TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

NMED: Section 20.2.50.1 is a mandatory section for all rules promulgated by New Mexico state agencies, and it provides the official name of the agency issuing the rule. The Board is the issuing agency pursuant to the AQCA.

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. As of the effective date, sources located in the following counties of the state are subject to this Part: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia.

NMED: Section 20.2.50.2 is a mandatory section for all rules promulgated by New Mexico state agencies, and identifies to whom the rule applies: the areas of the State that are subject to, or may become subject to, Part 50. This proposed language should be adopted because it aligns with the language of the AQCA. In accordance with the AQCA, Part 50 establishes emissions standards for oil and gas production and processing sources located in areas of the State within the Board's jurisdiction that, as of the effective date of the rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard (NAAQS) for ozone, as measured by a design value calculated and based on data from one or more Department monitors. Those areas currently include Chaves, Eddy, Lea, Rio Arriba, San Juan, Sandoval, and Valencia. NMED Exhibit 1, p. 4-5.

NMOGA argues that sources in Chaves and Rio Arriba Counties should not be included in Part 50 because the Department has not shown that sources in those counties cause or contribute to ozone concentrations above ninety-five percent of the NAAQS, as measured by Department monitors. IPANM likewise argues that the statute only allows the Board to regulate sources within counties that have ozone monitors located within their boundaries. The Board should reject these arguments because they run contrary to the language and intent of the statute. Modeling clearly demonstrated that oil and gas sources in the specified counties contributed to ozone levels at the monitors that were registering concentrations exceeding ninety-five percent of the NAAQS. Mr. Baca testified that ozone monitors in the state are located according to EPA regulations under the CAA. These monitor locations are associated with Air Quality Control Regions (AQCR), not counties. Thus, the monitor located in Hobbs measures ozone concentrations for the AQCR that encompasses Chaves County, and the monitor located at Navajo Lake measures ozone concentrations for the AQCR that includes the part of Rio Arriba County encompassing the San Juan Basin. Tr. Vol. 1, 297:16 – 309:16.

The Board's statutory directive under the AQCA is not to regulate sources in "counties;" rather it must regulate sources in any "area" of the state where ozone levels exceed ninety-five percent of standard. The Department proposed to delineate the scope of Part 50 by county in order to facilitate compliance with the rule because counties have well-established and commonly understood boundaries. Tr. Vol. 1, 305:23 – 306:3. It would be far more difficult for owners and operators of affected sources to determine applicability of the rule if the scope of the rule was based on Air Quality Control Regions. The counties identified in Section 20.2.50.2 contain the majority of oil and gas sources in the major producing basins in the State. If the Board were to exclude sources located in Chaves and Rio Arriba County, it would leave unregulated significant emissions of ozone precursors from oil and gas sources under its jurisdiction, thereby contravening the express intent of the statute, which is to reduce emissions of NOx and VOCs to provide for attainment and maintenance of the NAAQS. Tr. Vol. 1, 309:5-16. NMED Closing Argument pp. 39-41.

<u>IPANM proposes additional language</u>**:**

SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations <u>based on data submitted by the department to EPA's Air Quality System</u> that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors…..

Kinder Morgan proposes replacing "are causing or contributing" to "have":

SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this Part or anytime thereafter, ~~are causing or contributing to~~ have ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors….

NMOGA, IPANM, and Kinder Morgan propose to delete Chaves and Rio Arriba Counties:

NMOGA: Section 74-2-5.C is clear that the Board's authority to adopt regulations is limited to those areas of the state exceeding 95 percent of the primary NAAQS. Rio Arriba County does not have a "design value" exceeding 95% of the NAAQS. The Department's witnesses conceded this point. Baca testimony, Tr. 1:301:17-21. The Department has now changed its position to argue that because some place in the air quality control region has a design value that exceeds 95%, the whole air quality control region and any county partially within it should have that design value. That is not how design values work. Having chosen the "county" as a basis for its proposed rule, the Department must justify its proposal on that basis. The evidence shows that the only monitor in Rio Arriba County has a design value less than 95% of the ozone NAAQS and that concentrations are trending downward.

Similarly, Chaves County has no design value and should not be included in Part 50. Tr. 1:191:12-18. The Department argued that it "contributes" to the ozone problem, but the "contribution" aspect of Section 74-2-5.C goes to the types of sources contributing to the ozone problem and does not authorize regulation of those sources unless they are in an area of the state exceeding 95% of the NAAQS. Section 74-2.5.C sets forth a two-step process before regulations may be adopted: In step 1, the Board "determines that emissions from sources … cause or contribute to ozone concentrations in excess of ninety-five percent" of the primary ozone NAAQS. In step 2, if this finding is made, then the "board … shall adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance" of the ozone NAAQS. But "rules adopted pursuant to this subsection *shall be limited to sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent*" of the ozone NAAQS. *Id.* Containing sources that "cause or contribute" is simply irrelevant to the question of whether Chaves County "exceeds" 95% of the NAAQS. The record does not support applying the rule to Chaves or Rio Arriba County. [See NMOGA's proposed SOR 44-50]

