Comment on 20.2.50.115(E)(1)(b): Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

Comment on 20.2.50.115(E)(3): Redline required as record keeping is addressed under LDAR section. Redline required as an operator should have the option of not operating a unit (e.g. Tank) with a VRCU rather than having redundant control or backup control. For example, an operator could shut-in a well(s) to service a VRCU on the tanks receiving hydrocarbon fluid from that well (s) rather than have redundant control systems.

F. Recordkeeping requirements: The owner or operator of a control device or closed vent system shall maintain a record of the following:

(1) the certification of the closed vent system where applicable and ~~as~~ required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: ~~Wellhead sites~~Well production facilities, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Equipment leak and fugitive emissions -monitoring required by New Source Performance Standards, including but not limited to Subpart OOOO and Subpart OOOOa, 40 C.F.R. Part 60, as may be revised, may be used to satisfy the requirements of this 20.2.50.116 NMAC. A component is subject to the requirements if it is a gas vapor or light liquid component that contacts process fluid that is at least 10% VOC by weight. Components in water and/or air service are exempt from the requirements of 20.2.50.116 NMAC. Well production facilities and gathering and boosting sites producing or handling exclusively coal bed methane are not subject to the requirements of 20.2.50.116

Comment on 20.2.50.116.A. Redlined required to exempt facilities already performing robust equipment leak monitoring under New Source Performance Standards. The ten-percent VOC threshold is added to exempt from the rule components that do not contain liquids capable of emitting meaningful amounts of VOC. Similarly, NMOGA has added the exemption for water and/or air service components because these do not leak VOCs. Coal bed methane wells or gathering and boosting sites handling coal bed methane should also be excluded because they do not have the potential to emit VOC's due to equipment leaks since the gas they produce or handle has no VOC to emit and there are no hydrocarbon liquids produced or handled

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. ~~Default~~ Monitoring, inspection or testing requirements: Owners and operators shall comply with the following monitoring requirements: ~~and the monitoring requirements in 20.2.50.112 NMAC:~~

(1) The owner or operator of a ~~wellhead site~~well production facility or tank battery ~~facility~~ with an annual ~~average daily production of greater than 10 barrels of oil per day or an~~ average daily production or average daily throughput of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects which may include~~:~~ 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 or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be ~~be considered a leak; and~~

~~**(e)** a leak discovered by an AVO inspection shall be tagged with a visible tag~~ repaired in accordance with Subsection E if not repaired at the time of discovery. ~~and reported to management or their designee within three calendar days.~~

(2) The owner or operator of a ~~wellhead site~~well production facility or tank battery ~~facility~~ with an annual ~~average daily production of equal to or less than 10 barrels of oil per day or an~~ average daily production or average daily throughput of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S.EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for ~~wellhead sites~~well production facilities or tank battery facilities:

(i) annually at facilities with a PTE less than 10~~two~~ tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than ~~two~~ 10 tpy and less than ~~five~~ 25 tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than ~~five~~ 25 tpy

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations

(i) ~~quarterly~~ semi-annually at facilities with a PTE less than 25 tpy VOC; and

(ii) ~~monthly~~ quarterly at facilities with a PTE equal to or greater than 25 tpy VOC

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21 and by the instrument manufacturer;

~~(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 near, but nor more than, 10,000 ppm methane or n-hexane; and~~

(~~c~~b) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Leaks discovered pursuant to the leak detection methods of Paragraphs (3), (4) and (5) of Subsection C of 20.2.50.116 NMAC are not subject to enforcement by the department unless the owner or operator fails to perform the required repairs in accordance with Subsection E of 20.2.50.116 NMAC or keep required records in accordance with Subsection F of 20.2.50.116 NMAC.

(~~6~~7) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface. ~~or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;~~

(b) 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; and

(c) 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.

Comment on 20.2.50.116(C): Redline required as the "and" here creates significant confusion where 112 is a default monthly inspection. It also conflicts with 112's statement that default is monthly unless otherwise stated in the specific rule section. Ultimately, the reference is unnecessary when this leak program is a monitoring program.

Comment on 20.2.50.116(C)(1). (2): Redline required to align with OCD Waste Rule. As that rule and this one are focused on gas waste and gas related emissions, respectively, it is appropriate to apply flexibilities like this one based upon gas rate through the site.

