrary claims by vendors. Bacteria counts increased many orders of magnitude and large amounts of biocides were administered but failed to control the situation especially with "on-the-fly" applications from the "ponds" to the frack site.
In several cases operators shared "confidentially between themselves" that reservoirs soured more rapidly than expected after these impaired waters were used in fracking. Remediation costs greatly exceeded the value of controlling any evaporated water.
Today it is rare to see covers on any water treatment ponds, and aeration is almost universal. More to the point, VOC emissions above treated containment tend to be minimal, and any covers would still require a completely different engineered system to collect gases, and it is difficult to imagine how that would work at large scale.

E. Reporting Requirements

Owners or operators shall comply with the reporting requirements in 20.2.50.12 NMAC.

~~20.2.50.27 PROHIBITED ACTIVITIES AND CREDIBLE INFORMATION PRESUMPTIONS~~

~~A. Failure to comply with any of the emissions standards, recordkeeping, reporting, or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 of the Act.~~

~~B. If credible information obtained by the Department indicates that a source is not in compliance with any provision of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~

~~C. If credible information provided to the Department by a member of the public indicates that a source is not in compliance with any provision of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 7 FORMS AND REPORTS

19.15.7.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.7.1 NMAC - Rp, 19.15.13.1 NMAC, 12/1/2008]

19.15.7.2 SCOPE: 19.15.7 NMAC applies to persons or entities engaged in oil and gas development and production within New Mexico.
[19.15.7.2 NMAC - Rp, 19.15.13.2 NMAC, 12/1/2008]

19.15.7.3 STATUTORY AUTHORITY: 19.15.7 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12 NMSA 1978.
[19.15.7.3 NMAC - Rp, 19.15.13.3 NMAC, 12/1/2008]

19.15.7.4 DURATION: Permanent.
[19.15.7.4 NMAC - Rp, 19.15.13.4 NMAC, 12/1/2008]

19.15.7.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.7.5 NMAC - Rp, 19.15.13.5 NMAC, 12/1/2008]

19.15.7.6 OBJECTIVE: To provide for the filing of reports to enable the division to carry out its statutory mandates under the Oil and Gas Act.
[19.15.7.6 NMAC - Rp, 19.15.13.6 NMAC, 12/1/2008]

19.15.7.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.7.8 GENERAL:

A. Where to file reports. Unless otherwise specifically provided for in a division rule or order, the operator shall file forms and reports 19.15.7 NMAC requires with the appropriate division district office as provided in 19.15.2.17 NMAC and 19.15.7.10 NMAC.

B. Additional data. 19.15.7 NMAC does not limit or restrict the division's authority to require the furnishing of additional reports, data or other information relative to the production, transportation, storing, refining, processing or handling of oil, gas or products in the state as may appear to the division to be necessary or desirable, either generally or specifically, for the prevention of waste and the conservation of the state's natural resources.

C. Books and records. A producer, injector, transporter, storer, refiner, gasoline or extraction plant operator, treating plant operator and initial purchaser of gas within the state shall make and keep appropriate books and records for a period of not less than five years, covering operations in New Mexico, in order to make and substantiate the reports the division requires.

D. Written notices, requests, permits and reports. A person required to file notices, requests, permits or reports shall use the forms listed below for the purpose shown in accordance with the instructions printed on the form and the rule covering the form's use or special order pertaining to its use:

(1) form C-101 - application for permit to drill, deepen or plug back;

(2) form C-102 - well location and acreage dedication plat;
(3) form C-103 - sundry notices and reports on wells;
(4) form C-104 - request for allowable and authorization to transport oil and gas;
(5) form C-105 - well completion or recompletion report and log;
(6) form C-106 - notice of intention to utilize automatic custody transfer equipment;
(7) form C-107 - application for multiple completion;
(8) form C-107-A - application for downhole commingling;
(9) form C-107-B - application for surface commingling (diverse ownership);
(10) form C-108 - application to dispose of salt water by injection into a porous formation;
(11) form C-109 - application for discovery allowable and creation of a new pool;
(12) form C-111 - gas transporter's monthly report (sheet 1 and sheet 2);
(13) form C-112 - transporter's and storer's monthly report;
(14) form C-112-A - receipts continuation sheet;
(15) form C-112-B - deliveries continuation sheet;
(16) form C-113 - refiner's monthly report (sheet 1 and sheet 2);
(17) form C-115 - operator's monthly report;
(18) form C-115B – volume of vented and flared natural gas;
(19) form C-115-EDP - operator's monthly report (electronic data processing);
(20) form C-116 - gas-oil ratio tests;
(21) form C-117-A - tank cleaning, sediment oil removal, transportation of miscellaneous hydrocarbons and disposal permit;
(22) form C-117-B - monthly sediment oil disposal statement;
(23) form C-118 - treating plant operator's monthly report (sheet 1 and sheet 2);
(24) form C-120-A - monthly water disposal report;
(25) form C-121 - oil purchaser's nomination;
(26) form C-121-A - purchaser's gas nomination;
(27) form C-122 - multi-point and one point back pressure test for gas wells;
(28) form C-122-A - gas well test data sheet-San Juan basin (initial deliverability test, blue paper; annual deliverability test, white);
(29) form C-122-B - initial potential test data sheet;
(30) form C-122-C - deliverability test report;
(31) form C-122-D - worksheet for calculation of static column wellhead pressure (P_w);
(32) form C-122-E - worksheet for stepwise calculation of (surface) (subsurface) pressure (P_c and P_w);
(33) form C-122-F - worksheet for calculation of wellhead pressures (P_c or P_w) from known bottom hole pressure (P_f or P_s);
(34) form C-122-G - worksheet for calculation of static column pressure at gas liquid interface;
(35) form C-123 - request for the creation of a new pool;
(36) form C-124 - reservoir pressure report;
(37) form C-125 - gas well shut-in pressure report;
(38) form C-126 - permit to transport recovered load oil;
(39) form C-127 - request for allowable change;
(40) form C-129 – report of vented or flared natural gas;

(41) form C-130 - notice of disconnection;
(42) form C-131-A - monthly gas storage report;
(43) form C-131-B - annual LPG storage report;
(44) form C-133 - authorization to move produced water exhibit "A";
(45) form C-134 - application for exception to division order R-8952, 19.15.18.18 NMAC or 19.15.36 NMAC;
(46) form C-135 - gas well connection, reconnection or disconnection notice;
(47) form C-136 - application for approval to use an alternate gas measurement method;
(48) form C-137 - application for waste management facility;
(49) form C-137-EZ - registration/final closure report for small landfarm;
(50) form C-138 - request for approval to accept solid waste;
(51) form C-139 - application for qualification of production restoration project and certification of approval;
(52) form C-140 - application for qualification of well workover project and certification of approval;
(53) form C-141 - release notification and corrective action;
(54) form C-144 - pit, closed-loop system, below-grade tank or proposed alternative method permit or closure plan application;
(55) form C-145 - change of operator; and
(56) form C-146 - change of operator name.
[19.15.7.8 NMAC - Rp, 19.15.13.1100 NMAC, 12/1/2008]

19.15.7.9 FORMS UPON REQUEST: The division's forms for written notices, requests and reports it requires are available on the division's website. The division shall furnish paper copies upon request.
[19.15.7.9 NMAC - Rp, 19.15.1.16 NMAC, 12/1/2008]

19.15.7.10 WHERE TO FILE REPORTS AND FORMS: A person required to file a report or form shall file the report or form with the division in the number and at the time specified on the form or report or by the applicable section in 19.15.7 NMAC. An operator shall file plugging bonds directly with the division's Santa Fe office.
[19.15.7.10 NMAC - Rp, 19.15.15.1302 NMAC, 12/1/2008]

19.15.7.11 UNITED STATES GOVERNMENT LEASES: For wells located on land that the United States or a native american nation, tribe or pueblo owns, an operator shall file applications for permit to drill, deepen or plug back, BLM form no. 3160-3; sundry notices and reports on wells, BLM form no. 3160-5; and well completion or recompletion report and log, BLM form no. 3160-4 with the BLM in lieu of filing the corresponding division forms with the division. All such forms are, however, subject to division approval in the same manner and to the same extent as the corresponding division forms.
[19.15.7.11 NMAC - Rp, 19.15.1.14 NMAC, 12/1/2008]

19.15.7.12 APPLICATION FOR PERMIT TO DRILL, DEEPEN OR PLUG BACK (Form C-101): Form C-101 is the form an operator uses to apply for a permit to drill, deepen, re-enter or plug a well back to a different pool or complete or re-complete a well in an additional pool.
[19.15.13.12 NMAC - Rp, 19.15.13.1101 NMAC, 12/1/2008]

19.15.7.13 WELL LOCATION AND ACREAGE DEDICATION PLAT (Form C-102):

A. Form C-102 is a dual purpose form the operator uses to show the well's exact location and the acreage dedicated to the well. The form is also used to show the ownership and status of each lease contained within the dedicated acreage. When there is more than one working interest or royalty owner on a given lease, designation of the majority owner et al. is sufficient.

B. An operator shall fill out and certify the information required on form C-102 except the well location on the plat. A professional surveyor, registered in the state of New Mexico, or surveyor approved by the division, shall plot and certify the well location on the plat from the section's outer boundaries.

C. An operator shall file amended form C-102 in the event there is a change in the information the operator previously submitted. The operator does not need to provide certification of the well location when filing amended form C-102.

[19.15.13.13 NMAC - Rp, 19.15.13.1102 NMAC, 12/1/2008]

19.15.7.14 SUNDRY NOTICES AND REPORTS ON WELLS (Form C-103): Form C-103 is a dual purpose form the operator files with the appropriate division district office to obtain division approval prior to commencing certain operations and to report various completed operations.

A. Form C-103 as a notice of intention.

(1) An operator shall file form C-103 and obtain the division's approval prior to:

(a) effecting a change of plans from those the division previously approved on form C-101 or form C-103;

(b) altering a drilling well's casing program or pulling casing or otherwise altering an existing well's casing installation;

(c) making multiple completions in a well;

(d) placing a well in approved temporary abandonment;

(e) plugging and abandoning a well;

(f) performing remedial work on a well that, when completed, will affect the well's original status (this includes making new perforations in existing wells or squeezing old perforations in existing wells, but does not apply to new wells in the process of being completed nor to old wells being deepened or plugged back to another zone when the division has authorized the recompletion by an approved form C-101, application for permit to drill, re-enter, deepen plug back or add a zone, nor to acidizing, fracturing or cleaning out previously completed wells, nor to installing artificial lift equipment); or

(g) downhole commingling in well bores, within pools or areas that the division has established as pre-approved pools or areas.

(2) In the case of well plugging operations, the notice of intention shall include a detailed statement of the proposed work including plans for shooting and pulling casing; plans for mudding, including the mud's weight; plans for cementing, including number of sacks of cement and depths of plugs; restoration and remediation of the location; and the time and date of the proposed plugging operations. The operator shall file a complete log of the well on form C-105 with the notice of intention to plug the well, if the operator has not previously filed the log (see 19.15.7.16 NMAC); the division shall not release the financial assurance until the operator complies with this requirement.

B. Form C-103 as a subsequent report.

(1) The operator shall file form C-103 as a subsequent report of operations in accordance with 19.15.7.14 NMAC as applicable to the particular operation being reported.

(2) The operator shall use form C-103 in reporting such completed operations as:

(a) commencement of drilling operations;

(b) casing and cement test;

(c) altering a well's casing installation;
(d) work to secure approved temporary abandonment;
(e) plugging and abandonment;
(f) plugging back or deepening within the same pool;
(g) remedial work;
(h) installation of artificial lifting equipment; or
(i) other operations that affect the well's original status but that are not specifically covered in 19.15.7.14 NMAC.

C. Report of commencement of drilling operations. Within 10 days following the commencement of drilling operations, the operator shall file a report of commencement on form C-103. The report shall indicate the hour and the date the operator spudded the well.

D. Report of results of test of casing and cement job; report of casing alteration. The operator shall file a report of casing and cement test within 10 days following the setting of each string of casing or liner. The operator shall file the report on form C-103 and include a detailed description of the test method employed and the results obtained by the test and any other pertinent information 19.15.16.10 NMAC requires. The report shall also indicate the top of the cement and the means by which the operator determined the top. It shall also indicate any changes from the casing program previously authorized for the well.

E. Report of temporary abandonment. The operator shall file a notice of work to secure approved temporary abandonment within 30 days following the work's completion. The report shall present a detailed account of the work done on the well, including location and type of plugs used, if any, and status of surface and downhole equipment and any other pertinent information relative to the well's overall status.

F. Report on plugging of well.

(1) The operator shall file a report of plugging operations within 30 days following completion of plugging operations on a well. The operator shall file the report on form C-103, which shall include the date the operator began plugging operations and the date the operator completed the work, a detailed account of the manner in which the operator performed the work including the depths and lengths of the various plugs set, the nature and quantities of materials employed in the plugging operations including the weight of the mud used, the size and depth of all casing left in the hole and any other pertinent information. (See 19.15.25 NMAC regarding plugging operations.)

(2) The division shall not approve a plugging report until the operator demonstrates compliance with Subsection B of 19.15.25.10 NMAC. The operator shall contact the appropriate division district office when the operator has restored the location in order to arrange for a division representative's inspection of the plugged well and the location.

G. Report of remedial work. The operator shall file a report of remedial work performed on a well within 30 days following the work's completion. The operator shall file the report on form C-103 and present a detailed account of the work done and the manner in which the operator performed the work; the daily production of oil, gas and water both prior to and after the remedial operation; the size and depth of shots; the quantity and type of crude, chemical or other materials the operator employed in the operation; and any other pertinent information. Among the remedial work an operator shall report on form C-103 are the following:

(1) report on shooting, fluid fracturing or chemical treatment of a previously completed well;
(2) report of squeeze job;
(3) report on setting of liner or packer;
(4) report of installation of pumping equipment or gas lift facilities; or

(5) report of any other remedial operations that are not specifically covered herein.

H. Report on deepening or plugging back within the same pool. An operator shall file a report of deepening or plugging back within 30 days following completion of the operations on a well. The operator shall file the report on form C-103 and present a detailed account of work done and the manner in which the operator performed the work. If the operator recompletes the well in the same pool, the operator shall also report the daily production of oil, gas and water both prior to and after recompletion. If the well is recompleted in another pool, the operator shall file forms C-101, C-102, C-104 and C-105 in accordance with 19.15.7.12 NMAC, 19.15.7.13 NMAC, 19.15.7.15 NMAC and 19.15.7.16 NMAC.

I. **Other reports on wells.** The operator shall submit reports on other operations that affect the well's original status but that are not specifically covered in 19.15.7.14 NMAC to the division on form C-103 10 days following the operation's completion.

[19.15.7.14 NMAC - Rp, 19.15.13.1103 NMAC, 12/1/2008]

19.15.7.15 REQUEST FOR ALLOWABLE AND AUTHORIZATION TO TRANSPORT OIL AND GAS (Form C-104): An operator shall file with the division a complete form C-104 to request the division assign an allowable to a newly completed or re-completed well or a well completed in an additional pool or issue an operator authorization to transport oil or gas from the well.