<u>IPANM:</u> NMED proposed that the rule should be applied to sources in areas of the state that exceed ninety-five percent of the NAAQS for ozone and areas where emission cause or contribute to those ozone levels. IPANM supported limiting the Ozone Rule to those areas of New Mexico with a design value that is greater than 95 percent of the federal ozone NAAQS. IPANM Ex. 2 at 5 (Davis Direct). Further, IPANM believes it should be the Board's responsibility to add or delete areas subject to the regulations, based on future monitored ozone concentrations. Id.; IPANM Ex. 1 at 1:16-24. NMED testified that the current rule outlines the counties that are subject to Part 50, as well as a process and timeline for NMED to petition the Board to incorporate new areas.

NMOGA testified that the current counties that should be included in this rule would be Dona Ana, Eddy, Lea, Sandoval, San Juan, and Valencia. Tr. Vol. 2, 630:20-23 (Smitherman). NMOGA supported NMED in creating a process for areas or counties that are added in the future to the public has an opportunity "to challenge and understand how [the] criteria has been met." Tr. Vol. 2, 631:1-10 (Smitherman). IPANM agreed with NMOGA's testimony. Tr. Vol. 2, 638:12-16 (R. Davis).

IPANM objects to the inclusion of Chaves and Rio Arriba Counties. Those counties did not have ambient ozone concentrations in excess of 95% of the ozone NAAQS. IPANM disagreed that emissions in those counties caused or contributed to ozone concentrations in excess of 95% of the NAAQS in other counties or areas of the state. Tr. Vol. 2, 638:12-16 (R. Davis).

[See also IPANM's Closing Argument, pp. 4-15 and proposed SOR for more regarding relative source contribution, the impossibility of comparing relative ozone benefits based on the modeling, and emission inventory uncertainties, SOR 40-91.]

Kinder Morgan: Section 74-2-5.C of the Act is the Board's authority for this rulemaking, and is unambiguous. It requires that, if the Board determines that sources of emissions within the Board's jurisdiction cause or contribute to ozone concentrations exceeding 95% of NAAQS, the Board must then adopt a plan, including rules, to control ozone precursor (i.e., NOx and VOCs) emissions in order to attain and/or maintain the ozone standard. The Act is clear, however, that the only sources that can be subject to any such ozone precursor rules are sources located in an area of the State in which ozone concentrations actually exceed 95% of NAAQS. The Department evidently disagrees with this interpretation. The Department's Proposed Rules will apply to "sources located within areas of the state under the board's jurisdiction, that, as of the effective date of this Part or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the [NAAQS] for ozone, as measured by a design value calculated and based on data from one or more department monitors." By the Department's own testimony, however, the design value for Rio Arriba is currently below 95% of NAAQS. See NMED Amended Ex. 4 (Sept. 20, 2021), at 6. Further, there is no ozone monitor in Chaves County, so its design value is unknown. Id. at 4.

The Department's technical witness, Mr. Baca, explained that, "the stated purpose of the regulations adopted by the Board under the [Act] is to provide for the attainment and maintenance of the [ozone] standard. To achieve this, the purpose of the statute directs the Board to regulate sources within areas of the state that cause or contribute to ozone concentrations exceeding 95 percent of the NAAQS. The statute does not say that the regulations can only apply to counties with monitors showing concentrations exceeding 95 percent, so, logically, the boundaries of any designated nonattainment area would not be restricted to county lines or counties with monitors." Hearing Transcript, Vol. 1, 299:20–300:6. Kinder Morgan does not dispute that the statute does not prescribe how ozone concentrations are to be measured to determine where ozone precursor rules may apply. The Department, however, has chosen to determine applicability of the Proposed Rules based specifically on "a design value calculated and based on data from one or more department monitors." Applying the Department's chosen methodology to the plain language of the statute, the Proposed Rules cannot apply to sources in Rio Arriba or Chaves counties.

When counsel for NMOGA asked Mr. Baca about his interpretation of statute, however, Mr. Baca testified that the second sentence of Section 74-2-5.C does not establish any geographic limit on the areas in which the Board's ozone precursors rules may be applied. Hearing Transcript, Vol. 1, 319:24–320:8. Rather, he explained, that sentence "just says it's limited to sources with emissions, within any area of the state where ozone concentrations exceed. So it could be any emissions anywhere in the state that – within the area of the state that the ozone concentrations exceed 95 percent, . . . So the rules are limited to the sources within the Department's jurisdiction that can – within areas of the state where ozone concentrations are monitored at 95 percent. So the rule can apply to any part of any area of the state where monitoring – and reasonably be attributed as exceeding 95 percent of the standard." Id. at 319:8–320:25.