Comment on 20.2.50.116(C)(1)(a): Redline required to limit to external AVO, and not requiring equipment to be opened up for internal inspection. AVO inspections can provide opportunities for operators to identify components at a facility that are not operating properly. The proposed language may be interpreted to require operators to open seals and gaskets to visually inspect for damage. This is not a common practice during an AVO inspection and may lead to unnecessary waste not typically associated with an AVO inspection. Incorporating this practice into an AVO inspection would also pose a safety issue when opening up the equipment to visually inspect for damage. Operators have specific practices, procedures, and guidelines for *how and when to open equipment such as seals and gaskets to check for damage.*

Comment on 20.2.50.116(C)(3)(a). The thresholds and inspection frequencies set in 20.2.50.116 C(3)(a) for requiring equipment leak surveys are unnecessarily stringent, result in less reductions than estimated, and impose unreasonable costs.

1. ***The ERG evaluation is flawed.*** The evaluation of VOC control quantities and costs, performed for NMED by ERG and presented in the ERG excel workbook titled "LDAR-Reductions-and-Costs-VOC-5-27-2021_erg-06-08-2021.xlsx" overstates the reductions that would be achieved by the rule and understates the costs of such reductions.
    a. ***Types of Survey Instrument and Reduction Percentages***. ERG assumes that companies would use an equal blend of Optical Gas Imaging (OGI) and Method 21 (handheld analyzer) instruments (500 ppm detection threshold) when doing surveys and averaged the reduction percentages for these two methods.
        i. Based on 2019 GHGRP reported survey types this is an incorrect assumption. Of 2,022 reported surveys, 1,714 (85%) were reported as using an OGI imaging instrument.
        ii. For this reason, NMOGA did not include Method 21 methodologies in any of their analyses.
    b. ***Model Plants – Well Production Facilities.*** The ERG analysis relied on a "model plant" that is not representative of New Mexico and does not represent the best data available.
        i. The ERG evaluation uses reductions and costs from the US EPA's: Control Techniques Guidelines for the Oil and Natural Gas Industry. EPA-453/B-16-001. October 2016 [hereafter, "2016 CTG"]; U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Sector Policies and Programs Division Research Triangle Park, North Carolina Table 9-11 of the 2016 CTG. Specifically, ERG used reductions and costs from tables 9-11, 9-12, and 9-13 from the 2016 CTG's to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at well production facilities (well sites)
        ii. These tables are based on "Model Plants" that EPA used to estimate potential emissions and reductions in the 2016 CTG's
        iii. The "Model Plants" in the 2016 CTG's were established by EPA for Natural Gas Well sites, Oil Well Sites with a GOR <300 scf/bbl, and Oil Well Sites with a GOR >= 300 scf/bbl. The counts of major equipment and components (valves, connectors, etc) for these model plants were based on information from an EPA/GRI study from 1996 (gas well sites) and 40 CFR Part 98, subpart W, Tables W-1B and W-1C (component counts for oil well sites). These EPA "Model Plants" represent a generic representation of well sites and are not specific to well sites in the San Juan and Permian Basins.
        iv. Based on equipment counts reported into the US EPA's Greenhouse Gas Reporting Program (40 CFR Part 98, subpart W) well production facilities in the San Juan and Permian Basins have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plants. The GHGRP based well site Model Plants are reflective of San Juan and Permian Basin sites and should be used preferentially to the generic CTG models.
    c. ***Inaccurate Reductions – Well Production Facilities.*** The failure to rely on the correct model led to unrepresentative conclusions.
        i. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the GHGRP based reduction estimates shows the effect of these differences.

Estimated Reductions Comparison - Tons Per Year VOC – OGI Surveys						
	ERG (CTG Basis)			NMOGA (GHGRP Basis)		
	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR
Annual	0.61	0.13	0.3	0.509	0.096	0.122
Semiannual	0.917	0.199	0.451	0.764	0.143	0.183
Quarterly	1.222	0.265	0.602	1.018	0.191	0.244

        ii. Coupling these lower reductions with the costs in ERG's analysis workbook yields the following comparison of costs per ton of VOC reduction at the different survey frequencies in the proposed rule.