[19.15.7.15 NMAC - Rp, 19.15.13.1104 NMAC, 12/1/2008]

19.15.7.16 WELL COMPLETION OR RECOMPLETION REPORT AND LOG (Form C-105):

A. Within 45 days following the completion or recompletion of a well, the operator shall file form C-105 with the appropriate division district office accompanied by a summary of special tests conducted on the well, including drill stem tests. In addition, the operator shall file a copy of electrical and radio-activity logs run on the well with form C-105. If the division does not receive form C-105 with attached logs and summaries within the specified 45-day period, the division shall withhold the allowable for the well until the operator has complied with 19.15.7.16 NMAC.

B. In the case of a dry hole, a complete record of the well on form C-105 with the attachments listed in Subsection A of 19.15.7.16 NMAC shall accompany the notice of intention to plug the well, unless previously filed. The division shall not approve the plugging report or release the bond the operator has complied with 19.15.7.16 NMAC.

C. The division shall not keep form C-105 and accompanying attachments confidential unless the well's owner requests in writing that the division keep it confidential. Upon such request, the division shall keep these data confidential for 90 days from the date of the well's completion, provided, however, that the report, logs and other attached data may, when pertinent, be introduced in a public hearing before division examiners, the commission or in a court of law, regardless of the request that they be kept confidential.

[19.15.7.16 NMAC - Rp, 19.15.13.1105 NMAC, 12/1/2008; A, 9/26/2017]

19.15.7.17 NOTICE OF INTENTION TO UTILIZE AUTOMATIC CUSTODY TRANSFER EQUIPMENT (Form C-106): An operator intending to use an ACT system shall file form C-106, when applicable, in accordance with Subsection A of 19.15.18.15 NMAC.

[19.15.7.17 NMAC - Rp, 19.15.13.1106 NMAC, 12/1/2008]

19.15.7.18 APPLICATION FOR MULTIPLE COMPLETION (Form C-107): An operator shall file form C-107, when applicable, in accordance with Subsection A of 19.15.16.15 NMAC.

[19.15.7.18 NMAC - Rp, 19.15.13.1107 NMAC, 12/1/2008]

19.15.7.19 APPLICATION FOR AUTHORIZATION TO INJECT (Form C-108): An operator shall file form C-108 in accordance with Subsection B of 19.15.26.8 NMAC.
[19.15.7.19 NMAC - Rp, 19.15.13.1108 NMAC, 12/1/2008]

19.15.7.20 APPLICATION FOR DISCOVERY ALLOWABLE AND CREATION OF A NEW POOL (Form C-109): An operator shall file form C-109, when applicable, in accordance with 19.15.20.16 NMAC.
[19.15.7.20 NMAC - Rp, 19.15.13.1109 NMAC, 12/1/2008]

19.15.7.21 GAS TRANSPORTER'S MONTHLY REPORT (Form C-111):

A. An operator shall complete and maintain for the division's inspection, form C-111 monthly in accordance with Subsections B, C and D of 19.15.7.21 NMAC. The transporter shall itemize information on sheet no. 2 of form C-111 by pool, by operator and by lease, in alphabetical order.

B. An operator of a gas gathering system, gas transportation system, recycling system, fuel system, gas lift system, gas drilling operation, etc. shall complete and maintain for division inspection form C-111 each month. The form shall cover gas, casinghead gas and carbon dioxide gas taken into a system during the preceding month and shall show the gas' source and its disposition.

C. An operator of a gasoline plant, cycling plant or other plant at which gasoline, butane, propane, kerosene, oil or other products are extracted from gas within the state shall complete and maintain for the division's inspection form C-111 each month. The form shall cover gas, casinghead gas and carbon dioxide gas the plant has taken during the preceding month and shall show the gas' source and its disposition. If an operator owns more than one plant in a given division district, the operator shall file sheet no. 1 of form C-111 for each plant. In preparing sheet no. 2, the operator shall consolidate requisitions for plants in the district, itemized in the order described in the Subsection A of 19.15.7.21 NMAC.

D. Where a producer takes gas and uses it for any of the above uses, the producer shall complete and maintain for division inspection form C-111 itemizing such gas. The producer shall also include this gas on form C-115. The producer shall also include gas used on the lease from which it was produced for consumption in lease houses, treaters, compressors, combustion engines and other similar equipment, or gas that is flared, on the form C-115 but shall not include it on form C-111.
[19.15.7.21 NMAC - Rp, 19.15.13.1111 NMAC, 12/1/2008]

19.15.7.22 TRANSPORTER'S AND STORER'S MONTHLY REPORT (Form C-112): A transporter or storer of oil and liquid hydrocarbons within the state shall complete and maintain for division inspection for each calendar month a form C-112 containing complete information and data indicated by the form respecting stocks of oil and liquid hydrocarbons on hand and receipts and deliveries of oil and liquid hydrocarbons by pipeline and trucks within the state, and receipts and deliveries from leases to storers or refiners; between transporters within the state; between storers and refiners within the state.
[19.15.7.22 NMAC - Rp, 19.15.13.1112 NMAC, 12/1/2008]

19.15.7.23 REFINER'S MONTHLY REPORT (Form C-113): A refiner of oil within the state shall file for each calendar month form C-113 containing the information and data indicated by the form respecting oil and products involved in the refiner's operation during each month. The refiner shall file the completed form C-113 for each month and postmark it on or before the 15th day of the next succeeding month.
[19.15.7.23 NMAC - Rp, 19.15.13.1113 NMAC, 12/1/2008]

19.15.7.24 OPERATOR'S MONTHLY REPORT (Form C-115):

A. An operator shall file a form C-115 for each non-plugged well completion for which the division has approved a form C-104 and for each secondary or other enhanced recovery project or pressure maintenance project injection well or other injection well within the state, setting forth complete information and data indicated on the forms in the order, format and style the director prescribes. The operator shall estimate oil production from wells producing into common storage as accurately as possible on the basis of periodic tests.

B. An operator shall file form C-115 using the division's web-based online application on or before the 15th day of the second month following the month of production, or if such day falls on a weekend or holiday, the first workday following the 15th. ~~no later than the 30th day of the month following the month of production~~. An operator may apply to the division for exemption from the electronic filing requirement based upon a demonstration that such requirement would be an economic or other hardship.

Commented [SR1]: We recommend keeping the current requirement for filing C-115s.

C. If an operator fails to file a form C-115 that the division accepts, the division shall, within 30 days of the appropriate filing date, notify the operator by electronic mail or letter of its intent to cancel the operator's authorization to transport or inject if the operator does not file an acceptable and complete form C-115. The notice shall inform the operator of the right to request a hearing pursuant to 19.15.4.8 NMAC. If the operator does not either file an acceptable and complete form C-115 or request a hearing on the proposed cancellation within 60 days of the original due date of the form C-115, the division may cancel the operator's authority to transport from or inject into all wells it operates.
[19.15.7.24 NMAC - Rp, 19.15.13.1115 NMAC, 12/1/2008; A, 11/14/2017]

19.15.7.25 VENTED AND FLARED NATURAL GAS (Form C-115B):

Commented [SR2]: We recommend C-115B reporting only apply to midstream per 19.15.28.22.C(7). The vented and flared volumes for upstream can continue to be reported on C-115 with clearly defined categories to report within the rule.

A. An operator shall file form C-115B in accordance with 19.15.27 NMAC and 19.15.28 NMAC.

B. An operator shall file form C-115B using the division's web-based online application on or before the 15th day of the second month following the month in which venting or flaring occurred, or if such day falls on a weekend or holiday, the first workday following the 15th. ~~no later than the 30th day of the month following the month in which venting or flaring occurred~~. An operator may apply to the division for exemption from the electronic filing requirement based upon a demonstration that such requirement would be an economic or other hardship.

Commented [SR3]: We recommend keeping the current requirement for filing C-115s.

[19.15.7 NMAC – X, xx/xx/xxxx]

19.15.7.26 GAS-OIL RATIO TESTS (Form C-116): An operator shall make and report gas-oil ratio tests on form C-116 as prescribed in 19.15.18.8 NMAC and applicable special pool orders. The operator shall file the form C-116.
[19.15.7.25 NMAC - Rp, 19.15.13.1116 NMAC, 12/1/2008]

19.15.7.27 TANK CLEANING, SEDIMENT OIL REMOVAL, TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS AND DISPOSAL PERMIT (Form C-117-A) AND MONTHLY SEDIMENT OIL DISPOSAL STATEMENT (Form C-117-B):

A. An operator shall file form C-117-A with the appropriate division district office in accordance with Subsections B, C and H of 19.15.18.17 NMAC.

B. An operator shall file form C-117-B with the division's Santa Fe office and the appropriate division district office in accordance with Subsection D of 19.15.18.17 NMAC.
[19.15.7.26 NMAC - Rp, 19.15.13.1117 NMAC, 12/1/2008]

19.15.7.28 TREATING PLANT OPERATOR'S MONTHLY REPORT (Form C-118): A treating plant operator shall file on a monthly basis form C-118 with the appropriate division district office. The form C-118 shall contain all the information the form requires. Column 1 of sheet 1-A of form C-118 entitled permit number, references form C-117-A, for each lot of oil the operator picked up for processing.
[19.15.7.27 NMAC - Rp, 19.15.13.1118 NMAC, 12/1/2008]

19.15.7.29 MONTHLY WATER DISPOSAL REPORT (Form C-120-A): An operator of a salt water disposal system shall report its operations on form C-120-A. The operator shall file form C-120-A in duplicate, with one copy to the division's Santa Fe office and one copy to the appropriate division district office, and shall postmark the form no later than the 15th day of the second succeeding month.
[19.15.7.28 NMAC - Rp, 19.15.13.1120 NMAC, 12/1/2008]

19.15.7.39 PURCHASER'S NOMINATION FORMS (Form C-121 and Form C-121-A):

A. Unless the director requests otherwise, a person expecting to purchase oil from producing wells in New Mexico during the second and third succeeding two months shall file form C-121 with the division's Santa Fe office not later than the 20th day of each odd-numbered month. As an example, nominations submitted by the 20th day of July shall indicate the amount of oil the purchaser desires to purchase daily during September and October

B. The person shall file form C-121-A with the division's Santa Fe office by the first day of the month during which the division will consider at the gas allowable hearing the nominations for the purchase of gas from producing wells in New Mexico during the succeeding month. As an example, purchaser's nominations to take gas from a pool during the month of August would be considered by the division at a hearing during July, and should be submitted to the Santa Fe office of the division by July 1.

C. In addition to the monthly gas nominations, the purchaser shall file 12-month nominations in accordance with the appropriate special pool orders.
[19.15.7.29 NMAC - Rp, 19.15.13.1121 NMAC, 12/1/2008]

19.15.7.31 MULTIPOINT AND ONE POINT BACK PRESSURE TEST FOR GAS WELL (Form C-122):

A. Gas well test data sheet - San Juan basin (form C-122-A)

B. Initial potential test data sheet (form C-122-B)

C. Deliverability test report (form C-122-C)

D. Worksheet for calculation of static column wellhead pressure (P_w) (form C- 122-D)

E. Worksheet for stepwise calculation of (surface) (subsurface) pressure (P_c & P_w) (P_f & P_s) (form C-122-E)

F. Worksheet for calculation of wellhead pressures (P_c or P_w) from known bottom hole pressure (P_f or P_s) (form C-122-F)

G. Worksheet for calculation of status column pressure at gas liquid interface (form C-122-G). The operator shall file the forms listed in Subsections A through F of 19.15.7.30 NMAC with the appropriate division district office in accordance with the provisions of the *manual for back-pressure testing of natural gas wells or gas well testing manual for northwest New Mexico*, 19.15.19.8 NMAC and applicable special pool orders and proration orders.
[19.15.7.30 NMAC - Rp, 19.15.13.1122 NMAC, 12/1/2008]

19.15.7.32 REQUEST FOR THE CREATION OF A NEW POOL (Form C-123): The appropriate division district office shall provide the operator of a well that requires the creation of a pool written instructions regarding the filing of form C-123.

[19.15.7.31 NMAC - Rp, 19.15.13.1123 NMAC, 12/1/2008]

19.15.7.33 RESERVOIR PRESSURE REPORT (Form C-124):

A. An operator shall file form C-124 to report bottom hole pressures as required under the provisions of 19.15.18.9 NMAC and applicable special pool orders.

B. An operator shall state the name of the pool; the pool datum, if established; the name of the operator and lease; the well number; the wellhead elevation above sea level; the date of the test; the total time the well was shut in prior to the test, the subsurface temperature in degrees fahrenheit at the test depth; the depth in feet at which the operator made the subsurface pressure test; the observed pressure in psi gauge corrected for calibration and temperature; the corrected pressure computed from applying to the observed pressure the appropriate correction for difference in test depth and reservoir datum plane; and any other information required on form C-124.

[19.15.7.32 NMAC - Rp, 19.15.13.1124 NMAC and 19.15.5.302 NMAC, 12/1/2008]

19.15.7.34 GAS WELL SHUT-IN PRESSURE TESTS (Form C-125): An operator shall file form C-125 to report shut-in pressure tests on gas wells as required under the provisions of special pool orders.

[19.15.7.33 NMAC - Rp, 19.15.13.1125 NMAC, 12/1/2008]

19.15.7.35 PERMIT TO TRANSPORT RECOVERED LOAD OIL (Form C-126): An applicant to transport recovered load oil shall file form C-126 with the appropriate division district office in conformance with 19.15.20.15 NMAC.

[19.15.7.34 NMAC - Rp, 19.15.13.1126 NMAC, 12/1/2008]

19.15.7.36 REQUEST FOR ALLOWABLE CHANGE (Form C-127): An oil producer shall file form C-127 with the appropriate division district office not later than the 10th day of the month preceding the month for which an oil producer is requesting oil well allowable changes.

[19.15.7.35 NMAC - Rp, 19.15.13.1127 NMAC, 12/1/2008]

19.15.7.37 FORMS REQUIRED ON FEDERAL LAND:

A. An operator shall use federal forms in lieu of state forms when filing application for permit to drill, deepen or plug back and sundry notices and reports on wells and well completion or recompletion report and log for wells on federal lands in New Mexico. However, the operator shall submit two extra copies of each of the forms to the BLM, which, upon approval, will transmit the forms to the division. An operator of a well on federal land shall use the following BLM forms in lieu of division forms:

BLM Form No.	Title of Form (Same for both agencies)	Form No.
3160-3 (Nov. 1993)	Application for Permit to Drill, Deepen or Plug Back	C-101
3160-5 (Nov. 1983)	Sundry Notices and Reports on Wells	C-103
3160-4 (Nov. 1983)	Well Completion or Recompletion Report and Log	C-105

B. The above forms as the BLM may revise are the only forms that an operator may file in place of division forms.

C. After a well is completed and ready for pipeline connection, the operator shall file form C-104 along with a copy of form C-105 or BLM form No. 3160-4, whichever is applicable, with the division on wells drilled in the state, regardless of land status. Further, the operator shall file production reports using division forms; the division will not accept federal forms for reporting production.