The Department appears to take the position that, so long as emissions from a source can reasonably be attributed to ozone concentrations in excess of 95% of NAAQS anywhere in the state of New Mexico, such sources can be made to comply with the Proposed Rules. This interpretation is in direct conflict with the plain language of the statute and should be rejected. See N.M.S.A. § 74-2-5.C. ("Rules adopted pursuant to this subsection shall be limited to sources of emissions within the area of the state where the ozone concentrations exceed ninety-five percent of the primary national ambient air quality standard."). [See Kinder Morgan's Closing Argument pp. 25-27 for more detail.]

A. If, at any time after the effective date of this Part, sources in any other area(s) of the state not previously specified are determined to be causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated by the U.S. Environmental Protection Agency based on data from one or more department monitors, the department shall petition the Board to amend this Part to incorporate the sources in those areas.

(1) The notice of proposed rulemaking shall be published no less than one-hundred and eighty (180) days before sources in the affected areas will become subject to this Part, and shall include, in addition to the requirements of the Board's rulemaking procedures at 20.1.1.301 NMAC:

(a) a list of the areas that the department proposed to incorporate into this Part, and the date upon which the sources in those areas will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for throughout this Part, for

sources within the areas subject to the proposed rulemaking to come into compliance with the provisions of this Part.

(2) In any rulemaking pursuant to this Section, the Board shall be limited to consideration of only those proposed changes necessary to incorporate other areas of the state into this Part.

NMED: The Department proposes to include language offered by NMOGA that requires a rulemaking to incorporate sources in other areas of the state, specifies that the effective date of such changes will be at least 180 days from the date of publication of the notice of rulemaking, and specifies the type of information that must be included in proposed revisions for a rulemaking to add sources in other areas of the State. NMED Rebuttal Exhibit 1, p. 2. The Department also proposed language in this Subsection limiting the rulemaking required under Section 20.2.50.2 to only those proposed changes and supporting evidence necessary to incorporate other areas of the State. This language is necessary to ensure that the rulemaking does not become a vehicle for anyone to attempt to propose changes to other sections of Part 50, thereby expanding the scope of the rulemaking and bogging down the Department's and the Board's resources. Id.

Kinder Morgan: Kinder Morgan supports the Department's addition of a clear process by which new areas of New Mexico can become subject to the Proposed Rules following the effective date. For additional discussion of this issue, see the Non-Technical Statement, at pages 11–15.

IPANM proposes to insert similar language that NMED accepted from NMOGA:

A. If, at any time after the effective date of this Part, any counties or in area(s) of counties not previously specified in the state is determined to be causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard…...

B. Once a source becomes subject to this Part based upon its potential to emit, all requirements of this Part that apply to the source are irrevocably effective unless the source obtains a federally enforceable limit on the potential to emit that is below the applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.

[20.2.50.2 NMAC – N, XX/XX/2021]

NMED: Subsection B of Section 20.2.50.2 specifies that once a source becomes subject to Part 50, the requirements of Part 50 are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in Part 50. The Board should adopt this proposal because it ensures that the emissions reductions achieved by Part 50 will be permanent.

IPANM proposes to delete the word "irrevocably":

B. Once a source becomes subject to this Part based upon its potential to emit, all requirements of this Part that apply to the source are ~~irrevocably~~ effective unless the source obtains a federally enforceable limit on the potential to emit that is below the applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply.

0.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.3 is a mandatory section for all rules promulgated by New Mexico state agencies and identifies the enabling legislation that authorizes the issuing agency to promulgate the rule. Section 20.2.50.3 lists the statutory authorities pursuant to which the Board is authorized to adopt Part 50. The Board should adopt this proposal for the reasons stated in NMED Exhibit 1, pp. 4-5 and NMED Exhibit 32, pp. 12-13.

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.4 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides the length of time the rule is intended to be enforceable. The Department proposes for Part 50 to be permanently in effect from the effective date established in Section 20.2.50.5. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 13.

20.2.50.5 EFFECTIVE DATE: Month XX, 2022, except where a later date is specified in another Section. [20.2.50.5 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.5 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides the date the rule goes into effect. This date depends on when the final rule is published in the New Mexico Register. The Board should adopt this proposal for the reasons in NMED Exhibit 32, p. 13.

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, compression, and transmission sources. [20.2.50.6 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.6 is a mandatory section for all rules promulgated by New Mexico state agencies, and provides a statement describing the purpose of the rule and its intended effect.

Kinder Morgan desires further clarification in the SOR: It is undisputed that this rulemaking is focused on achieving emissions reductions from oil and gas sources that emit VOC and NO_x. It is also undisputed that methane is not an ozone precursor. While Kinder Morgan does not contest that reducing VOC and NO_x emissions may result in the co-benefit of reducing methane emissions, no portion of 20.2.50 NMAC (nor the implementation thereof) can be predicated on reducing methane emissions – including cost-benefit analyses. Based on our review of the hearing transcript and our participation in the hearing, we do not believe this issue is in dispute; however, it is important that the Board reiterate this position in its Statement of Reasons to add clarity and certainty during implementation for any interested stakeholder that is not party to this rulemaking.