Costs of VOC Reductions - $ per ton of VOC reduced – OGI Surveys						
	ERG (CTG Basis)			NMOGA (GHGRP Basis)		
	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR	Gas Well Site	Oil Well Site <300 GOR	Oil Well Site <300 GOR
Annual	$2,243	$10,343	$4,552	$2,686	$14,267	$11,226
Semiannual	$2,592	$11,954	$5,260	$3,124	$16,605	$12,975
Quarterly	$3,588	$16,553	$7,285	$4,299	$22,960	$17,973

iii. As this cost comparison table illustrates, by considering actual characteristics of well sites in the San Juan and Permian Basins rather than generic models based on old and non-specific data, the cost per ton of VOC reduction at well sites is meaningfully higher than projected by ERG.

d. ***Inaccurate Costs – Well production facilities.***

i. The costs used in the ERG analysis of 20.2.50.116 requirements for well sites are from the 2016 CTG's.

ii. In their December 2015 comments on the draft 2016 CTGs, the American Petroleum Institute (API) noted the estimated costs of leak surveys was significantly understated by EPA. The following excerpt from the API comments provide an overview of the costs underestimated by EPA.

EPA Did Not Consider Key Costs To Industry In Assessing The Cost Effectiveness Of Leak Detection Requirements Proposed.
In its cost analysis for the proposed control strategy for fugitives emissions, EPA did not adequately capture all of the costs associated with implementation of such a program. Specifically, in the cost-effectiveness evaluation, EPA underestimated the costs associated with:

- *Conducting leak surveys*
- *Completing repairs, and*
- *Maintaining the required recordkeeping, including the costs of developing and maintaining the corporate and site-specific monitoring plans.*

Further, EPA did not include several aspects beyond the cost of the actual survey work in its cost analysis, including:

- *Training of personnel*
- *Travel time and costs*
- *Equipment maintenance (e.g. monitoring device calibration)*

… Utilizing the more representative costs along with EPA's current estimates of emission reductions expected from the rule, the cost effectiveness of the proposed semi-annual OGI monitoring increases from EPA's estimate of $2,230 per well site to over $6,400 per site.

iii. Using the API cost of $6,400 per site with adjustment to a 2019 cost yields an estimated cost per ton of VOC reduction of $8,751 for the GHGRP based gas well site Model Plant and $7,253 for the 2016 CTG's gas well Model Plant.

iv. These additional costs support raising the monitoring thresholds to improve the feasibility of the rule.

2. Percent of components leaking, survey frequency and percent VOC reduction

a. In their December 17, 2018 comments to EPA regarding reconsideration of Subpart OOOOa (Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018)), the American Petroleum Institute (API) presented data from analysis of Subpart OOOOa leak surveys conducted by their member companies. API's analysis includes:

i. Two years of Subpart OOOOa Leak Survey Data for Sites Monitored at a Semi-Annual Frequency

ii. Over 6,000 total surveys across 3,482 sites

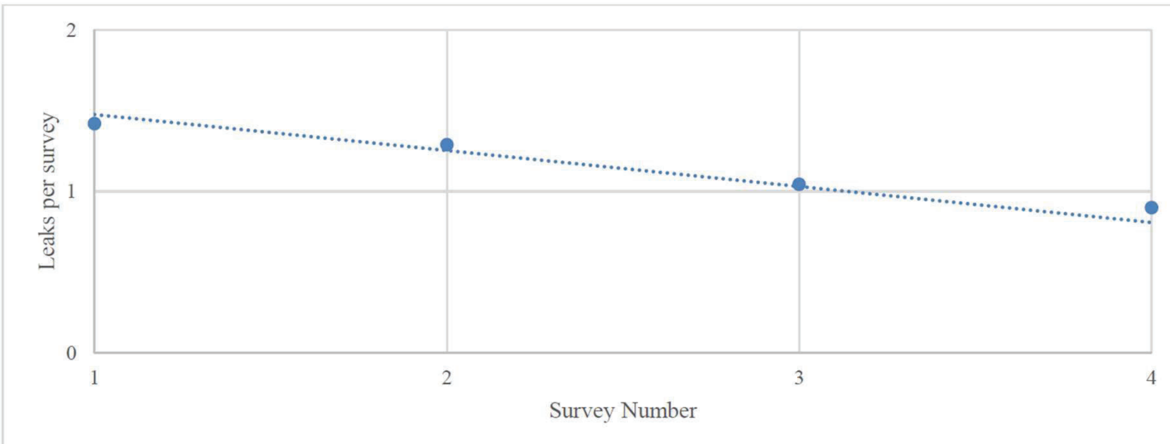
iii. Represents data from 13 different operators

b. API's analysis showed the following:

i. There are large number of sites that have no leaks (58% of initial well site surveys).

ii. The average number of leaking components per site is less than 2 components found leaking during the initial Subpart OOOOa survey and falls quickly to less than 1 leaking component found on average in subsequent surveys. These values are both below the 4 fugitive components that EPA assumed would require repair in each survey and even further below the number of leaks assumed in the EPA Leak Protocol Table 2-4 emission factors that were used to estimate emissions (See Figure 1 in Comment 1.1.3). In fact, nearly 92% of all surveys conducted across the 2-year period identified 4 or less leaking components per site.