D. An operator's failure to comply with 19.15.7.36 NMAC shall result in the division's cancellation of form C-104 for the affected well or wells.
[19.15.7.36 NMAC - Rp, 19.15.13.1128 NMAC, 12/1/2008]

19.15.7.38 REPORT OF VENTED OR FLARED NATURAL GAS (Form C-129): An operator shall file form C-129 when applicable, in accordance with 19.15.27 NMAC and 19.15.28 NMAC.
[19.15.7.37 NMAC - Rp, 19.15.13.1129 NMAC, 12/1/2008]

19.15.7.39 NOTICE OF DISCONNECTION (Form C-130):

A. An operator shall file form C-130 with the division as provided in 19.15.19.13 NMAC.

B. An operator shall state to the best of its knowledge the reasons for disconnecting a gas well from gas transportation facilities.

C. The division shall furnish the New Mexico public regulation commission with a form C-130 indicating that a disconnected gas well may or will be reconnected to a gas transportation facility for ultimate distribution to consumers outside of the state.
[19.15.7.38 NMAC - Rp, 19.15.13.1130 NMAC, 12/1/2008]

19.15.7.40 MONTHLY GAS STORAGE REPORT (Form C-131-A); ANNUAL LPG STORAGE REPORT (Form C-131-B):

A. An operator of an underground gas storage project shall report its operation monthly on form C-131-A. The operator shall file form C-131-A with the division's Santa Fe office with a copy to the appropriate division district office and shall postmark it not later than the 24th day of the next succeeding month.

B. An operator of underground liquefied petroleum gas storage projects approved by the division shall report its operations annually on form C-131-B.
[19.15.7.39 NMAC - Rp, 19.15.13.1131 NMAC, 12/1/2008]

19.15.7.41 AUTHORIZATION TO MOVE PRODUCED WATER:

A. A transporter of produced water shall obtain the division's approval of form C-133 in accordance with 19.15.34 NMAC prior to transportation.

B. Approval of a single form C-133 is valid for leases the transporter serves.
[19.15.7.40 NMAC - Rp, 19.15.13.1133 NMAC, 12/1/2008]

19.15.7.42 GAS WELL CONNECTION, RECONNECTION OR DISCONNECTION NOTICE: A gas transporter accepting gas for delivery from a wellhead or central point of delivery shall notify the division within 30 days of a new connection or reconnection to or disconnection from the gathering or transportation system by filing form C-135 with the appropriate division district office.
[19.15.7.41 NMAC - Rp, 19.15.13.1135 NMAC, 12/1/2008]

19.15.7.43 APPLICATION FOR APPROVAL TO USE AN ALTERNATE GAS MEASUREMENT METHOD (Form C-136):

A. An operator shall use form C-136 to request and obtain division approval for use of an alternate procedure for measuring gas production from a well that is not capable of producing more than 15 MCFD (Paragraph (1) of Subsection B of 19.15.19.9 NMAC) or for a well that has a producing capacity of 100 MCFD or less and is on a multi-well lease (Paragraph (2) of Subsection B of 19.15.19.9 NMAC).

B. An operator shall fill out the applicable information required on form C-136 with the required supplemental information attached, and file it with the appropriate division district office.
[19.15.7.42 NMAC - Rp, 19.15.13.1136 NMAC, 12/1/2008]

19.15.7.44 APPLICATION FOR PRODUCTION RESTORATION PROJECT (C-139):

A. An operator shall use the division's web-based online application to apply for the production restoration tax incentive.

B. An operator shall enter a user identification number and password that it has obtained from the division and select the well for which the operator is requesting the production restoration tax incentive. The operator shall then enter the date it began the production restoration, the date the well returned to production and the process the operator used to return the well to production. The operator shall certify that the information is complete and correct.
[19.15.7.43 NMAC - Rp, Paragraph (5) of Subsection D of 19.15.1.31 NMAC, 12/1/2008]

19.15.7.45 APPLICATION FOR WELL WORKOVER PROJECT (C-140):

A. An operator shall use the division's web-based online application to apply for the well workover tax incentive.

B. An operator shall enter a user identification number and password that it has obtained from the division and select the well for which the operator is requesting the well workover tax incentive. The operator shall enter the date that it commenced the well workover and the date it completed the well workover. The operator shall attach a description of the workover procedure it performed to increase production and a production curve or data tabulation showing at least 12 months of production prior to the well workover and at least three months of production following the well workover to reflect a positive production increase.
[19.15.7.44 NMAC - Rp, Paragraph (6) of Subsection D of 19.15.1.32 NMAC, 12/1/2008]

HISTORY of 19.15.7 NMAC:

History of Repealed Material: 19.15.1 NMAC, General Provisions (filed 04/27/2001); 19.15.13 NMAC, Reports (filed 06/17/2004) and 19.15.15 NMAC, Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps (filed 5/30/2008) repealed 12/1/08.

NMAC History:
Those applicable portions of 19.15.1 NMAC, General Provisions (Sections 14, 16, those applicable portions of 31 and 32 (filed 04/27/2001); 19.15.13 NMAC, Reports (Sections 1-6; 1100, 1101-1109, 1111-1113; 1115-1118, 1120-1131; 1133; and 1135) (filed 06/17/2004); and 19.15.15 NMAC, Pits, Closed-Loop Systems, Below-Grade Tanks and Sumps (Section 1302) (filed 5/30/2008) were all replaced by 19.15.7 NMAC, Forms and Reports, effective 12/1/08.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 18 PRODUCTION OPERATING PRACTICES

19.15.18.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.18.1 NMAC - N, 12/1/2008]

19.15.18.2 SCOPE: 19.15.18 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.18.2 NMAC - N, 12/1/2008]

19.15.18.3 STATUTORY AUTHORITY: 19.15.18 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12, NMSA 1978.
[19.15.18.3 NMAC - N, 12/1/2008]

19.15.18.4 DURATION: Permanent.
[19.15.18.4 NMAC - N, 12/1/2008]

19.15.18.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.18.5 NMAC - N, 12/1/2008]

19.15.18.6 OBJECTIVE: To regulate the production of oil and gas wells within the state in order to prevent waste, protect correlative rights and protect public health and the environment.
[19.15.18.6 NMAC - N, 12/1/2008]

19.15.18.7 DEFINITIONS: "Drip" means a liquid hydrocarbon incidentally accumulating in a gas gathering or transportation system.
[19.15.2.7 NMAC - Rp, Subsection A of 19.15.5.314 NMAC, 12/1/2008]

19.15.18.8 GAS-OIL RATIO AND PRODUCTION TESTS:

A. An operator shall take a gas-oil ratio test no sooner than 20 days nor later than 30 days following the completion or recompletion of each oil well, if:

(1) the well is a wildcat, or

(2) the well is located in a pool that is not exempt from 19.15.18.8 NMAC's requirements.

B. Provisions of 19.15.18.8 NMAC that are applicable to the pool shall govern wells completed within one mile of the outer boundary of a defined oil pool producing from the same formation. The operator shall report the test results to the division on form C-116 within 10 days following the test's completion. The gas-oil ratio the operator reports shall become effective for proration purposes on the first day of the calendar month following the date they are reported.

C. Each operator shall take an annual gas-oil ratio test of each producing oil well, located within a pool not exempted from the requirements of 19.15.18.8 NMAC, during a period the division prescribes. The division shall establish a gas-oil ratio survey schedule setting forth the period in which operators are to take gas-oil ratio tests for each pool where the division requires a test. The gas-oil ratio test shall be a test the division designates, made by the method and in the manner the division in its discretion may prescribe from time to time.

D. An operator shall file the results of gas-oil ratio tests taken during survey periods with the division on form C-116 not later than the 10th of the month following the close of the survey period for the pool in which the well is located. The gas-oil ratios thus reported shall become effective for proration purposes on the first day of the second month following the survey period's close. Unless the operator files form C-116 within the required time limit, the division shall not assign a further allowable to the affected well until the operator file form C-116.

E. In the case of special tests taken between regular gas-oil ratio surveys, the gas-oil ratio becomes effective for proration purposes upon the date the division receives form C-116 reporting the test results. A special test does not exempt a well from the regular survey.

F. During a gas-oil ratio test, an operator shall not produce a well at a rate exceeding the top proration unit allowable for the pool in which it is located by more than twenty-five percent.

G. The director may exempt such pools as the director deems proper from the gas-oil ratio test requirements of 19.15.18.8 NMAC. The exemption shall be by division order directed to the operators in the pool being exempted.

H. The director may require annual productivity tests of oil wells in pools exempt from gas-oil ratio tests, during a period the division prescribes. The division shall establish an oil well productivity survey schedule setting forth the period in which productivity tests are to be taken for each pool where the division requires the tests.

I. An operator shall file the results of productivity tests taken during survey periods with the division on form C-116 (with the word "exempt" inserted in the column normally used for reporting gas production) not later than the 10th of the month following the close of the survey period for the pool in which the well is located. Unless the operator files form C-116 within the required time limit, the division shall not assign further allowables to the affected well until the operator files form C-116.

J. In the case of special productivity tests taken between regular test survey periods, which result in a change of allowable assigned to the well, the allowable change shall become effective upon the date the division receives form C-116. A special test does not exempt a well from the regular survey.

K. During the productivity test, an operator shall not produce a well at a rate exceeding the top proration unit allowable for the pool in which it is located by more than twenty-five percent.
[19.15.18.8 NMAC - Rp, 19.15.5.301 NMAC, 12/1/2008]

19.15.18.9 BOTTOM HOLE PRESSURE TESTS: The operator shall make a bottom hole pressure test on the discovery well of a new pool and shall report the results of the test to the division within 30 days after the discovery well's completion. On or before December 1 of each calendar year the division shall designate the months in which operators shall take bottom hole pressure tests in designated pools. The division shall include in the designated list the required shut-in pressure time and datum of tests to be taken in each pool. In the event a newly discovered pool is not included in the division's list, the division shall issue a supplementary bottom hole pressure schedule. Tests the division designates shall only apply to flowing wells in each pool. A person qualified by both training and experience to make such test shall make the test with an approved bottom hole pressure instrument that is calibrated against an approved dead-weight tester at intervals frequent enough to ensure its accuracy within one percent. Unless the division otherwise designates, all wells shall remain completely shut in for at least 24 hours prior to the test. In the event the division does not establish a definite datum the operator shall obtain the bottom hole determination as close as possible to the mid-point of the reservoir's productive sand. The operator shall report the test results to the division on form C-124, which shall contain the information required by Subsection B of 19.15.7.32 NMAC.
[19.15.18.9 NMAC - Rp, 19.15.5.302 NMAC, 12/1/2008]

19.15.18.10 CONTROL OF MULTIPLE COMPLETED WELLS: The operator shall at all times operate, produce and maintain multiple completed wells that the division has authorized in a manner to ensure the complete segregation of the various common sources of supply. The division may require the operator take tests the division deems necessary to determine the effectiveness of segregation of the different common sources of supply.
[19.15.18.10 NMAC - Rp, 19.15.5.304 NMAC, 12/1/2008]

19.15.18.11 [RESERVED]
19.15.18.12 [RESERVED]
19.15.18.12 OPERATION AT BELOW ATMOSPHERIC PRESSURE:

A. An operator may use vacuum pumps, gathering system compressors or other devices to operate a well or gathering system at below atmospheric pressure only if that operator has:

(1) executed a written agreement with the operator of the downstream gathering system or pipeline to which the well or gathering system so operated is immediately connected allowing operation of the well or gathering system at below atmospheric pressure; and

(2) filed a sundry notice in the appropriate division district office for each well operated at below atmospheric pressure or served by a gathering system operated at below atmospheric pressure, within 90 days before beginning operation at below atmospheric pressure, notifying the division that the well or gathering system serving the well is being operated at below atmospheric pressure.

B. A gathering system operator may use vacuum pumps, gathering system compressors or other devices to operate a gathering system at below atmospheric pressure, or may accept gas originating from a well operated at below atmospheric pressure or that has been carried by an upstream gathering system operated at below atmospheric pressure, only if that operator has executed a written agreement with the operator of the downstream gathering system or pipeline to which the gathering system is immediately connected allowing delivery of gas from a well or gathering system that has been operated at below atmospheric pressure into the downstream gathering system or pipeline.
[19.15.18.13 NMAC - Rp, 19.15.5.307 NMAC, 12/1/2008]

19.15.18.13 SALT OR SULPHUR WATER: An operator shall report monthly on form C-115 the amount of water produced with the oil and gas from each well.
[19.15.18.14 NMAC - Rp, 19.15.5.308 NMAC, 12/1/2008]

19.15.18.14 AUTOMATIC CUSTODY TRANSFER EQUIPMENT:

A. Oil shall be received and measured in facilities of an approved design. The facilities shall permit the testing of each well at reasonable intervals and may be comprised of manually gauged, closed stock tanks for which the operator of the ACT system has prepared proper strapping tables, or of ACT equipment. The division shall permit ACT equipment's use only after the operator complies with the following. The operator shall file with the division form C-106 and receive approval for use of the ACT equipment prior to transferring oil through the ACT system. The carrier shall not accept delivery of oil through the ACT system until the division has approved form C-106.

B. The operator of the ACT system shall submit form C-106 to the appropriate division district office, which is accompanied by the following:

(1) plat of the lease showing all wells that the any well operator will produce into the ACT system;

(2) schematic diagram of the ACT equipment, showing on the diagram all major components such as surge tanks and their capacity, extra storage tanks and their capacity, transfer pumps, monitors, reroute valves, treaters, samplers, strainers, air and gas eliminators, back pressure valves and metering devices (indicating type and capacity, *i.e.* whether automatic measuring tank, positive volume metering chamber, weir-type measuring vessel or positive displacement meter); the schematic diagram shall also show means employed to prove the measuring device's accuracy; and

(3) letter from transporter agreeing to utilization of ACT system as shown on schematic diagram.

C. The division shall not approve form C-106 unless the operator of the ACT system will install and operate the ACT system in compliance with the following requirements.

(1) Provision is made for accurate determination and recording of uncorrected volume and applicable temperature, or of temperature corrected volume. The system's overall accuracy shall equal or surpass manual methods.

(2) Provision is made for representative sampling of the oil transferred for determination of API gravity and BS&W content.

(3) Provision is made if required by either the oil's producer or the transporter to give adequate assurance that the ACT system runs only merchantable oil.

(4) Provision is made for set-stop counters to stop the flow of oil through the ACT system at or prior to the time the allowable has been run. Counters shall provide non-reset totalizers that are visible for inspection at all times.

(5) Necessary controls and equipment are enclosed and sealed, or otherwise arranged to provide assurance against, or evidence of, accidental or purposeful mismeasurement resulting from tampering.

(6) The ACT system's components are properly sized to ensure operation within the range of their established ratings. All system components that require periodic calibration or inspection for proof of continued accuracy are readily accessible; the frequency and methods of the calibration or inspection shall be as set forth in Paragraph (12) of Subsection C of 19.15.18.15 NMAC.

(7) The control and recording system includes adequate fail-safe features that provide assurance against mismeasurement in the event of power failure, or the failure of the ACT system's component parts.