The proposed SOR:

> In adopting these rules, it is the Board's objective to adopt standards to control emissions of oxides of nitrogen (NOx) and volatile organic compounds (VOCs). The Board recognizes that a co-benefit of these standards will be a reduction in methane emissions; however, the Board's rules are limited to regulating emissions of VOC and NOx from the subject sources. This approach is consistent with the Board's statutory authority under N.M.S.A. § 74-2-5.C.

CEP on the consideration of co-benefits: Industry parties have suggested that the EIB may not consider the co-benefits of reducing ozone precursors in determining what combination of measures to adopt in the rule to meet the state's ozone control obligations. For example, the parties objected (unsuccessfully) to any evidence that was related to reduction of methane on the theory that such evidence was improper because it was not related to achieving and maintaining the NAAQS for ozone, but rather is a greenhouse gas that contributes to climate change. 8 Tr. 2344:15-2350:23 (hearing officer consideration of the IPANM objection).

The industry parties' assertion flies in the face of the plain language of the AQCA, which authorizes the EIB to "give weight it deems appropriate" to multiple factors in this rulemaking, including costs to industry, but also explicitly including health, welfare, and the public interest. NMSA 1978, § 74-2-5.F.

Consideration of both indirect costs and co-benefits in rulemaking is widely mandated by courts. See e.g., *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin*., 538 F.3d 1172, 1198-1200 (9th Cir. 2008) (holding a National Highway Traffic Safety Administration rule unlawfully arbitrary for failing to consider greenhouse gas benefits of fuel economy standards, concluding this "put a thumb on the scale by undervaluing the benefits and overvaluing the costs."). [See CEP Closing Argument, pp. 6-10 for full argument on the Board's authority to consider co-benefits.]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Auto-igniter" means a device that automatically attempts to relight the pilot flame of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

NMED: The definition of "Auto-igniter" in Subsection A of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.5. The term is used in Section 115. The Department made revisions to its original proposal based on comments from NMOGA. *See* NMED Rebuttal Exhibit 1, p. 4. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 14, and NMED Rebuttal Exhibit 1, p. 4.

B. "Bleed rate" means the rate in standard cubic feet per hour at which gas is continuously vented from a pneumatic controller.

NMED: The definition of "Bleed rate" at Subsection B of Section 20.2.50.7 was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. This term is used in Section 122. The Department revised its original definition to align with federal and other state interpretations of the term based on comments from NMOGA, as described in NMED Rebuttal Exhibit 1, p. 4. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 14, and NMED Rebuttal Exhibit 1, p. 4.

C. "Calendar year" means a year beginning January 1 and ending December 31.

NMED: The definition of "Calendar year" in Subsection C of Section 20.2.50.7 implements the commonly accepted interpretation of a calendar year. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 14.

D. "Centrifugal compressor" means a 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 a mechanical rotating vane or impeller. A screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

NMED: The definition of "Centrifugal compressor" in Subsection D of Section 20.2.50.7 was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The term is used in Section 114. The Board should adopt this proposal for the reasons stated in NMED Ex. 32, p. 14.

E. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere during operation.

NMED: The definition of "Closed vent system" in Subsection E of Section 20.2.50.7 was derived in part from language in Colorado Reg. 7, Section I.J, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5411a(a). The term is used in Section 115. The Department has proposed adding "during operation" at the end of the definition to clarify the intent of this provision as explained by Ms. Kuehn at the hearing. Specifically, Ms. Kuehn testified that the Department recognizes that during maintenance there will be some emissions associated with venting, and that the requirement reflects the expectation that during normal operations there will be no loss of VOC to the atmosphere. *See* Tr. Vol. 6, 1888:7

– 1889:3. The Board should adopt this proposal for the reasons stated above and in NMED Exhibit 32, p. 14. NMOGA had proposed to strike “no” and replace with “minimal,” but it supports the current proposal with “during operation” at the end. [See also NMOGA SOR 51.]

F. “Commencement of operation” means for an oil and natural gas well site, the date any permanent production equipment is in use and product is consistently flowing to a sales line, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

NMED: The definition of “Commencement of operation” in Subsection F of Section 20.2.50.7 describes when operation of a production well may be presumed to have begun, and was derived in part from Colorado Reg. 7, Section I.B.7. NMOGA proposed to strike “but no later than the end of well completion operation.” The Department did not agree with this revision because the Department’s proposed definition is consistent with Colorado Reg. 7, and is consistent with the term as used in Part 50. The Board should adopt the Department’s proposal for the reasons stated in NMED Exhibit 32, pp. 14-15 and NMED rebuttal Exhibit 1, p. 5.

NMOGA proposes to strike from **“but no later than the end of well completion operation” at the end of Section F:** Mr. Smitherman testified that there can be a significant time delay between when a first well being served by a well production facility is completed and when it begins normal production to sales. The phrase “but no later than the end of well completion operations” should therefore be struck; Smitherman rebuttal, NMOGA Ex. 41:3:12-28. Mr. Smitherman testified that the Waste Rule by the Oil Conservation Commission may extend the delay between when a well is completed and when it begins production. By removing the last sentence, the rule will be applicable the entire time that a facility is actually producing oil, gas, or produced water production.