Figure 1. Average Count of Leaks Found per Leak Survey Monitored per § 60.5397a



c. Additionally, a research study funded by the API and conducted by GHD found an overall component leak percentage of 0.42% at 67 varied upstream oil and gas sites. This peer reviewed paper "Equipment leak detection and quantification at 67 oil and gas sites in the Western United States" was published in 2019. (Pacsi, Adam & Ferrara, Tom & Schwan, Kailin & Tupper, Paul & Lev-On, Miriam & Smith, Reid & Ritter, Karin. (2019). Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth. 7. 29. 10.1525/elementa.368.)

d. This recent data further illustrates that the estimated VOC reductions in the 2016 CTG's used to evaluate 20.2.50.116 NMAC are overstated, the costs per ton of VOC reduction are higher, and the incremental reductions from increasing the frequency of leak surveys is lower than used in NMED's contractor's analysis.

e. This further supports NMOGA's recommendation that less frequent leak surveys at higher emissions threshold are appropriate for wells and tank batteries.

Comment on 20.2.50.116(C)(3)(b). The emissions thresholds and associated leak monitoring frequencies at 20.2.50.116(C)(3)(b) are overly stringent and not supported by NMED's analysis. These thresholds and frequencies should be adjusted as indicated above to better reflect the potential reductions and costs of leak monitoring.

1. Gathering and Boosting Sites.

a. For gathering and boosting sites, ERG used reductions and costs from table 9-14 from the 2016 CTG to estimate reductions and costs for annual, semi-annual, and quarterly inspection frequencies at gathering and boosting sites. For the monthly inspection frequency case, ERM used the Colorado cost per inspection for the annual cost. ERM then used the "CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases".

b. These tables are based on "Model Plants" that EPA used to estimate potential emissions and reductions in the 2016 CTG's

c. Similar to well production facilities, the "Model Plant" in the 2016 CTG, established by EPA for Gathering and Boosting sites major equipment and components (valves, connectors, etc), is based on old and limited information from an EPA/GRI study from 1996.

d. Based on a major recent study commissioned by the US Department of Energy and led by Colorado State University (Zimmerle, Daniel, Bennett, Kristine, Vaughn, Timothy, Luck, Ben, Lauderdale, Terri, Keen, Kindal, Harrison, Matthew, Marchese, Anthony, Williams, Laurie, & Allen, David. Characterization of Methane Emissions from Gathering Compressor Stations: Final Report. United States. https://doi.org/10.2172/1506681) gathering and boosting sites have, on average, less pieces of major equipment, less components, and less potential equipment leak emissions than the 2016 CTG Model Plant.

e. Less potential for equipment leaks translates to less reductions from a leak detection and repair program. Comparing the ERG CTG based reduction estimates and the CSU/DOE study-based reduction estimates shows the effect of these differences.

VOC Tons per Year Reduced per Gathering and Boosting Site			
OGI Inspection Frequency	**ERG Estimated**	**NMOGA Estimated**	
		San Juan	**Permian**
Annual	3.91	0.746	1.853
Semiannual	5.86	1.119	2.779
Quarterly	7.81	1.492	3.705
Monthly[a]	Not Shown	1.678	4.168
For the monthly OGI survey frequency, NMOGA used 90% reduction which is the Method 21 monthly reduction percentage stated by ERG minus the 2% differential for quarterly OGI surveys vs. quarterly Method 21 surveys.			

f. Using these more current and correct reduction estimates, NMOGA calculates the following costs per ton of VOC reductions for gathering and boosting sites in the San Juan basin and gathering and boosting sites in the Permian basin.

Cost per Ton of VOC Reduction - Gathering and Boosting Site		
OGI Inspection Frequency	**NMOGA Estimated**	
	San Juan	**Permian**
Annual	$10,837	$4,362
Semiannual	$12,572	$5,061
Quarterly	$17,452	$7,025
Monthly[a]	$46,539	$18,734
[a]The annual cost for monthly OGI surveys at G&B sites is the annual cost for quarterly surveys in ERG's workbook multiplied by 3 (12 surveys/4 surveys)		

g. The reductions are less and the costs higher in the San Juan basin than the Permian basin due to the differences in gas composition between the basins. The San Juan basin field gas is about 15% by weight VOC while the Permian basin field gas is about 31.8% by weight VOC.

h. As this analysis illustrates, the cost of leak surveys at gathering and boosting stations are significantly higher than estimated by ERG and not justified as currently proposed.

i. For these reasons, NMOGA recommends the frequencies and thresholds be adjusted to better reflect the potential reductions and costs.