(8) The ACT system and allied facilities include fail-safe equipment as may be necessary, including high level switches in the surge tank or overflow storage tank that, in the event of power failure or malfunction of the ACT or other equipment, will shut down artificially lifted wells connected to the ACT system and will shut in flowing wells at the well-head or at the header manifold, in which latter case the operator of the ACT system shall pressure test all flowlines to at least 1½ times the maximum well-head shut-in pressure prior to the ACT system's initial use and every two years thereafter.

(9) As an alternative to the requirements of Paragraph (8) of Subsection C of 19.15.18.15 NMAC the producer shall provide and at all times maintain a minimum of available storage capacity above the normal high working level of the surge tank to receive and hold the amount of oil that may be produced during maximum unattended time of lease operation.

(10) In all ACT systems employing automatic measuring tanks, weir-type measuring vessels, positive volume metering chambers or any other volume measuring container, the container and allied components shall be properly calibrated prior to initial use and shall be operated, maintained and inspected as necessary to ensure against incrustation, changes in clingage factors, valve leakage or other leakage and improper action of floats, level detectors, etc.

(11) In ACT systems employing positive displacement meters, the meter and allied components shall be properly calibrated prior to initial use and shall be operated, maintained and inspected as necessary to ensure against oil mismeasurement.

(12) The operator of the ACT system shall check the measuring and recording devices of ACT systems for accuracy at least once each month unless it has obtained an exception to such determination from the division. Where applicable, the operator of the ACT system shall use API standard 1101, Measurement of Petroleum Hydrocarbons by Positive Displacement Meter. Meters may be proved against master meters, portable prover tanks or prover tanks permanently installed on the lease. If the operator of the ACT system uses permanently installed prover tanks, the distance between the opening and closing levels and the provision for determining the opening and closing readings shall be sufficient to detect variations of 5/100 of one percent. The operator of the ACT system shall file reports of determination on the division form entitled "meter test report" or on another acceptable form in duplicate with the appropriate division district office.

(13) To obtain an exception to the requirement in Paragraph (12) of Subsection C of 19.15.18.15 NMAC that all measuring and recording devices be checked for accuracy once each month, either the producer or transporter may file a request with the director setting forth facts pertinent to the exception. The application shall include a history of the average factors previously obtained, both tabulated and plotted on a graph of factors versus time, showing that the particular installation has experienced no erratic drift. The applicant shall also furnish evidence that the other interested party has agreed to the exception. The director may then set the frequency for determination of the system's accuracy at the interval which the director deems prudent.

D. The division may revoke its approval of an ACT system's form C-106 if the system's operator fails to operate it in compliance with 19.15.18.15 NMAC.

[19.15.18.15 NMAC - Rp, 19.15.5.309 NMAC, 12/1/2008]

19.15.18.15 TANKS, OIL TANKS, FIRE WALLS AND TANK IDENTIFICATION:

A. No person shall store or retain oil in earthen reservoirs or in open receptacles. Dikes or fire walls are not required except an operator shall erect and maintain fire walls around permanent oil tanks or tank batteries that are within the corporate limits of a city, town or village, or where such tanks are closer than 150 feet to a producing oil or gas well or 500 feet to a highway or inhabited dwelling or closer than 1000 feet to a school or church, or where the tanks are so located that the division deems them an objectional hazard. Where fire walls are required, fire walls shall form a reservoir having a capacity one-third larger than the capacity of the enclosed tank or tanks.

B. The operator shall identify oil tanks, tank batteries, ACT systems, tanks used for salt water collection or disposal and tanks used for sediment oil treatment or storage by a sign posted on or not more than 50 feet from the tank, tank battery or system. The sign shall be of durable construction and the operator shall keep the lettering on the sign in a legible condition; the lettering shall be large enough to be legible under normal conditions at a distance of 50 feet and the sign shall identify the operator's name, the name of the lease being served by the tank or system, if any, and the location of the tank or system by unit letter, section, township and range.

[19.15.18.16 NMAC - Rp, 19.15.5.310 NMAC, 12/1/2008]

19.15.18.16 SEDIMENT OIL, TANK CLEANING AND TRANSPORTATION OF MISCELLANEOUS HYDROCARBONS:

A. No person shall clean a tank of sediment oil or remove sediment oil from a lease without the appropriate division district office's prior approval. The lease operator or the company contracted or otherwise authorized to perform the tank cleaning may receive authorization for tank

cleaning by obtaining division approval on form C-117-A. No operator, contractor or other party shall clean a tank of sediment oil or remove sediment oil from a lease without an approved copy of form C-117-A at the site.

B. No person shall destroy sediment oil without the appropriate division district office's approval of an application to destroy the sediment oil on form C-117-A. Unless a person receiving an authorization to destroy sediment oil utilizes the authorization to destroy sediment oil within 10 days after division approval of the form C-117-A the authorization is automatically revoked. However, the district supervisor may approve one 10 day extension for good cause shown.

C. A person, other than a treating plant operator, who cleans a tank of sediment oil and removes sediment oil from a lease shall file form C-117-B with the division setting out all information the form requires.

D. A person taking possession of or disposing of sediment oil shall test a representative sample of sediment oil in a manner designed to accurately estimate the percentage of good oil expected to be recovered from the sediment oil. The person shall perform the test prior to transport and prior to commingling with sediment oil from other leases or sources and record the results on form C-117-A. The division recommends the standard centrifugal tests prescribed by API publication Sediment and Water, Sect: 4: Determination of Sediment and Water in Crude Oil by the Centrifuge Method (Field Procedure), MPMS 10.4. The person may use other test procedures if the procedures reliably predict the percentage of good oil to be recovered from sediment oil.

E. A person taking possession of or disposing of sediment oil shall report sediment oil removed from storage on form C-115 together with the form C-117-A permit number.

F. Except in an emergency, no person shall deliver miscellaneous hydrocarbons to a treating plant or other facility until that person has obtained division approval on form C-117-A.

G. Whenever an emergency exists that requires delivery of miscellaneous hydrocarbons to a treating plant or other facilities prior to approval of form C-117-A, the transporter of the hydrocarbons shall notify the supervisor of the appropriate division district office of the emergency's nature and extent on the first working day following the emergency and shall file form C-117-A within two working days following the emergency. For prolonged emergencies, the district supervisor may authorize the extended movement of miscellaneous hydrocarbons to a treating plant or other facilities during the emergency period and shall approve a form C-117-A filed subsequent to the emergency's conclusion covering the entire volume of miscellaneous hydrocarbons transported.
[19.15.18.17 NMAC - Rp, 19.15.5.311 NMAC, 12/1/2008]

19.15.18.17 EMULSION, BASIC SEDIMENTS AND TANK BOTTOMS: The operator shall operate wells producing oil in a manner that reduces as much as practicable the formation of emulsion and basic sediments. No person shall allow these substances and tank bottoms to pollute fresh waters or cause surface damage.
[19.15.18.18 NMAC - Rp, 19.15.5.313 NMAC, 12/1/2008]

19.15.18.18 GATHERING, TRANSPORTING AND SALE OF DRIP:

A. The waste of drip is prohibited when it is economically feasible to salvage the drip.

B. A person may move and sell drip, provided it complies with 19.15.18.19 NMAC.

C. A person shall not transport or sell drip until the gas transporter files form C-104 designating the drip transporter authorized to remove the drip from its gas gathering or transportation system.

D. Each month, a person transporting drip within the state shall complete and maintain for division inspection form C-112, showing the amount, source and disposition of drip handled during the reporting period, and such other reports as the division may require.

E. Prior to commencement of operations, every person transporting drip directly from a gas gathering or transportation system shall file with the division plats drawn to scale, locating and identifying each drip trap that the person is authorized to service.

F. A person transporting drip directly from a gas gathering or transportation system shall keep a record of daily acquisitions from each drip trap that the person is authorized to service and make the records available at all reasonable times for inspection by the division or its authorized representatives.

G. A gas transporter shall, on or before the first day of November of each year, file with the division maps of its entire gas gathering and transportation systems, locating and identifying on the map each drip trap in the systems, the maps to be accompanied by a report, on a division-prescribed form, showing the disposition being made of the drip from each of the drip traps.
[19.15.18.19 NMAC - Rp, 19.15.5.314 NMAC, 12/1/2008]

HISTORY of 19.15.18 NMAC:

History of Repealed Material: 19.15.5 NMAC, Oil Production Operating Practices (filed 04/27/2000) repealed 12/1/2008.

NMAC History:
Those applicable portions of 19.15.5 NMAC, Oil Production Operating Practices Sections 301, 302, 304 - 311, 313 & 314) (filed 04/27/2000) were replaced by 19.15.18 NMAC, Production Operating Practices, effective 12/1/2008.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 19 NATURAL GAS PRODUCTION OPERATING PRACTICE

19.15.19.1 ISSUING AGENCY: Energy, Minerals and Natural Resources Department, Oil Conservation Division.
[19.15.19.1 NMAC - Rp, 19.15.6.1 NMAC, 12/1/2008]

19.15.19.2 SCOPE: 19.15.19 NMAC applies to persons engaged in gas development and production within New Mexico.
[19.15.19.2 NMAC - Rp, 19.15.6.2 NMAC, 12/1/2008]

19.15.19.3 STATUTORY AUTHORITY: 19.15.19 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12, NMSA 1978.
[19.15.19.3 NMAC - Rp, 19.15.6.3 NMAC, 12/1/2008]

19.15.19.4 DURATION: Permanent.
[19.15.19.4 NMAC - Rp, 19.15.6.4 NMAC, 12/1/2008]

19.15.19.5 EFFECTIVE DATE: December 1, 2008, unless a later date is cited at the end of a section.
[19.15.19.5 NMAC - Rp, 19.15.6.5 NMAC, 12/1/2008]

19.15.19.6 OBJECTIVE: To regulate the gas production within the state in order to prevent waste, protect correlative rights and protect public health and the environment.
[19.15.19.6 NMAC - Rp, 19.15.6.6 NMAC, 12/1/2008]

19.15.19.7 DEFINITIONS: [RESERVED]
[See 19.15.2.7 NMAC for definitions.]

19.15.19.8 METHOD OF DETERMINING GAS WELL POTENTIAL:

A. An operator shall conduct tests to determine the daily open flow potential volumes of gas wells from which gas is being used or marketed. The operator shall report the tests on division-prescribed forms within 60 days after

(1) the date of the well's initial connection to a gas transportation facility; and

(2) the date of reconnection following workover.

B. To establish comparable open flow capacity, the operator shall test wells in accordance with the division's Manual for back-pressure testing of natural gas wells. If the division approves the alternate method for testing, the operator shall test all wells producing from a common source of supply in a uniform and comparable manner.

C. The operator of a gas well that is not connected to a gas gathering facility shall test the well within 30 days following a christmas tree's installation. The operator shall take the tests in accordance with the procedure for testing unconnected gas well contained in the division's *manual for back-pressure testing of natural gas wells*. The operator shall report the tests on form C-122 in compliance with 19.15.7.31 NMAC and file it within 10 days following the test's completion.
[19.15.19.8 NMAC - Rp, 19.15.6.401 NMAC, 12/1/2008]

19.15.19.9 GAS FROM GAS WELLS TO BE MEASURED:

A. The transporter of gas produced shall account for the gas by metering or other division-approved method and report it to the division. The owner or operator of the gas transportation facility shall report gas produced from a gas well and delivered to a gas transportation facility. The well operator shall report gas produced from a gas well and required to be reported by 19.15.19.9 NMAC that is not delivered to and reported by a gas transportation facility.

B. An operator may apply to the district supervisor, using form C-136, for approval of one of the following procedures for measuring gas.

(1) In the event a well is not capable of producing more than 15 MCFD, a measurement method agreed upon by the operator and transporter whereby the parties establish by annual test the producing rate of the well under normal operating conditions and apply that rate to the period of time the well is in a producing status. If the well is capable of producing greater than five MCFD, the transporter shall attach a device to the line that determines the actual time period that the well is flowing.

(2) An operator may produce a well that has a producing capacity of 100 MCFD or less and that is on a multi-well lease without the well being separately metered when the gas is measured using a lease meter at a CPD. The lease's ownership shall be common throughout including working interest, royalty and overriding royalty ownership.

(3) If normal operating conditions change, either party may request a new well test, the cost of which the party requesting the new well test shall bear unless the parties otherwise agree.

C. The operator and transporter shall report the well volumes on forms C-115 and C-111 based upon the approved method of measurement and, in the case of a CPD, upon the method of allocation of production to individual wells the district supervisor approves.
[19.15.19.9 NMAC - Rp, 19.15.6.403 NMAC, 12/1/2008]

[RESERVED]

19.15.19.11 STORAGE GAS: With the exception of the requirement to meter and report monthly the amount of gas injected and the amount of gas withdrawn from storage, in the absence of waste 19.15.19 NMAC shall not apply to gas being injected into or removed from storage. (See 19.15.7.40 NMAC)
[19.15.19.11 NMAC - Rp, 19.15.6.405 NMAC, 12/1/2008]

19.15.19.12 CARBON DIOXIDE: The rules relating to gas, gas wells and gas reservoirs including those provisions relating to well locations, acreage dedication requirements, casing and cementing requirements and measuring and reporting of production also apply to carbon dioxide gas, carbon dioxide wells and carbon dioxide reservoirs.
[19.15.19.12 NMAC - Rp, 19.15.6.406 NMAC, 12/1/2008]

19.15.19.13 DISCONNECTION OF GAS WELLS: The operator shall report gas wells that are disconnected from intrastate gas transportation facilities to the division within 30 days of the date of disconnection. The operator shall file the notice on form C-130 in compliance with 19.15.7.39 NMAC.
[19.15.19.13 NMAC - Rp, 19.15.6.407 NMAC, 12/1/2008]

HISTORY of 19.15.19 NMAC:

History of Repealed Material: 19.15.6 NMAC, Natural Gas Production Operating Practice (filed 11/29/2001) repealed 12/1/2008.

NMAC History:
Those applicable portions of 19.15.6 NMAC, Natural Gas Production Operating Practice (Sections 401, and 403 - 407) (filed 11/29/2001) were replaced by 19.15.19 NMAC, Natural Gas Production Operating Practice, effective 12/1/2008.

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AN GAS
PART 27 VENTING AND FLARING OF NATURAL GAS

19.15.27.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.27.1 NMAC – N, xx/xx/xx]

19.15.27.2 SCOPE: 19.15.27 NMAC applies to persons engaged in oil and gas development and production within New Mexico.
[19.15.27.2 NMAC – N, xx/xx/xx]

19.15.27.3 STATUTORY AUTHORITY: 19.15.27 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12 NMSA 1978.
[19.15.27.3 NMAC – N, xx/xx/xx]

19.15.27.4 DURATION: Permanent.
[19.15.27.4 NMAC – N, xx/xx/xx]

19.15.27.5 EFFECTIVE DATE: [DATE], unless a later date is cited at the end of a section.
[19.15.27.5 NMAC – N, xx/xx/xx]

19.15.27.6 OBJECTIVE: To regulate the venting and flaring of natural gas from wells and production equipment and facilities to prevent waste and protect correlative rights, public health and the environment.
[19.15.27.6 NMAC – N, xx/xx/xx]

19.15.27.7 DEFINITIONS: Definitions shall have the meaning specified in 19.15.2 NMAC except as specified below.

A. "Air Pollution Control Equipment" means air pollution control equipment as defined by the New Mexico Environment Department.