G. “Component” means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water, or methanol.

<u>NMED:</u> The definition of "Component" in Subsection G of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.10. No parties commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 14.

H. "Connector" means flanged, screwed, or other joined fittings used to connect pipeline segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipeline to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

<u>NMED:</u> The definition of "Connector" in Subsection H of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.11. No parties commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 14.

I. "Construction" means fabrication, erection, or installation of a stationary source, including but not limited to temporary installations and portable stationary sources, but does not include relocations or like-kind replacements of existing equipment.

<u>NMED:</u> The definition of "Construction" at Subsection I of Section 20.2.50.7 describes the types of activities that constitute construction. This definition was taken from the Board's regulations for air quality construction permits at 20.2.72 NMAC. The Department agreed with NMOGA's proposed revision to exclude relocations and like kind replacements of existing sources from the definition, but disagreed with the proposal to exclude replacements, temporary installations and portable stationary sources because the Department intended to include temporary and portable equipment under Part 50. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, p. 15; NMED Rebuttal Ex. 1, p. 4. [See also NMOGA SOR 56.]

<u>GCA</u>: supports the proposed definition of "construction" in 20.2.50.7(I). The relocation of an existing compressor engine, where the engine is not otherwise rebuilt or reconstructed, should not be considered "construction" of that engine, and should not provide a basis for converting the engine from an existing engine into a new engine that is subject to the proposed rule's more-stringent emissions standards for new engines.

GCA Exhibit 12 (Dutton Direct) at 13; GCA Exhibit 9 (Sheldon Direct) at 19. [See also GCA proposed SOR 1-5 and 32-38.]

J. "Control device" means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices may include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part. A VRU or other equipment used primarily as process equipment is not considered a control device.

NMED: The definition of "Control device" in Subsection J of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Part A, Section II.A.7. The term is used in Section 115. As part of its final proposal, the Department has included clarifying language that a VRU or other equipment that is used primarily as process equipment is not considered a control device to address NMOGA's earlier concerns. The term "Vapor Recovery Unit" or "VRU" is well understood by the regulated industry, and VRUs used to comply with the emission standards of Part 50 are subject to the relevant requirements under this Part. While it is correct that VRUs can be used as both a process and a control device, NMED did not intend to regulate VRUs used as process equipment under Part 50; rather, only VRUs that are utilized to meet the emission standards of this Part are subject to the requirements of 20.2.50.115. In each Section that establishes an emission standard, the owner or operator must identify the control device being used to comply with the emission standards; there is already an affirmative record if a VRU is being used as a control device to comply with this Part. No additional definitions or documentation are necessary to make this distinction. Ms. Kuehn confirmed that by including VRUs in the definition of control device, NMED was not trying to adopt a global determination that all VRUs are control devices. *See* Tr. Vol. 6, 1889:6-19. NMED only intended to regulate VRUs that are used to comply with the emission standards of Part 50, and did not intend to exempt VRUs unless they are primarily used as process equipment. *See* NMED Rebuttal Exhibit 1, pp. 5-6. [NMOGA proposed no additional edits. NMOGA SOR 52.]

K. "Department" means the New Mexico environment department.

NMED: The definition of “Department” in Subsection M of Section 20.2.50.7 is necessary to define which agency is referred to in Part 50.

L. “Design value” means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

NMED: the term “design value” is used in Section 20.50.2, Scope, and was added by the Department based on a proposal by IPANM. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 6.

NMOGA proposes to add **“at an ambient ozone monitor”** at the end of the sentence: The definition of “Design Value” is necessary to clarify section 20.2.50.2 NMAC, which uses the term “design value” to describe how the Department evaluates which counties exceed 95% of the primary ozone standard. Tr. Mr. Baca, 1:317:4-8. Based on witness testimony, the Board should find that design values are calculated based on monitoring data obtained from monitoring stations. Mr. Ahr, witness for NMED, testified, “The NAAQS is met at an ambient air monitoring site when the three-year average of the fourth-highest daily maximum 8-hour average ozone concentration, or the design value, is less than” the standard. Tr. 1:187:18-25. Mr. Ahr also confirmed that “those counties without a monitoring station don’t have . . . design values calculated.” Tr. 1:193:2-6. To clarify the nature of how design values are determined, the Board should find that the phrase “at an ambient ozone monitor” should be added to the definition.

M. “Downtime” means the period of time when equipment is not in operation.

NMED: This definition was derived in part from Merriam-Webster dictionary. The Department made revisions to its original proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 16, and NMED Rebuttal Exhibit 1, p. 6.

NMOGA proposes to replace **“not in operation”** with **“inoperable”**: The adjustment is based on testimony that downtime should include only time the equipment is inoperable and not when it is shutoff because the controlled process unit is not operating. Bisbey-Kuehn testimony, Tr. 4:1107:1-8.