2. *Transmission Compressor Stations*

a. In the analysis conducted for NMED, ERG did not include any information or basis for VOC emissions or VOC emission reductions from transmission compressor stations. ERG does state, in their analysis workbook, that they "Used Colorado cost per inspection for the annual cost and the CTG cost effectiveness value for quarterly OGI checks for G&B." for stations with a VOC PTE <25 tpy, and they "Used Colorado cost per inspection for the annual cost. Used the CTG cost effectiveness value for quarterly OGI checks for G&B x a factor of 1.5 because the cost/ton increases as the frequency increases." for stations with a VOC PTE >= 25 tpy.

b. Since there are no estimates of VOC emissions or emission reductions, there is no basis for NMOGA or the EIB to evaluate the efficacy of the 20.2.50.116 NMAC requirements for transmission compressor stations.
c. Given the fact that natural gas handled by transmission compressor stations has been processed and most propane and heavier hydrocarbons (VOC's) removed it is almost certain that potential equipment leak VOC emissions are very low and any reductions from LDAR surveys would be correspondingly very low.
d. The VOC content of typical pipeline natural gas in the US is around 0.8% by weight VOC, contrasted with 15% by weight for produced gas in the San Juan basin and 31.8% by weight for produced gas in the Permian basin.
e. EPA did not include transmission compressor stations in the 2016 CTG because, given the lack of VOCs in the gas handled, there is little to no potential for VOC reductions to be made at them.
f. Based on the EPA 2019 Greenhouse Gas Inventory and the typical composition of pipeline natural gas in the US, the equipment leak emissions of VOC are around 0.12 tpy per transmission compressor station. Reductions from LDAR leak surveys and repair are a fraction of this dependent on the survey frequency.
g. Due to the lack of information to evaluate the appropriateness of the proposed 20.2.50.116 NMAC for transmission compressor stations, the certainty that VOC emissions would be less than 0.1 tpy/station regardless of the inspection frequency, and the extremely high cost of the miniscule potential VOC reductions, NMOGA recommends that leak surveys for transmission compressor stations be reduced as outlined above.

3. ***Gas Processing Plants***
   a. In their analysis, conducted for NMED, ERG does not document or analyze incremental VOC reductions from implementing 20.2.50.116 NMAC at gas processing plants.
   b. ERG inappropriately uses the cost per ton of VOC reduction from the 2016 CTG to analyze the average cost per ton of reduction from gas processing plants. However, the basis for the 2016 CTG LDAR reductions and costs are entirely different than and not reflective of the requirements for LDAR at gas processing plants in 20.2.50.116.
      i. The 2016 CTG's evaluated the incremental reductions and costs of an existing gas plant moving from a Subpart KKK or Subpart VV LDAR program to a Subpart VVa program. The incremental requirements in the 2016 CTG's would be monthly checks for valves and pumps, and periodic checks for connectors based on the percent that are found leaking. If >0.5% of connectors are found leaking, then all need to be checked annually; longer intervals are allowed at lower percentages of leaking connectors.
      ii. In contrast, the requirements in 20.2.50.116 are for quarterly or monthly LDAR surveys of the entire gas processing facility rather than just incremental checks of valves and pumps.
      iii. ERG does acknowledge that most, if not all, gas processing plants in New Mexico are already implementing an LDAR program under Subpart KKK or Subpart VV. ERG also documents some plants subject to the Subpart OOOOa NSPS requirements for LDAR surveys which mirror those in the 2016 CTG's.
      iv. For gas processing plants that are already implementing a Subpart VVa program under NSPS OOOOa, ERG incorrectly assigns zero cost in their analysis. However, there are no exclusions of such plants in 20.2.50.116 NMAC as proposed. NMOGA has recommended a change in the proposed rule that acknowledges compliance with LDAR requirements in Subpart OOOOa, and other NSPS's constitutes compliance with 20.2.50.116 NMAC.
   c. Without documentation of the incremental VOC reductions from implementing the proposed rule requirements at gas processing plants and correct documentation of the cost per ton of VOC reduction, there is no ability for NMOGA or the EIB to evaluate whether the requirements are appropriate or not.
   d. For these reasons, NMOGA has recommended changes which would limit the frequency of LDAR surveys at gas processing plants.