B. "ALARM" means advanced leak and repair monitoring systems designed to detect and identify methane emissions, which may include, but are not limited to, remote leak detection systems, fly over surveys, well monitoring systems approved by the New Mexico Environment Department, and other advanced leak detection technology.

C. "Average daily production" has the same meaning as in Subsection A of 19.15.6.7 NMAC.

D. "AVO" means audio, visual and ~~or~~ olfactory, which may include, but is not limited to, ALARM systems, remote leak detection, and well monitoring systems approved by the New Mexico Environment Department or the Division.

E. "Beneficial use" means the right to use oil, natural gas, or water for any and all rights and privileges necessary, incident to or convenient for operations permitted under an oil and gas lease, communitization agreement, or unit agreement.

F. "Completion operations" means the period that begins with the initial perforation of the well in the completed interval and concludes on the earlier of 30 days after

Commented [SR4]: Has the agency looked at how its orders (i.e., pooling order) reference the term completion or completions to see if there are any unintended consequences related to defining this term in the regulations? Stated another way, has the division determined if this definition will change or alter the deadlines for such operations contemplated under already issued orders?

commencement of initial flowback or when permanent production equipment is in use at the well.

G. **"Drilling ~~operations~~"** means the period that begins when a well is spud and concludes when casing and cementing has been completed and casing slips have been set to install tubing head in the well.

H. **"Emergency"** means a temporary, infrequent and unavoidable event in which the loss of natural gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health or the environment. An emergency is limited to a period not to exceed 24 hours, unless the division determines that conditions exist necessitating venting or flaring for a longer period, is caused by an unanticipated event or failure that is out of the operator's control and was not due to operator negligence. An emergency ~~but~~ does not include an event arising from or related to:

(1) the operator's failure to install appropriate equipment of sufficient capacity to accommodate the anticipated or actual rate and pressure of production;

(2) the operator's failure to limit production from a gas well when the production rate exceeds the capacity of the related equipment or natural gas gathering system as defined in 19.15.28 NMAC, or exceeds the sales contract volume of natural gas;

(3) scheduled maintenance;

(4) the operator's negligence, including a recurring equipment failure; or

(5) more than three failures of the same component within a single piece of equipment with 365 days. ~~two or more emergencies experienced by the operator within the preceding 60 days, unless the division determines the operator could not have reasonably anticipated the current event and it was beyond the operator's control~~.

~~**G.** **"Flare stack"** means an appropriately designed stack equipped with a burner used for the combustion and disposal of natural gas.~~

I. **"Flare" or "Flaring"** means the controlled combustion of natural gas in a device designed for that purpose.

J. **"Gas-to-oil ratio (GOR)"** for purposes of 19.15.27 NMAC means the ratio of natural gas to oil in the production stream expressed in standard cubic feet of natural gas per barrel of oil.

K. **"Initial flowback"** means the period during a well completion operation~~s~~ which begins at the onset of flowback and concludes when the well is plugged and abandoned. ~~that begins with the onset of flowback and concludes when it is technically feasible for a separator to function.~~

L. **"Malfunction"** means any sudden failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. ~~means a sudden, unavoidable failure or breakdown of equipment beyond the reasonable control of the operator that substantially disrupts operations and requires correction, but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation or other preventable equipment failure or breakdown.~~

~~**L.** **"N_2"** means nitrogen gas.~~

Commented [SR5]: The New Mexico Supreme Court has embraced a different definition of the term "drilling operations" in the context of leasehold and JOA interpretation disputes.

Commented [SR6]: To align with common utilization of the term "flare" or "flaring" would not include things such as a gas combustor which would meet the definition here. For sake of clarity would suggest utilizing air pollution control equipment and deleting this definition.

M. **"Natural gas"** means a salable gaseous mixture of hydrocarbon compounds, primarily composed of methane, and includes both casinghead gas and gas as defined in 19.15.2 NMAC.

N. **"Production operations"** means the period that begins on the earlier of 31 days following the commencement of initial flowback and concludes when the well is plugged and abandoned. ~~or when permanent production equipment is in use at a well and concludes when the well is plugged and abandoned.~~

O. **"Separation flowback"** means the period during completion operations that begins when it is technically feasible for a temporary separator to function and concludes on the earlier of 30 days after initial flowback begins or when permanent production equipment is in use at the well or production facility.

P. **"Vent" or "Venting"** means the release of uncombusted salable natural gas to the atmosphere but does not include equipment leaks regulated by the New Mexico Environment Department.

[19.15.27.7 NMAC – N, xx/xx/xx]

19.15.27.8 VENTING AND FLARING OF NATURAL GAS:

A. Venting and flaring of natural gas during drilling, completion or production operations constitutes waste and is prohibited except as authorized below. An operator has a general duty to maximize the recovery of natural gas and to minimize the surface loss ~~release~~ of natural gas ~~to the atmosphere~~.

B. **Venting and flaring during drilling operations.**

(1) The operator shall capture or combust natural gas escaping from the well using best available control technologies.

(2) A flare stack shall be located at a minimum of 100 feet from the nearest surface hole location and shall be ~~enclosed and~~ equipped with an automatic ignition system or continuous pilot.

~~**(3)** In an emergency or malfunction, the operator may vent natural gas to avoid a risk of an immediate and substantial adverse impact on safety, public health or the environment. The operator shall~~

~~**(a)** notify the division of the venting or flaring as soon as possible by email, but no more than two hours following discovery of the emergency or malfunction;~~

~~**(b)** file a form C-129 no later than 24 hours after commencing to vent or flare pursuant to Subparagraph (4) of Subsection E of 19.15.27.8 NMAC;~~

~~**(c)** notify the division as soon as practicable after it stops venting or flaring; and~~

~~**(d)** comply with the applicable requirement to report a release pursuant to 19.15.29 NMAC.~~

C. **Venting and flaring during completion operations.**

(1) During initial flowback, the operator shall route flowback fluids into a completion or storage tank and commence operation of a separator as soon as it is technically feasible for a separator to function.

(2) During separation flowback, the operator shall capture and route recovered natural gas to a gas flowline or collection system, re-inject it into the well or it use on-site as a fuel source or for another purpose that a purchased fuel or raw material would serve.

Commented [SR7]: Alternatively, this could be defined as:

…the period of operation after drilling operations and completions operations (as defined) and ending when the well ceases to produce.

Commented [SR8]: Alternatively, this could be defined as:

…the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Commented [SR9]: Enclosed flare stack can be very dangerous in uncontrolled well conditions.

(3) The operator may route recovered natural gas to a flare if routing or using the natural gas as described in Subparagraph (2) of Paragraph C of 19.15.27.8 NMAC poses a risk to safe operation or personnel safety, provided that the flare is equipped with an automatic igniter or continuous pilot.

(4) The operator may vent natural gas only if capturing or flaring the natural gas poses a risk to safe operations or personnel safety, and venting is safer than capturing and flaring.

D. Venting and flaring during production operations.

(1) The operator shall not vent or flare natural gas except as authorized below in Subparagraph (2) of Subsection D of 19.15.27.8 NMAC.

(2) The operator may vent or flare natural gas

(a) to the extent authorized by a valid federally enforceable air quality permit issued by the environment department or the U.S. Environmental Protection Agency;

(b) during an emergency or malfunction~~, but only to avoid a risk of an immediate and substantial adverse impact on safety, public health or the environment~~;

(c) to unload or clean-up a well to atmospheric pressure,

(i) if the operator allows the well to vent only so long as necessary to achieve a stabilized rate and pressure;

(ii) for liquids unloading by manual purging, when the operator remains present on-site until the end of unloading, takes all reasonable actions to achieve a stabilized rate and pressure at the earliest practical time and takes all reasonable actions to minimize venting to the maximum extent practicable;

(iii) for a well equipped with a plunger lift system or an automated control system, when the operator optimizes the operation of the system to minimize the venting of natural gas; or

(iv) during downhole well maintenance, if and only when the operator uses a workover rig, swabbing rig, coiled tubing unit or similar specialty equipment, and minimizes the venting of natural gas to the extent consistent with safe operation and best management practices; and

(d) during the following activities to the extent authorized by applicable state or federal law regulating the emission of hydrocarbons and volatile organic compounds:

(i) gauging or sampling of a storage tank or other low-pressure production vessel;

(ii) loading out liquids from a storage tank or other low-pressure production vessel to a transport vehicle;

(iii) scheduled repair and maintenance, including blowing down and depressurizing production equipment to perform repair and maintenance;

(iv) normal operation of a gas-activated pneumatic controller or pump;

(v) normal operation of a storage tank or other low-pressure production vessel, but not including venting from a thief hatch that has not been fully and timely closed or from a seal that has not been maintained on an established schedule;

(vi) a bradenhead test;

(vii) a packer leakage test; or

(viii) a production test that does not exceed 24 hours unless the division requires or approves a longer test period.

(3) The operator shall conduct an AVO inspection on the frequency specified below to confirm that all production equipment is operating properly and there is no venting except as allowed by Paragraph (2) of Subsection D of 19.15.27.8 NMAC. The operator shall

(a) conduct the AVO inspection quarterly on all wells; and, ~~weekly during the first year of production;~~

~~**(b)** conduct the AVO inspection weekly on a well with an average daily production greater than 10 barrels of oil or 60,000 cubic feet of natural gas;~~

~~**(c)** conduct the AVO inspection once per calendar month, with at least 20 calendar days between inspections, on a well with an average daily production equal to or less than 10 barrels of oil or 60,000 cubic feet of natural gas; and~~

(b) make and keep a record of each AVO inspection for not less than five years and make such record available for inspection by the division upon request.

(4) For venting or flaring during an emergency or malfunction pursuant to Subparagraph (b) of Paragraph (2) of Subsection D of 19.15.27.8 NMAC, the operator shall

(a) notify the division's environmental bureau chief and the appropriate division district office verbally by the next business day of when the venting or flaring began; ~~of the venting or flaring by email as soon as possible, but no more than two hours following discovery of the venting or flaring~~;

(b) file a form C-129 the next business day after the cessation of the venting or flaring event; and, ~~no later than 24 hours after commencing to vent or flare;~~

~~**(c)** notify the division as soon as practicable after the cessation of venting and flaring; and~~

(c) If applicable, comply with the reporting ~~applicable~~ requirement in ~~to report a release pursuant to~~ 19.15.29 NMAC.

(5) Performance standards for separation, storage tank and flare equipment.

(a) The operator shall design a temporary or permanent separation or storage tank to minimize the natural gas flashing and vapor accumulation.

(b) The operator shall equip a permanent storage tank associated with production operations that is installed after {effective date of rule} with an automatic gauging system to reduce the venting of natural gas.

(c) The operator shall combust ~~all~~ natural gas in a flare stack designed for and operated at maximum efficiency.

(i) A flare stack installed after May 31, 2021 shall be equipped with an automatic ignitor or continuous pilot.

(ii) A flare stack installed before June 1, 2021 shall be retrofitted with an automatic ignitor or continuous pilot no later than 18 months after {effective date of rule}.

(iii) A flare stack located at a Stripper Well Facility as defined by the New Mexico Environment Department in 20.2.50.8 ~~well with an average daily production of equal to or less than 10 barrels of oil or 60,000 cubic feet of natural gas~~ shall be retrofitted with an automatic ignitor or continuous pilot if the flare stack is replaced after {effective date of the rule}.

(d) A flare stack located at a well spud after {effective date of rule} shall be adequately anchored and located at least 100 feet from the well and storage tanks.

(e) The operator shall inspect a flare stack at least once per quarter ~~week~~ to confirm that it is being properly maintained and operated in conformance with its design, and shall make and keep a record of each inspection for not less than five years and make such records available for inspection by the division upon request.

E. Measurement, estimation and reporting of vented and flared natural gas.

(1) The operator shall measure or estimate the volume of natural gas that is vented, flared or beneficially used during ~~drilling, completion and~~ production operations ~~regardless of the reason or authorization for such venting and flaring~~.

(a) The operator shall measure or estimate ~~install equipment to measure~~ the volume of vented and flared natural gas from a well authorized by an APD issued after May 31, 2021 that exceeds a Stripper Well Facility as defined by the New Mexico Environment Department in 20.2.50.8. ~~has an average daily production greater than 10 barrels of oil or 60,000 cubic feet of natural gas.~~

(b) Measurement equipment shall be designed in accordance with the accuracy ratings and design standards in 43 C.F.R. § 3175.20.

~~**(c)** Measurement equipment shall not be designed or equipped with a manifold that allows the diversion of natural gas around the metering element except for the sole purpose of inspecting and servicing the measurement equipment.~~

(c) For a well that does not require measurement equipment, the operator shall estimate the volume of vented and flared natural gas based on the result of an annual GOR test for that well reported on form C-116.

(d) The operator shall install additional measurement equipment whenever the division determines that the existing measurement equipment or GOR test is not sufficient to measure the volume of vented and flared natural gas.

(2) The operator shall report the lost natural gas for each month on a volumetric and percentage basis on form C-115~~B~~.

~~**(a)** To calculate the lost natural gas on a volumetric basis, the operator shall deduct the volume of natural gas sold, used for beneficial use, vented or flared during an emergency and not suitable for transportation, from the natural gas produced.~~

~~**(b)** To calculate the lost natural gas on a percentage basis, the operator shall add the volume of natural gas sold, used for beneficial use, vented or flared during an emergency and not suitable for transportation, and divide by sum by the total natural gas produced.~~

(3) The operator shall report the volume of vented and flared natural gas for each month in each category in this subparagraph on form C-115~~B~~, and state whether the reported volume was estimated or measured. The operator shall make and keep records of the measurements and estimates, including how the estimated volumes were calculated, for not less than five years and make such records available for inspection by the division upon request. The categories are identified in Appendix XXA.

~~**(a)** emergency;~~

~~**(b)** non-scheduled maintenance;~~

~~**(c)** equipment malfunction by operator;~~

~~**(d)** equipment malfunction by third party;~~

Commented [SR10]: Reconciled with AVO inspection recommendation.

Commented [SR11]: We feel the current reporting of vented and flared volumes on the C-115, with clearly defined consolidated categories within the rule, is better than introducing a new C-115B form. See consolidated category chart – Appendix XXA.

Commented [SR12]: See consolidated category chart – Appendix XXA.