The CEP and Oxy propose additional definitions related to their proposals in Sections 123 and 127; see discussions below those sections:

N. "Drilling" or "drilled" means the process to bore a hole to create a well for oil and/or natural gas production.
O. "Drill-out" means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore cleanup.
R. "Flowback" means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.
S. "Flowback vessel" means a vessel that contains flowback.

N. "Enclosed combustion device" means a combustion device where waste gas is combusted in an enclosed chamber solely for the purpose of destruction. This may include, but is not limited to an enclosed flare or combustor.

NMED: The definition of "Enclosed combustion device" in Subsection N of Section 20.2.50.7 is based on common usage of the term in oil and gas regulatory provisions. *See, e.g.*, NSPS Subpart OOOOa, 40 CFR § 60.5412(d)(1). The term is used in Section 115. The definition in Part 50 was developed during rule drafting based on the knowledge and experience of NMED technical staff. The Department made revisions to its initial proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 16, and NMED Rebuttal Exhibit 1, p. 7.

O. "Existing" means constructed or reconstructed before the effective date of this Part.

NMED: The definition of "Existing" in Subsection O of Section 20.2.50.7 is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is "existing" or "new". (NMOGA's earlier concern has been mooted by NMED's deletions following the word "Part.") The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 16-17. [See also NMOGA SOR 55.]

P. "Gathering and boosting station" means a facility, including all equipment and compressors, located downstream of a well site that collects or moves natural gas prior to the inlet of a natural gas processing plant; or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed; or collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation. Gathering and boosting stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

<u>NMED:</u> The definition of "Gathering and boosting station" at Subsection P of Section 20.2.50.7 was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The term is used in Section 20.2.50.111. The Department agreed with revisions to this definition proposed by NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 9, 17, and NMED Rebuttal Exhibit 1, p. 16.

Q. "Glycol dehydrator" means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

<u>NMED:</u> The definition of "Glycol dehydrator" in Subsection Q of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.15. This term is used in Section 118. No parties commented in this definition. The Board should adopt this proposal for the reason stated in NMED Exhibit 32, p. 15.

R. "High-bleed pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.

<u>NMED:</u> The Department is proposing to add a definition of "High-bleed pneumatic controller" in Subsection R of Section 20.2.50.7 based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. This term is used in Section 122. The Department agrees that this definition helps provide clarity by differentiating between controller types. The Board adopts this proposal for the reasons provided in the industry parties' testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn's testimony at Tr. Vol. 7, 2024:22 – 2025:5.

The CEP and Oxy propose additional definitions related to their proposals in Sections 123 and 127; see discussions below those sections:

W. "Hydraulic fracturing" means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

X. "Hydraulic refracturing" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

S. "Hydrocarbon liquid" means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons. Hydrocarbon liquid does not include produced water.

NMED: The definition of "Hydrocarbon liquid" in Subsection S of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.16. The term is used in Section 120. The Department made revisions to its original proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 17, and NMED Rebuttal Exhibit 1, p. 8. [See also NMOGA SOR 57.]

T. "Inactive well site" means a well site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

NMED: The Department proposes this definition as part of its support for the joint proposal of the EDF, CAA, CPP/NAVA (collectively, the "eNGOs") and Oxy USA at Subparagraph (g) of Paragraph (3) of Subsection C of 20.2.50.116. The Department refers the Board to the testimony and findings from those parties for supporting information on this definition. [See below in discussion of Section 116.]

U. "Injection well site" means a well site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

NMED: The Department proposes this definition as part of its support for the joint proposal of the eNGOs and Oxy USA at Paragraph (9) of Subsection C of 20.2.50.116. The Department refers the Board to the testimony and findings from those parties for supporting information on this definition.

V. “Intermittent pneumatic controller” means a pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas above de minimis amounts to the atmosphere as part of the actuation cycle.

NMED: The Department is proposing to add a definition of “Intermittent pneumatic controller” in Subsection V of Section 20.2.50.7 based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. This term is used in Section 122. The Department agrees that this definition helps provide clarity by differentiating between controller types. The Board should adopt this proposal for the reasons provided in the industry parties’ testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn’s testimony at Tr. Vol. 7, 2024:22 – 2025:5.

W. “Liquid unloading” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

NMED: The definition of “Liquid unloading” in Subsection W of Section 20.2.50.7 was derived from general information on EPA’s Natural Gas STAR website and the EPA publication “Options for Removing Accumulated Fluid and Improving Flow in Gas Wells” (NMED Exhibit 44). The term is used in Section 117. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 17.

X. “Liquid transfer” means the unloading of a hydrocarbon liquid from a storage vessel to a tanker truck or tanker rail car for transport.

NMED: The definition of “Liquid transfer” in Subsection X of Section 20.2.50.7 was derived from general information from EPA’s website and EPA’s AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, Section 5.2.2 (NMED Exhibit 43). The term is used in Section 120. The Department made revisions to its initial proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 17, and NMED Rebuttal Exhibit 1, p. 8.