Comment on 20.2.50.116(C)(4)(a): Redline required as calibration procedures vary by type and manufacturer of instrument. This calibration requirement should cite the manufacturer's procedures.

Comment on 20.2.50.116(C)(7)(a): Redline required to align with federal rule. NMOGA finds language around scissor-lifts confusing and potentially asks operators to conduct unsafe work at unsafe heights. This practice is not routine and is done only when necessary, with significant safeguards. These safeguards, such as spotters and shutting in equipment, are generally not factored into cost-benefit and likely results in very little additional emissions reduction. Inspectors are regularly able to find leaks on top of storage tanks from the ground, without risking work at heights. To address these concerns we recommend removing language.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of ~~identifying~~ verifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting the first monitoring under that plan.

(b) 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 the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

Comment on 20.2.50.116(D)(2)(a): Redline required. Notice cannot be provided each time, but we can commit to notice the first time/first use. If the department wants to observe, they can reach out and operators can accommodate that request.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component not otherwise repaired at the time of discovery until the component has been repaired;

(2) leaks shall be repaired within ~~15~~ 30 days of discovery~~, except for leaks detected using OGI, which shall be repaired within seven days of discovery;~~

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

(4) if the leak cannot be repaired within ~~15~~ 30 days of discovery ~~, or within seven days for a leak detected using OGI,~~ without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next planned process unit shutdown~~.~~ and

(5) if the leak cannot be repaired within 30 days of discovery due to shortage of parts or personnel~~-~~ , the leak may be designated "Repair delayed," and must be repaired within 15 days of resolution of such shortage.

Comment on 20.2.50.116(E)(2): Redline required because leak repair time should be consistent regardless of detection method.

Comment on 20.2.50.116(E)(3): Redline required: Verification of repair timeline should be tied to date of repair, not date of discovery.

Comment on 20.2.50.116(E)(5): Redline required due to supply chain restrictions. Below are some commentary and examples.
1. Oil and Gas companies do keep stock of some common sizes and parts for repairs and replacement. However, some fugitive emission components (or their associated parts) are not common stock and must be ordered at the time they are needed. The company is then potentially at the mercy of the distributor or manufacturer for receiving the part.
2. A valve leak was found and when maintenance went to repair, they could not. The valve was broken internally, and the valve was no longer available from the manufacturer (due to age). The piping and valve had to be re-engineered to accept a newer style/size of valve to fix the repair. This took time for Engineering to do and for Operations to implement.
3. Global Pandemic: The COVID-19 global pandemic created many stocking and manufacturing delays for parts across many sectors. Items once easily obtained became harder to source because manufacturers had reduced work.
4. 2021 Polar Vortex: The Winter storm that hit the Midwest and South in mid-February 2021 caused numerous shipping

delays and operational issues for companies in the affected areas. Many companies were working diligently to maintain normal operations in the affected area.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the ~~personnel~~ person(s) performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible ~~flag~~ tag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery;

(ii) ~~signature of the authorized representative~~ name of person(s) who determined that the repair could not be implemented without a process unit shutdown or parts and/or personnel shortages ;

(d) date of successful leak repair;

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

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Manual ~~L~~liquid unloading operations ~~including down-hole well maintenance events~~ resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Manual ~~L~~liquid unloading operations that do not result in the venting of any natural gas are not subject to this part. Within two years of the effective date of this Part, owners and operators of a Natural gas well subject to this Part, must comply with the standards set forth in Paragraph (3) of Subsection B of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for venting of natural gas associated with manual liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices within two years of the effective date of this Part during venting associated with manual liquid unloading to minimize emissions, consistent with well site conditions and good ~~engineering~~ operating practices:

(a) reduce wellhead pressure before blowdown/venting to atmosphere;

(b) monitor manual venting associated with manual liquid unloading in close proximity to the well or via remote telemetry; and

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

(3) The owner or operator of a natural gas well shall employ methodologies to ~~use one of the following methods to~~ reduce emissions during venting associated with a liquid ~~n~~ unloading event. These methodologies may include, but are not limited to:

(a) ~~**(a)** installation and~~ use of a plunger lift

~~**(a)**~~**(b)** use of an automated controls system~~;~~