~~**(e)** drilling operations;~~
~~**(f)** completion operations;~~
~~**(g)** routine equipment repair and maintenance, including blowdown and depressurization;~~
~~**(h)** routine downhole maintenance, including operation of workover rigs, swabbing rigs, coiled tubing units and similar specialty equipment;~~
~~**(i)** pilot gas for combustion devices;~~
~~**(j)** purge gas to test or fuel combustion devices;~~
~~**(k)** manual liquid unloading;~~
~~**(l)** bradenhead tests;~~
~~**(m)** packer leakage tests;~~
~~**(n)** uncontrolled storage tanks;~~
~~**(o)** insufficient pipeline availability or capacity;~~
~~**(p)** natural gas quality that is not suitable for transportation and processing because of a high percentage of N_2 or H_2S;~~
~~**(q)** venting in excess of the design specifications of pneumatic controllers and pumps as a result of malfunction or improper or infrequent maintenance;~~
~~**(r)** commencing on January 1, 2022, venting as a result of normal operation of pneumatic controllers and pumps, except that~~
~~**(i)** in November 2021, the operator shall report the volume of vented natural gas that it reported to a state or federal agency, as revised to include data from pneumatic controllers and pumps in use during 2021 that were not included in the 2020 report; and~~
~~**(ii)** an operator who vents or flares less than 500,000 cubic feet per year of natural gas is exempted from this subparagraph;~~
~~**(s)** thief hatches that are not properly closed or maintained; and~~
~~**(t)** other not described above.~~

(4) The operator shall comply with applicable requirement to report a release pursuant to 19.15.29 NMAC. If volume is less than 50 MCF, file a form C-129 within 15 days of the cessation of the event which would include duration, cause and actual volumes vented or flared. ~~notify the division of any period of venting and flaring that exceeds eight hours in any 24 hour period and of all venting or flaring attributed to emergency or malfunction of any duration by submitting a form C-129 no later than 24 hours after the commencement of venting and flaring.~~

(a) The operator's form C-129 shall provide and certify the accuracy of the following information:

(i) operator's name;
(ii) name and type of facility;
(iii) equipment involved;
(iv) representative compositional analysis of the vented and flared natural gas if the natural gas is vented or flared because the quality that is not suitable for transportation and processing because of a high percentage of N_2 or H_2S;
(v) date and time that venting or flaring occurred;
(vi) measured or estimated volume of vented or flared natural gas;

Commented [SR13]: Amend C-141 form to include duration and if volume released was vented or flared.

Commented [SR14]: Current lab facilities can't turn around such testing in a shorter time frame.

(vii) cause and nature of venting or flaring;

(viii) steps taken to limit the duration and magnitude of venting or flaring (if applicable); and

(ix) corrective actions taken to eliminate the cause and recurrence of venting or flaring (if applicable).

(b) At the division's request, the operator shall provide additional information by the specified date and a certification of the accuracy of the information.

~~**(5)** The operator shall report the vented and flared natural gas on a volumetric and percentage basis to all royalty owners in the mineral estate being produced by the well on a monthly basis, and keep such reports for not less than five years and make such records available for inspection by the division upon request.~~

~~**(6)** Upon the environment department's request, the operator shall promptly provide a copy of any form filed pursuant to 20.2.27 NMAC.~~

[19.15.27.8 NMAC – N, xx/xx/xx]

19.15.27.9 STATEWIDE NATURAL GAS CAPTURE REQUIREMENTS:

A. Statewide natural gas capture requirements. Commencing January 1, 2022, the operator shall reduce the annual volume of vented and flared natural gas on a statewide basis in order to capture ninety-eight percent of the natural gas produced from its wells no later December 31, 2026. The division shall calculate and publish each operator's baseline natural gas capture rate based on the operator's 2021 monthly data reported on form C-115B. In each calendar year between January 1, 2022 and December 31, 2026, the operator shall increase the percentage of natural gas captured based on the following formula: (2021 baseline loss rate) divided by five.

(1) The following table provides examples of the formula based on a range of baseline natural gas capture rates.

Baseline Natural Gas Capture Rate	Minimum Required Annual Natural Gas Capture Percentage Increase
90-98%	0-1.6%
80-89%	>1.6-3.6%
70-79%	>3.6-5.6%
0-69%	>5.6-20%

(2) If the operator's baseline capture rate is less than sixty percent, the operator shall develop and submit to the division for approval a plan to meet the minimum required annual capture percentage increase.

(3) An operator that acquires one or more wells from another operator shall include the acquired wells within its ~~comply with its~~ statewide natural gas capture requirements no later than December 1, 2026 unless the division approves a later date.

B. Accounting. No later than 45 days after January 1, 2022 and each year thereafter, the operator shall submit a report certifying compliance with the statewide gas capture requirements. The operator's volume of vented and flared natural gas shall be counted as produced natural gas and excluded from the volume of natural gas sold or used for beneficial use in the calculation of its statewide natural gas capture requirements, except for the following.

Commented [SR15]: If a malfunction by a third party, operator cannot take steps to limit the flaring.

Commented [SR16]: Appendix XXA proposes which categories will be included in the numerator and denominator.

~~**(1)** The operator may exclude from the volume of produced natural gas the volume of vented and flared natural gas pursuant to Subparagraph (a) of Paragraph (3) of Subsection E of 19.15.27.8 NMAC for which the operator timely filed, and the division approved, a form C-129.~~

(1) Subject to the division's approval, the operator may exclude natural gas from the volume of produced natural gas, specifically Subparagraph (p) of Paragraph (3) of Subsection E of 19.15.27.8 NMAC, provided that the operator identified the volume of natural gas, the reasons that the operator vented or flared the natural gas rather than capturing it and any other relevant information requested by the division.

~~**(3)** Subject to the division's approval, the operator may exclude natural gas that is beneficially used from the volume of produced natural gas, specifically Subparagraph (r) of Paragraph (3) of Subsection E of 19.15.27.8 NMAC, provided that the operator identified the volume of vented natural gas, the reasons that the operator vented the natural gas rather than capturing it and any other relevant information requested by the division.~~

(2) The operator may obtain a credit against its reported volume of lost natural gas by using a division-approved ALARM technology to monitor, discover, report, identify ~~isolate~~ or ~~and~~ make repairs to prevent leaks of natural gas. To obtain a credit, the operator shall

(a) use ALARM technology at least two times per calendar year;

(b) make the initial discovery using the ALARM technology; and

(c) identify ~~isolate~~ the leak of natural gas from its source ~~own well~~ within 48 hours of field verification ~~of discovery~~ and make the repair as necessary or mitigate within 30~~15~~ days of discovery.

(3) The operator may use a credit against its reported volume of lost natural gas reported on its C-115 ~~loss~~ no more than once in any 24~~13~~ month period following the division's approval of such credit.

(4) The credit shall be determined as follows:

(a) a credit of fifty ~~thirty~~ percent of the volume of lost natural gas discovered and managed in accordance with paragraph 3 above; and, ~~isolated within 48 hours of discovery and timely repaired if the leak occurs at the operator's well or production facilities;~~

(b) an additional credit of ten percent of the volume of lost natural gas if the operator uses ALARM technology no less than four times per year.

~~**(c)** an additional credit of ten percent if the operator uses ALARM technology and, as a result of such use, provides credible information to an unaffiliated operator and the division that the unaffiliated operator's well has a leak of natural gas within five business days of discovery.~~

(5) To obtain a credit, the operator shall submit an application to the division describing

(a) the ALARM technology used;

(b) the date of use of the ALARM technology, date of leak discovery, date of notification to the owner or operator, date of field verification, and date of isolation and/or repair;

(c) the estimated volume of the natural gas leak as reported by the ALARM technology and the annualized volume of the leak;

(d) a summary of the actions taken to isolate and/or repair the leak;

(e) a certification or other documentation that the owner or operator isolated and/or repaired the leak; and,

(f) a certification that the owner or operator did not know or have reason to know of the leak of natural gas before the discovery using ALARM technology.

~~**(a)** the ALARM technology;~~

~~**(b)** the date of monitoring, discovery, isolation and repair;~~

~~**(c)** the estimated volume of the natural gas lost and isolated after the date of discovery;~~

~~**(d)** a summary of the actions the operator took to isolate and repair the leak;~~

~~**(e)** visual documentation of the discovery and isolation;~~

~~**(f)** a certification that the operator did not know or have reason to know of the leak of natural gas before the discovery using ALARM technology;~~

~~**(g)** if applicable, the dates of each use of the ALARM technology; and~~

~~**(h)** if applicable, a copy of the information provided to the unaffiliated operator.~~

(8) Credits shall be used only if approved by the division, and only by the operator, and cannot be traded or used by another operator. The division shall approve the credits within 30 days of the operator submitting a complete application.

C. Violation of natural gas capture requirement. The division may pursue any action authorized by law against an operator that does not meet a statewide natural gas capture requirement, including to curtail a production allowance, withhold or deny a drilling permit, suspend or revoke an authorization to transport or assess a civil penalty.

D. Natural gas management plan.

(1) After May 31, 2021, the operator shall file a natural gas management plan with each APD. The operator may file a single natural gas management plan for multiple wells drilled from a single well pad or that will be connected to a central delivery point.

(2) The natural gas management plan shall describe the actions that the operator will take at each well to meet its statewide natural gas capture requirements, reduce waste, eliminate venting and flaring of natural gas to the greatest extent possible and maximize the efficient, safe and economic recovery of the state's oil and natural gas, and include the following information for each well:

(a) operator's name;

(b) name, API number, location and footage;

(c) drilling, completion and anticipated first production date;

(d) anticipated natural gas volume production in units of MCFD ~~annually for the first three years of production~~;

(e) existing natural gas gathering system contracted or anticipated to contract to gather the natural gas, including

(i) natural gas gatherer's name;

(ii) name and location of the natural gas gathering system;

(iii) distance in feet of pipeline required to connect to the natural gas gathering system; and,

(iv) name and location of the natural gas processing plant contracted or anticipated to contract to process the natural gas;

Commented [SR17]: This condition does not provide regulatory certainty. The gas capture requirements are complicated and engineering practices may not be able to reasonably foresee all future operating scenarios. We recommend this section be consistent with the enforcement condition in 19.15.28.23.C. "Violation of natural gas capture requirement. The division may pursue any action authorized by law against an operator that does not meet a statewide natural gas capture requirement."

Commented [SR18]: The current "Gas Capture Plan" form is sufficient since it is a snapshot in time at time of submittal. There are many added requirements that are considered Confidential Business Information (CBI) on both the operator and midstream side. Most of what is being asked to provide from the gas gatherer, the upstream operator, is not privy to the upstream operator or is unable to be obtained.

~~**(v)** maximum daily capacity of the natural gas pipeline and compressors;~~

~~**(vi)** current throughput of the natural gas pipeline and compressors;~~

~~**(vii)** anticipated daily capacity of the natural gas pipeline and compressors on the date of first sale;~~

~~**(viii)** anticipated throughput of natural gas pipeline and compressors on the date of first sale;~~

~~**(ix)** reliability of the natural gathering system, including the average annual system downtime; and~~

~~**(x)** other issues and expansion plans affecting the gathering of natural gas in the general area;~~

~~**(f)** detailed map depicting each existing, planned and anticipated natural gas gathering system in the general area, including~~

~~**(i)** natural gas gatherer's name;~~

~~**(ii)** gathering pipelines;~~

~~**(iii)** approximate route of gathering pipeline connecting the well to the natural gas gathering system;~~

~~**(iv)** reliability of the natural gas gathering system, including the average annual system downtime; and~~

~~**(v)** name and location of the natural gas processing plant receiving or anticipated to receive natural gas from the natural gas gathering system;~~

(f) detailed flowback strategy, including

(i) temporary equipment to be used during flowback to reduce the venting of natural gas, including sand traps and settling tanks; and

(ii) measures to be used to flare natural gas if such natural gas cannot be routed immediately and directly to a sales line;

(g) options for the beneficial use of natural gas that cannot be connected to a natural gas gathering system; and if the operator determines, based on the available information at the time of submittal, that a natural gas gathering system will not be available or will not have capacity on the date of first production from the well to transport one hundred percent of the anticipated volume of natural gas produced, the operator shall submit a venting and flaring plan, with the natural gas management plan, containing a detailed analysis of the potential alternative uses for the natural gas until a gathering system is available that describes how the operator will avoid venting and flaring natural gas from the well including

(i) power generation on lease;

(ii) power generation for grid;

(iii) compression on lease;

(iv) liquids removal on lease;

(v) reinjection for underground storage;

(vi) reinjection for temporary storage;

(vii) reinjection for enhanced oil recovery; ~~and~~

(viii) other alternative uses approved by the division; and,

(ix) beneficial use, as defined herein.

(3) After the operator submits the natural gas management plan, if the natural gas gathering system becomes unavailable or will not have capacity to transport one hundred percent of the production 30 days prior to spud of the well ~~from the well, no later than 30 days after becoming aware of such information~~, the operator shall submit for ~~the division's approval~~ a revised venting and flaring plan to the division containing the information specified above in Paragraph (2) of Subsection D of 19.15.27.9 NMAC.

(4) The operator shall certify that it has communicated with the dedicated gas gatherer the anticipated volumes and that the submitted Gas Management Plan is true and accurate to the best of their knowledge. ~~the following statements:~~

~~**(a)** the operator communicated with one or more operators of natural gas gathering systems in the general area about transporting natural gas from the well;~~

~~**(b)** the operator provided each operator of a natural gas gathering system in the general area with the location; dates of drilling, completion and anticipated first production; and anticipated volume of natural gas production in units of MCFD for the first three years of production of the well; and~~

~~**(c)** the operator determined that there is or will be~~

~~**(i)** a natural gas gathering system in the general area with sufficient capacity to transport natural gas on the date of anticipated first production of the well; or~~

~~**(ii)** a natural gas gathering system in the general area with sufficient capacity to transport natural gas during the anticipated productive life of the well.~~

~~**(5)** The operator shall include a certification from each operator of a natural gas gathering system in the general area stating that~~

~~**(i)** the operator complied with Subparagraphs (a) and (b) of Paragraph (4) of Subsection D of 19.15.27.9 NMAC; and~~

~~**(ii)** the operator of the natural gas gathering system concurs in the operator's determination in Items (i) or (ii) of Subparagraph (c) of Paragraph (4) of Subsection D of 19.15.27.9 NMAC.~~

(5) If the operator does not make the certifications or submit a complete venting and flaring plan the division may ~~an adequate venting and flaring plan, or if the division determines that the operator will not have adequate natural gas takeaway capacity at the time a well will be spud, the division may~~

(a) deny the APD; or

(b) conditionally approve the APD.

[19.15.27.9 NMAC – N, xx/xx/xx]

Commented [SR19]: Can OCD provide examples of the conditions that would be attached? How does OCD plan to track this in their system?

TITLE 19 NATURAL RESOURCES AND WILDLIFE
CHAPTER 15 OIL AND GAS
PART 28 NATURAL GAS GATHERING SYSTEMS

Commented [SR20]: While PBPA has concerns about the requirements under Part 28, our member's focus has been on the upstream impacts of this rule and we recommend the OCD consult with midstream operators and associations for concerns and recommended changes to Part 28.