Y. “Local distribution company custody transfer station” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

NMED: The definition of “Local distribution company custody transfer station” at

Subsection Y of Section 20.2.50.7 was derived from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The term is used in Section 20.2.50.111. No party submitted comments on this proposed definition. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 17-18.

Z. "Low-bleed pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

NMED: The Department is proposing to add a definition of "Low-bleed pneumatic controller" in Subsection Z of Section 20.2.50.7 based on comments and testimony from NMOGA, IPANM, and GCA. This definition is derived from Colorado Reg. 7, Section III. This term is used in Section 122. The Department agrees that this definition helps provide clarity by differentiating between controller types. The Board should adopt this proposal for the reasons provided in the industry parties' testimony, NMED Rebuttal Exhibit 1, pp. 8-9, and Ms. Kuehn's testimony at Tr. Vol. 7, 2024:22 – 2025:5.

AA. "Natural gas-fired heater" means an enclosed device using a 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.

NMED: The definition of "Natural gas-fired heater" in Subsection AA of Section 20.2.50.119 was derived in part from Colorado Reg. 7., Part E, section II.A.3.p. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 18.

BB. "Natural gas processing plant" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, 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.

NMED: The definition of "Natural gas processing plant" at Subsection BB of Section 20.2.50.7 was derived from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The term is used in Section 20.2.50.111. No party submitted comments on this definition. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 18.

CC. “New” means constructed or reconstructed on or after the effective date of this Part.

NMED: The definition of “New” in Subsection CC of Section 20.2.50.7 is required because the applicability of numerous requirements and timeframes in Part 50 is based on whether a source is “existing” or “new”. No parties commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 18.

DD. “Non-emitting controller” means a device that monitors a process parameter such as liquid level, pressure, or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.

<u>NMED:</u> The Department proposed to add a definition of “Non-emitting controller” in Subsection DD of Section 20.2.50.7 based on comments from NMOGA. This term is used in Section 122. This definition establishes the meaning of the term and the Department’s intended use of the term in Part 50. The Board should adopt this proposal for the reasons stated in the NMOGA’s testimony and NMED Rebuttal Exhibit 1, pp. 8-9.

EE. “Occupied area” means the following:

(1) a building or structure used as a place of residence by a person, family, or families, and includes manufactured, mobile, and modular homes, except to the extent that such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes;

(2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities;

(3) five-thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours: and

(4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or similar place of outdoor public assembly.

<u>NMED:</u> The Department proposes this definition as part of its support for the joint proposal of the eNGOs and Oxy USA at Subparagraph (3) of Paragraph (3) of Subsection C of Section 20.2.50.116. The Department refers the Board to the testimony and findings from those parties for supporting information on this definition. [See the discussion below in Section 116.]

NMOGA proposes changes:

(4) an outdoor venue or recreation area used as a place of outdoor public assembly, such as a playground, permanent sports field, amphitheater, or similar place ~~of outdoor public assembly~~. Outdoor venue or recreation area does not include areas normally used for dispersed recreation, such as non-developed areas of national forests, parks, or similar reserves.

NMOGA proposes its language to limit the scope of the vague term "recreation area," which is sometimes used to cover national forests, parks and similar areas of dispersed recreation, which is different from places of concentrated gathering suggested by the listed activities. If "recreation area" is left in place and not limited, argument could be made that most of New Mexico is an occupied area. On Day 8 of the hearing, Mr. Smitherman announced NMOGA's willingness to conduct weekly AVOs and quarterly OGI or Method 21 surveys. Tr. 8:2708:15-25 – 2712:1-9. Per the Board's request, Mr. Smitherman and NMOGA submitted proposed language. NMOGA Exhibit 64. In that proposal, Mr. Smitherman proposed striking the word "recreation area." NMOGA Exhibit 64:1:23. These changes are consistent with Mr. Smitherman's testimony. [See also NMOGA SOR 58.]

FF. "Operator" means the person or persons responsible for the overall operation of a stationary source.

NMED: The definition of "Operator" in Subsection FF of Section 20.2.50.7 was derived in part from the Clean Air Act at 42 U.S.C Section 7411. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 19.

GG. "Optical gas imaging (OGI)" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

NMED: The definition of "Optical gas imaging (OGI)" in Subsection GG of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.17, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5397a. The term is used in Section 116. No parties commented in this proposal. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 19.

HH. “Owner” means the person or persons who own a stationary source or part of a stationary source.

NMED: The definition of “Owner” in Subsection HH of Section 20.2.50.7 was derived in part from the Clean Air Act at 42 U.S.C Section 7411. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 19.

IPANM offers a definition of “ozone precursor” as a non-substantive clarification:

“Ozone precursor” means nitrogen oxides (NOx) or volatile organic compounds (VOC).