19.15.28.1 ISSUING AGENCY: Oil Conservation Commission.
[19.15.28.1 NMAC – N, xx/xx/xx]

19.15.28.2 SCOPE: 19.15.28 NMAC applies to persons engaged in oil and gas gathering and processing within New Mexico.
[19.15.28.2 NMAC – N, xx/xx/xx]

19.15.28.3 STATUTORY AUTHORITY: 19.15.28 NMAC is adopted pursuant to the Oil and Gas Act, Section 70-2-6, Section 70-2-11 and Section 70-2-12 NMSA 1978.
[19.15.27.3 NMAC – N, xx/xx/xx]

19.15.28.4 DURATION: Permanent.
[19.15.27.4 NMAC – N, xx/xx/xx]

19.15.28.5 EFFECTIVE DATE: [DATE], unless a later date is cited at the end of a section.
[19.15.28.5 NMAC – N, xx/xx/xx]

19.15.28.6 OBJECTIVE: To regulate the natural gas gathering systems to prevent waste and protect correlative rights, public health and the environment.
[19.15.28.6 NMAC – N, xx/xx/xx]

19.15.28.7 DEFINITIONS: Definitions shall have the meaning specified in 19.15.2 NMAC except as specified below.

A. **"ALARM"** means advanced leak and repair monitoring.
B. **"AVO"** means audio, visual and olfactory.
C. **"CP"** means cathodic protection.
D. **'Emergency"** means a temporary, infrequent and unavoidable event in which the loss of gas is uncontrollable or necessary to avoid a risk of an immediate and substantial adverse impact on safety, public health or the environment, but does not include an event arising from or related to:

(1) the operator's failure to install appropriate equipment of sufficient capacity to accommodate the anticipated or actual rate and pressure of the natural gas gathering system;

(2) the operator's failure to limit gathering when the volume exceeds the capacity of the transmission or distribution system;

(3) scheduled maintenance;

(4) the operator's negligence, including a recurring equipment failure; or

(5) two or more emergencies experienced by the operator within the preceding 60 days, unless the division determines the operator could not have reasonably anticipated the current event and it was beyond the operator's control.

E. **"Flare" or "Flaring"** means the controlled combustion of natural gas in a device designed for that purpose.

F. **"Flare stack"** means an appropriately designed stack equipped with a burner used for the combustion and disposal of natural gas.

G. **"Gathering pipeline"** means a pipeline that gathers natural gas from the custody transfer point to the connection point with a natural gas processing plant or transmission or distribution system.

H. **"GIS"** means geographic information system.

I. **"GPS"** means global positioning system.

J. **"Malfunction"** means a sudden, unavoidable failure or breakdown of equipment beyond the reasonable control of the operator that substantially disrupts operations and requires correction, but does not include a failure or breakdown that is caused entirely or in part by poor maintenance, careless operation or other preventable equipment failure or breakdown.

K. **"MAOP"** means maximum allowable operating pressure.

L. **"Natural gas"** means a gaseous mixture of hydrocarbon compounds, primarily composed of methane, and includes both casinghead gas and gas as defined in 9.15.2.7 NMAC.

M. **"Natural gas gathering system"** means the gathering pipelines and associated facilities that compress, dehydrate or treat natural gas from the custody transfer point to the connection point with a natural gas processing plant or transmission or distribution system.

N. **"New gathering pipeline"** means a gathering pipeline installed after {effective date of rule}.

O. **"Vent" or "Venting"** means the release of uncombusted natural gas to the atmosphere.

[19.15.28.7 NMAC – N, xx/xx/xx]

19.15.28.8 **RECORDS:** For the life of a new gathering pipeline, the operator shall maintain a record of the route, materials, design criteria, technical standards, MAOP, installation, pressure and other integrity tests, documentation, inspections, maintenance, repairs, corrosion control and cover and marking; transfer the records to a subsequent operator; and make such records available for inspection by the division upon request.

[19.15.28.8 NMAC – N, xx/xx/xx]

19.15.28.9 **MATERIALS:** The operator shall use pipe materials and components for a new gathering pipeline that are

A. able to maintain structural integrity under the MAOP and other operating conditions, including temperature;

B. compatible with the natural gas to be transported; and

C. satisfy the current API standard.

[19.15.28.9 NMAC – N, xx/xx/xx]

19.15.28.10 DESIGN: The operator shall design each component of a new gathering pipeline to

A. prevent failure by minimizing internal and external corrosion and the effect of transported fluids;

B. withstand MAOP and other internal loadings without impairment;

C. withstand anticipated external pressures and loads that may be imposed after installation;

D. allow for maintenance, periodic cleaning, integrity testing and other technology-based inspection tools; and

E. have adequate controls and protective equipment to prevent operation above the MAOP.

[19.15.28.10 NMAC – N, xx/xx/xx]

19.15.28.11 CONSTRUCTION:

A. The operator shall construct a new gathering pipeline in accordance with recognized and generally accepted industry practices.

B. The operator shall not install a new gathering pipeline or other component unless it has been visually inspected at the site of installation to ensure that it is not damaged.

[19.15.28.11 NMAC – N, xx/xx/xx]

19.15.28.12 COVER:

A. The operator shall place at least 30" of cover in normal soil and 18" of cover in consolidated rock over a new gathering pipeline.

B. The operator shall provide additional appropriate cover and protective measures at rail, road and water crossings of a new gathering pipeline.

C. The operator may request a variance from a requirement of 19.15.28.12 NMAC. The variance request shall include:

(1) a statement explaining the need for a variance; and

(2) a written demonstration that the variance will provide equal or better protection of public health and the environment.

D. The division shall approve, approve with conditions, or deny the variance within 60 days of receipt. If the division denies the variance, it shall provide the operator with the reasons for denial. If 60 days have lapsed without a response from the division, then the variance is deemed denied.

[19.15.28.12 NMAC – N, xx/xx/xx]

19.15.28.13 LOCATION AND MARKING:

A. The operator shall file with the division a GIS digitally formatted as-built map

(1) for a new gathering pipeline, no later than 90 days after putting the gathering pipeline into service;

(2) for a natural gas gathering system, no later than May 31, 2020 or 90 days after putting the natural gas gathering system into service; or

(3) for an addition to an existing gathering pipeline or natural gas gathering system, no later than 90 days after putting the addition into service.

B. The operator shall file with the division an updated GIS digitally formatted as-built map of its gathering pipeline and natural gas gathering system not less than annually.

C. The operator shall install and maintain markers that identify the location of a new gathering pipeline when crossing a public right-of-way or utility easement, except that markers shall be placed in a manner to reduce the possibility of damage or interference with surface use if practicable and the surface owner grants permission.

D. For each new gathering pipeline that transports natural gas containing a hydrogen sulfide concentration equal to or greater than 100 ppm, the operator shall install and maintain markers that conform with the current ANSI standard Z535.1-2002 (Safety Color Code). The markers shall be readily readable and contain the words "poison gas" and other information sufficient to warn the public of the potential hazard. The operator shall prominently post the markers at locations, including entrance points and road crossings, sufficient to warn the public of the potential hazard.

[19.15.28.13 NMAC – N, xx/xx/xx]

19.15.28.14 INSPECTION:

A. The operator shall retain a certified third-party inspector who shall inspect a new gathering pipeline with an outside diameter of 8" or greater before placing the gathering pipeline into service.

B. The operator shall maintain a record of the inspection, including the certification of the inspector and the inspector's certification that the gathering pipeline was constructed as prescribed by the manufacturer's specifications and in accordance with 19.15.28 NMAC.

[19.15.28.14 NMAC – N, xx/xx/xx]

19.15.28.15 PRESSURE TESTS: Before the operator places into service a new gathering pipeline, the operator shall establish the MAOP, which shall not exceed eighty percent of the internal pressure rating for the gathering pipeline, using the current API recommended practice.

[19.15.28.15 NMAC – N, xx/xx/xx]

19.15.28.16 START-UP NOTIFICATION: After the operator inspects and pressure tests a new gathering pipeline, and no later than 30 days before the operator intends to place the gathering pipeline into service, the operator shall notify the division in writing.

[19.15.28.16 NMAC – N, xx/xx/xx]

19.15.28.17 CORROSION CONTROL:

A. The operator shall electronically inspect the coating of a new gathering pipeline to be used in underground service prior to construction using a coating deficiency detector, such as scratch, bubble or "holiday", to check for faults not observable by visual examination. The

operator shall operate the detector in accordance with the manufacturer's specifications and at a voltage level appropriate for the electrical characteristics of the gathering pipeline.

B. During construction, the operator shall coat all joints, fittings and tie-ins with materials compatible with the coating on the gathering pipeline, which shall

(1) be designed to mitigate corrosion;

(2) have sufficient adhesion to the metal surface to prevent under-film migration of moisture;

(3) be sufficiently ductile to resist cracking;

(4) have enough strength to resist damage due to handling and soil stress;

(5) support any supplemental CP system; and

(6) if the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

C. The operator shall install a CP system on a new gathering pipeline that meets or exceeds the minimum criteria set forth in the National Association of Corrosion Engineers SP0169-2013, Control of External Corrosion on Underground or Submerged Metallic Piping Systems, 2013 Edition, including

(1) sufficient current to protect the gathering pipeline and distribute the current to achieve the selected CP criteria;

(2) minimization of stray current on neighboring underground structures;

(3) a design life commensurate with the required life of the gathering pipeline;

(4) adequate allowance for anticipated changes to current requirements over the design life of the CP system;

(5) location of anodes, cable, test station and other equipment to minimize the possibility of disturbance or damage; and

(6) sufficient monitoring to test and evaluate the effectiveness of the CP system.

[19.15.28.17 NMAC – N, xx/xx/xx]

19.15.28.18 CP MONITORING AND INTEGRITY MANAGEMENT FOR NEW AND EXISTING GATHERING PIPELINES:

A. The operator shall test a new or existing gathering pipeline for adequate CP every two years.

B. The operator shall inspect the rectifier or other impressed current power source for proper operation each calendar quarter with at least 60 days between inspections.

C. The operator shall electrically check additional components for proper performance each calendar quarter with at least 60 days between inspections.

D. The operator shall promptly correct abnormal internal corrosion, including increasing pigging, using corrosion inhibitors, coating the gathering pipeline with an appropriate material such as epoxy paint or other plastic liner or implementing a combination of these actions.

[19.15.28.18 NMAC – N, xx/xx/xx]

19.15.28.19 MAINTENANCE, REPLACEMENT AND REPAIR FOR NEW AND EXISTING NATURAL GAS GATHERING SYSTEMS:

A. Maintenance.

(1) The operator shall take reasonable actions to prevent the failure and leakage and minimize corrosion of a new or existing natural gas gathering system.

(2) If the operator discovers a condition that could adversely affect the safe and proper operation of a natural gas gathering system, the operator shall correct the condition as soon as possible, provided however that the operator shall cease the operation of the natural gas gathering system or segment of gathering pipeline if the condition presents an immediate hazard to persons or property until the condition is corrected.

(3) When the operator discovers a condition that affects the integrity of a natural gas gathering system, it shall immediately investigate, report and correct the condition and report and remediate any releases in accordance with Subsection C of 19.15.28.22 NMAC.

(4) The operator shall take reasonable precautions to prevent the unintentional release of natural gas during maintenance of a natural gas gathering system.

(5) During scheduled maintenance of a natural gas gathering system, the operator shall flare the natural gas during blowdown using a portable flare stack which complies with the flare stack standards in Paragraph (5) of Subsection D of 19.15.27.8 NMAC.

(6) During unscheduled maintenance of a natural gas gathering system, the operator shall make every attempt possible to flare the natural gas during blowdown of a gathering pipeline using a portable flare stack that complies with the flare stack standards in Paragraph (5) of Subsection D of 19.15.27.8 NMAC.

B. Replacement or repair.

(1) The operator shall replace or repair a component in a new or existing natural gas gathering system in a safe manner that prevents injury to persons or damage to equipment or property.

(2) The operator shall not use any pipe, valve or fitting to replace or repair a new or existing gathering pipeline unless the component meets the construction requirements of 19.15.28.11 NMAC.

(3) The operator shall not replace or repair any pipe, valve or fitting on a new or existing gathering pipeline unless the replacement or repair is designed to the MAOP.

(4) The operator shall verify the integrity of any replaced or repaired segment of a new or existing gathering pipeline by using a smart pig or other division-approved method before returning the gathering pipeline to service.

(5) The operator shall conduct a replacement or repair in accordance with the manufacturer's specifications or an applicable technical standard.

(6) The operator shall replace or repair each segment of pipe, valve or fitting that leaks or is unsafe before returning a gathering pipeline to service.

(7) While conducting a repair, the operator shall take reasonable precautions to prevent the unintentional release of natural gas during replacement and repair of a new or existing natural gas gathering system.

(8) During scheduled replacement or repair of a new or existing natural gas gathering system, the operator shall flare the natural gas during blowdown using a portable flare stack which complies with the flare stack standards in Paragraph (5) of Subsection D of 19.15.27.8 NMAC.

(9) During unscheduled replacement or repair of a new or existing natural gas gathering system, the operator shall make every attempt possible to flare the natural gas during

blowdown using a portable flare stack which complies with the flare stack standards in Paragraph (5) of Subsection D of 19.15.27.8 NMAC.

C. Reporting to affected upstream operators.

(1) No less than seven days prior to the date of scheduled maintenance, replacement or repair of a natural gas gathering system, the operator shall provide written notification to upstream operators whose natural gas is gathered by the system of the date and expected duration that the system will not gather natural gas.

(2) As soon as possible but no more than 24 hours after discovery of the need for unscheduled maintenance, replacement or repair, the operator shall provide written notification to upstream operators whose natural gas is gathered by the system of the date and expected duration that the system will not gather natural gas.

(3) The operator shall make and keep a record of each notification for not less than five years and make such records available for inspection by the division upon request.

[19.15.28.19 NMAC – N, xx/xx/xx]

19.15.28.20 INTEGRITY MANAGEMENT PROGRAM FOR NEW AND EXISTING GATHERING PIPELINES: The operator shall implement one of the following integrity management programs for new and existing gathering pipelines.

A. An annual pressure test. When performing the annual pressure test the operator shall ensure

(1) the MAOP is maintained for a minimum of 30 minutes after reaching MAOP;

(2) the gathering pipeline does not leak;

(3) the pressure loss does not exceed ten percent; and

(4) the pressure is stable for the last five minutes of the pressure test.

B. Continuous pressure monitoring. If using continuous pressure monitoring the operator shall ensure

(1) pressure data is monitored continuously, i.e., 24 hours per day and seven days a week, and the monitoring can detect a suspected or actual failure of integrity or pressure anomaly;

(2) the gathering pipeline can be shut-in for repairs immediately upon the detection of a suspected or actual failure of integrity or pressure anomaly either through automation or a documented, manual process; and

(3) the continuous monitoring program is documented annually, including a suspected or actual integrity failure or pressure anomaly, and a detailed description of the operator's actions to correct such failure or anomaly.

C. Smart pigging conducted every three years. If using smart pigging, the operator shall

(1) use a smart pig that is capable of measuring flowline wall thickness and flowline defects that could affect integrity, including the measurement of metal loss; and

(2) if the operator does not have a geodatabase file of the flowline, use a smart pig that has GPS capabilities to the extent such capabilities do not materially compromise the ability of the smart pig to conduct the integrity test.

[19.15.28.20 NMAC – N, xx/xx/xx]

19.15.28.21 INSPECTION STANDARDS FOR NEW AND EXISTING GATHERING PIPELINES: The operator shall perform an annual instrument monitoring of the entire length of a new and existing gathering pipeline using an AVO technique, ALARM technology or other valid method to detect a failure of integrity, leak or release, such as stress vegetation or soil discoloration. The operator shall record and report to the division the date and time of the monitoring, the method and technology used and the name of the employee(s) who conducted the monitoring. If the operator uses ALARM technology to detect and isolate a leak within 48 hours and repair within 15 days of discovery, the operator may obtain a credit against its reported volume of lost natural gas pursuant to Paragraph (3) of Subsection B of 19.15.28.23 NMAC.
[19.15.28.21 NMAC – N, xx/xx/xx]

19.15.28.22 VENTING AND FLARING OF NATURAL GAS FROM NATURAL GAS GATHERING SYSTEMS:

A. Venting and flaring of natural gas from a natural gas gathering system constitutes waste and is prohibited except as authorized below in Subsection B of 19.15.28.22 NMAC. An operator has a general duty to maximize the gathering of natural gas and to minimize the release of natural gas to the atmosphere.

B. An operator shall not vent or flare natural gas, except

(1) to the extent authorized by a valid federally enforceable air quality permit issued by the environment department;

(2) during an emergency or malfunction, but only to avoid a risk of an immediate and substantial adverse impact on safety, public health or the environment;

(3) during the following activities to the extent authorized by applicable state and federal law regulating the emission of hydrocarbons and volatile organic compounds:

(a) scheduled repair and maintenance, including blowing down and depressurizing equipment to perform repair and maintenances;

(b) normal operation of a gas-activated pneumatic controller or pump;

(c) normal operation of a dehydration unit;

(d) normal operation of a compressor or compressor engine;

(e) normal operation of a storage tank or other low-pressure production vessel, but not including venting from a thief hatch that has not been fully and timely closed or from a seal that has not been maintained on an established schedule;

(f) gauging or sampling of storage tanks or other low-pressure vessels;

(g) loading out liquids from a storage tank or other low-pressure vessels to transport vehicles;

(h) a blowdown to repair a gathering pipeline;

(i) pigging a gathering pipeline; and

(j) purging a gathering pipeline.

(4) The operator shall conduct a weekly AVO inspection to confirm that all equipment is operating properly and there is no venting except as allowed in Subsection B of 19.15.28.22 NMAC.

C. Measurement and reporting of vented and flared natural gas.

(1) The operator shall measure the volume of natural gas that is vented, flared or beneficially used by the natural gas gathering system regardless of the reason or authorization for such venting and flaring.

(2) The operator shall install equipment to measure the volume of vented and flared natural gas from a natural gas gathering system.

(3) Measuring equipment shall be designed in accordance with the accuracy ratings and design standards in 43 C.F.R. § 3175.29.

(4) Measuring equipment shall not be designed or equipped with a manifold that allows the diversion of natural gas around the metering element except for the sole purpose of inspecting and servicing the measuring equipment.

(5) For an event for which metering is not practicable the operator may estimate the volume of vented and flared natural gas.

(6) The operator shall report the lost natural gas for each month on a volumetric and percentage basis on form C-115B.

(a) To calculate the lost natural gas on a volumetric basis, the operator shall deduct the volume of natural gas delivered, used for beneficial use and vented or flared during an emergency, from the volume of natural gas gathered.

(b) To calculate the lost natural gas on a percentage basis, the operator shall add the volume of natural gas sold, used for beneficial use and vented or flared during an emergency, and divide by the total volume of natural gas gathered.

(7) The operator shall report the volume of vented and flared natural gas for each month in each category in Paragraph (7) of Subsection C of 19.15.28.22 NMAC on form C-115B. The operator shall make and keep records of the measurements and estimates, including how the estimated volumes were calculated, for not less than five years and make such records available for inspection by the division upon request. The categories are

(a) emergency;

(b) non-scheduled maintenance;

(c) equipment malfunction by operator;

(d) equipment malfunction by third party;

(e) routine equipment repair and maintenance, including blowdown;

(f) pilot gas for combustion devices;

(g) purge gas to test or fuel combustion devices;

(h) gathering pipeline blowdown;

(i) gathering pipeline purging;

(j) gathering pipeline pigging;

(k) uncontrolled storage tanks;

(l) venting in excess of the design specifications of pneumatic controllers and pumps as a result of malfunction or improper or infrequent maintenance;

(m) commencing on January 1, 2022, venting as a result of normal operation of pneumatic controllers and pumps, except that in November 2021, the operator shall report the volume of vented natural gas that it reported to a state or federal agency, as revised to include data from pneumatic controllers and pumps in use during 2021 that were not included in the 2020 report;

(n) thief hatches that are not properly closed or maintained; and

(o) other not described above.

(8) The operator shall notify the division for any period of venting or flaring that exceeds eight hours and of all venting and flaring attributed to emergency or malfunction of any duration by submitting a form C-129 no later than 24 hours after the commencement of venting and flaring.

(a) The operator's form C-129 shall provide and certify the accuracy of the following information:

(i) operator's name;
(ii) name and type of facility;
(iii) equipment involved;
(iv) analysis of vented and flared natural gas;
(v) date and time that venting or flaring occurred;
(vi) the measured or estimated volume of vented or flared natural gas;
(vii) cause and nature of venting or flaring;
(viii) steps taken to limit the duration and magnitude of venting or flaring; and
(ix) corrective actions taken to eliminate the cause and recurrence of venting or flaring.

(b) At the division's request, the operator shall provide additional information by the specified date and a certification of the accuracy of the additional information.

(8) Upon the environment department's request, the operator shall promptly provide a copy of any form filed pursuant to 20.2.28 NMAC.
[19.15.28.22 NMAC – N, xx/xx/xx]

19.15.28.23 STATEWIDE NATURAL GAS CAPTURE REQUIREMENTS:

A. Statewide natural gas capture requirements. Commencing January 1, 2022, the operator shall reduce the annual volume of vented and flared natural gas on a statewide basis in order to capture ninety-eight percent of the natural gas gathered by December 31, 2026. The division shall calculate and publish each operator's baseline gas capture rate based on the operator's 2021 monthly data reported on form C-115B. In each calendar year between January 1, 2022 and December 31, 2026, the operator shall increase the percentage of natural gas captured based on the following formula: (2021 baseline loss rate) divided by five.

(1) The following table provides examples of the formula based on a range of baseline natural gas loss capture rates.

Baseline Natural Gas Capture Rate	Minimum Required Annual Natural Gas Capture Percentage Increase
90-98%	0-1.6%
80-89%	>1.6-3.6%
70-79%	>3.6-5.6%
0-69%	>5.6-20%

(2) If the operator's baseline capture rate is less than sixty percent, the operator shall develop and submit to the division for approval a plan to meet the minimum required annual capture percentage increase.

(3) An operator that acquires a natural gas gathering system from another operator shall comply with its statewide natural gas capture requirements no later than December 1, 2026, unless the division approves a later date.

B. Accounting. The operator's volume of vented and flared natural gas shall be counted as gathered natural gas and excluded from the volume of natural gas delivered or used for beneficial use in the calculation of its statewide natural gas capture requirements, except for the following

(1) No later than 45 days after January 1, 2022 and each year thereafter, the operator shall submit a report certifying compliance with the statewide gas capture requirements. The operator may exclude from the volume of produced natural gas the volume of vented and flared natural gas pursuant to Subparagraph (a) of Paragraph (7) of Subsection C of 19.15.28.22 NMAC for which the operator timely filed, and the division approved, a form C-129.

(2) Subject to the division's approval, the operator may exclude natural gas that is beneficially used from the volume of produced natural gas, specifically Subparagraph (m) of Paragraph (7) of Subsection C of 19.15.28.22 NMAC, provided that the operator identified the volume of vented natural gas, the reasons that the operator vented the natural gas rather than capturing it and any other relevant information requested by the division.

(3) The operator may obtain a credit against its reported volume of lost natural gas by using a division-approved ALARM technology to monitor, discover, report, isolate and make repairs to prevent leaks of natural gas. To obtain a credit, the operator shall

(a) use ALARM technology at least two times per calendar year;

(b) make the initial discovery using the ALARM technology; and

(c) isolate the leak of natural gas from its own natural gas gathering system within 48 hours of discovery and make the repair within 15 days of discovery.

(4) The operator may use a credit against its reported volume of lost natural gas no more than once in any 13-month period following the division's approval of such credit.

(5) The credits shall be determined as follows:

(a) a credit of thirty percent of the volume of natural gas discovered and isolated within 48 hours of discovery and timely repaired if the leak occurs at the operator's natural gas gathering system;

(b) an additional credit of ten percent if the operator uses ALARM technology no less than four times per year;

(c) an additional credit of ten percent credit if the operator uses ALARM technology, and as a result of such use, provides credible information to an unaffiliated operator and the division that the unaffiliated operator's natural gas gathering system has a leak of natural gas within five business days of discovery.

(6) To obtain a credit, the operator shall submit an application to the division describing

(a) the ALARM technology;

(b) the date of monitoring, discovery, isolation and repair;

(c) the estimated volume of the natural gas lost and isolated after the date of discovery;

(d) a summary of the actions the operator took to isolate and repair the leak;

(e) visual documentation of the discovery and isolation;

(f) a certification that the operator did not know or have reason to know of the leak of natural gas before the discovery using ALARM technology;

(g) if applicable, the dates of each use of the ALARM technology; and

(h) if applicable, a copy of the information provided to the unaffiliated operator.

(7) A credit shall be used only if approved by the division, and only by the operator, and cannot be traded or used by another operator.

C. Violation of natural gas capture requirement. The division may pursue any action authorized by law against an operator that does not meet a statewide natural gas capture requirement.

D. Natural gas management plan.

(1) For a natural gas gathering system placed into service after {effective date of rule}, the operator shall file a natural gas management plan no later than 90 days prior to the date that the natural gas gathering system is placed into service. For a natural gas gathering system placed into service before {effective date of rule}, the operator shall file a natural gas management plan no later than May 31, 2020. The operator shall update the natural gas management plan to reflect any changes in the natural gas gathering system on the annual anniversary date of its first filing of the natural gas management plan.

(2) The natural gas management plan shall describe the actions that the operator will take for each natural gas gathering system to meet its statewide natural gas capture requirements, reduce waste, eliminate venting and flaring of natural gas to the greatest extent possible and maximize the efficient, safe and economic recovery of the state's oil and natural gas, and include the following information for each natural gas gathering system

(a) operator's name;

(b) name and list of facilities located within the natural gas gathering system, length of gathering pipelines and a GIS digitally formatted as-built map of the gathering pipeline and associated components of the natural gas gathering system;

(c) current and anticipated volume of natural gas gathered at each custody transfer in units of MCFD within the natural gas gathering system for the next three years; and

(d) description of the transmission or distribution system to which the natural gas gathering system is connected.

[19.15.28.23 NMAC – N, xx/xx/xx]

19.15.27.8.E.(3) C-115~~B~~ Consolidated Categories & Gas Capture Calculation

PBPA Proposed Categories	Rule 27 OCD Categories (Upstream)	Include in GC Numerator	Include in GC Denominator	Measured, Calculated, or Either[1]	Example Tank Battery with 5000 BOPD Production Rate GOR=3000
Sales Gas	Sales Gas	Yes	Yes	Measured	15 MMscfd
Beneficial Use C-115 Non-Transported Disposition Code U	(i) pilot gas for combustion devices;	Yes	Yes	Either	up to 0.10 MMscfd
	(j) purge gas to test or fuel combustion devices;				
	(t) other not described above. Other benefical uses for normal operations (e.g. burners, engines) as approved by OCD				
Necessary High Pressure (HP) Flare & Vent C-115 Non-Transported Disposition Code V or F	(a) emergency;	Yes	Yes	Either	0 - 15 MMscfd
	(b) non-scheduled maintenance; less than 72 hours				
	(c) equipment malfunction by operator; less than 72 hours				
	(d) equipment malfunction by third party; less than 72 hours				
	(g) routine equipment repair and maintenance, including blowdown and depressurization; less than 72 hours				
	(p) natural gas quality that is not suitable for transportation and processing because of a high percentage of N2, O2, CO2, H2S, or other impurities;				
	New - Commissioning of new pipelines, equipment, and facilities				
	New - Flaring after processing through remote capture equipment				
	(t) other not described above. Other HP Flare & Vent as approved by OCD				
Unnecessary HP Flare & Vent (Lost Gas) C-115 Non-Transported Disposition Code V or F	(b) non-scheduled maintenance; greater than 72 hours	No	Yes	Either	0 - 15 MMscfd
	(c) equipment malfunction by operator; greater than 72 hours				
	subset of (c) Malfunction due to poor maintenance, careless operation, or other preventable equipment failure				
	(d) equipment malfunction by third party; greater than 72 hours				
	(g) routine equipment repair and maintenance, including blowdown and depressurization; greater than 72 hours				
	(o) insufficient pipeline availability or capacity;				
	(t) other not described above. Other HP Flare & Vent as approved by OCD				
Infeasable to measure or calculate with reasonable accuracy for the purposes of accounting for production or for compliance with statewide gas capture requirements In the case of "uncontrolled storage tanks", these volumes are normal operating losses regulated by NMED Not reported on C-115	(e) drilling operations;	No	No	N/A	up to 0.20 MMscfd
	(f) completion operations;			N/A	
	(h) routine downhole maintenance, including operation of workover rigs, swabbing rigs, coiled tubing units and similar specialty equipment;			N/A	
	(k) manual liquid unloading;			N/A	
	(l) bradenhead tests;			N/A	
	(m) packer leakage tests;			N/A	
	(n) uncontrolled storage tanks;			N/A	
	(q) venting in excess of the design specifications of pneumatic controllers and pumps as a result of malfunction or improper or infrequent maintenance;			N/A	
	(r) commencing on January 1, 2022, venting as a result of normal operation of pneumatic controllers and pumps, except that			N/A	
	(i) in November 2021, the operator shall report the volume of vented natural gas that it reported to a state or federal agency, as revised to include data from pneumatic controllers and pumps in use during 2021 that were not included in the 2020 report; and			N/A	
	(ii) an operator who vents or flares less than 500,000 cubic feet per year of natural gas is exempted from this subparagraph;			N/A	
	(s) thief hatches that are not properly closed or maintained; and			N/A	
	(t) other not described above. Other LP Flare & Vent as approved by the OCD			N/A	

[1]Either: while it may not be feasible or possible to measure today, future technology may make it possible

Defintitions

Beneficial Use - gas produced from leases that is used for operations and production purposes.
High Pressure (HP) Gas - for the purposes of this rule will be defined as any gas at 15 PSIG or greater.
Low Pressure (LP) Gas - for the purposes of this rule will be defined as any gas lower than 15 PSIG.
Unsuitable Gas - gas that is unable to be sold due to quality.

Gas Capture Equation: Gas Capture % Proposal = $\frac{(Sales + Beneficial\ Use + Necessary\ HP\ Flare\ \&\ Vent)}{(Sales + Beneficial\ Use + Necessary\ HP\ Flare\ \&\ Vent + Unnecessary\ HP\ Flare\ \&\ Vent)}$