II. “Permanent pit or pond” means a pit or pond used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

NMED: The definition of “Permanent pit or pond” in Subsection II of Section 20.2.50.7 was derived in part from the New Mexico Oil Conservation Commission’s regulations at 19.15.17 NMAC. The term is used in Section 126. The Department made revisions to its initial proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 19, and NMED Rebuttal Exhibit 1, p. 8.

JJ. “Pneumatic controller” means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

NMED: The definition of “Pneumatic controller” in Subsection JJ of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section III.B.10. This term is used in Section 122. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 19, and NMED Rebuttal Exhibit 1, pp. 8-9.

KK. “Pneumatic diaphragm pump” means a positive displacement pump powered by pressurized 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.

NMED: The definition of "Pneumatic diaphragm pump" in Subsection KK of Section 20.2.50.7 was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. This term is used in Section 122. The Department proposed revisions to this definition based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 19-20, and NMED Rebuttal Exhibit 1, p. 9.

IPANM offers a definition of "portable stationary source" as a clarification:

"Portable stationary source" means a source that can be relocated to another operating site with limited dismantling and reassembly.

[IPANM has deleted the last sentence of NMED's proposed definition of "stationary source" at YY and moved it here.]

LL. "Potential to emit (PTE)" 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 the 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 federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

NMED: The definition of "Potential to emit (PTE)" at Subsection LL of Section 20.2.50.7 was derived from the Board's air quality operating permit regulations at 20.2.70 NMAC. The term is used in Section 20.2.50.111. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 20, and NMED Rebuttal Exhibit 1, p. 18.

[NMOGA's earlier edits in this section are not part of its final proposal.] NMED did not agree that the potential to emit can be reduced by any limit other than a federally enforceable limit. Federally enforceable limits include established standards of enforceability that other state, local, or tribal authorities do not necessarily include. It is the Department's intent that only federally enforceable limits can be used to reduce PTE under Part 50. *See* NMED Rebuttal Exhibit 1, p. 18.

WEG proposed changes to the definition of PTE that would include emissions from "non-mobile source" at a well site prior to commencement of operations. The Department opposed this proposal. Mr. Baca testified that WEG's proposal is consistent with the definition used in the Department's permitting programs, which are based on federal regulations at 40 C.F.R. Sections 52.21(B)(4), 51.165(a)(1)(iii), and 51.166(b)(4). Contrary to the testimony of WEG witness Jeremy Nichols, NMED does not issue "drilling" permits for wellhead sites; that is the jurisdiction of the New Mexico Oil Conservation Division. In addition, the activities and emissions (waste) associated with the drilling of wells are also within the jurisdiction of the OCD. After the well is drilled, NMED is responsible for regulating the equipment located at the well site associated with the production of oil and gas. In effect, WEG's proposal requests that the department expand its jurisdiction to include activities regulated by OCD, but WEG offered no emissions information indicating the impact of such a change. It is unclear from Mr. Nichols' testimony what equipment should be included in this calculation. The term "non-mobile" not defined in the Clean Air Act, and it is unclear what equipment would be included. WEG's testimony did not provide any equipment-specific information, or any data regarding emissions from these undefined source types. Thus, Mr. Baca testified that the Department has no way of determining what emissions may occur from such equipment or if such emissions are ozone precursors. NMED Rebuttal Exhibit 22 (Rebuttal Testimony of M. Baca), p. 2.

The report cited in Mr. Nichol's testimony did not undergo peer review and was not published in any scientific journal such that it could be relied upon credible information on which the Board can base its decisions. The methods by which the data was collected and the analysis was performed are not detailed in any way, nor was a reasoned conclusion presented as to how the data supports the report's conclusion that "35% or more of assessed wellhead facilities were constructed prior to being permitted by NMED". Thus, these claims are entirely unsubstantiated, and should not be relied upon by the Board as a basis for adopting WEG's proposal. *Id.* at 2-3. The Board should reject WEG's proposed changes to the definition of "Potential to emit" for these reasons.

<u>WEG proposes a final additional sentence:</u>

"For wellhead sites, calculation of PTE shall include non-mobile source emissions that may occur prior to commencement of operation."

Guardians proposes to include a sentence in the definition of “potential to emit” to clarify that air contaminants, including ozone precursors, emitted from stationary sources at oil and gas wellhead sites are subject to NMED regulation and must be reported and included in the calculation of PTE. Oil and gas well drilling and well completion are the initial processes that occur in the chain of oil and gas production, transmission, and distribution. Air contaminants, including ozone precursors, are typically emitted during this phase of oil and gas production from stationary sources, such as the wellbore. Although the IPANM’s witness, Mr. Blewitt, attempted to minimize the emission of air pollution at the wellhead site, nothing in his testimony or in the law exempts emissions released from stationary sources during wellhead site construction from being reported to NMED and controlled pursuant to the AQCA. TR5 1324: 23-25, 1325: 1.

A primary impetus for Guardians’ proposal was a report titled Impacts of Oil and Gas Drilling on Indigenous Communities in New Mexico’s Greater Chaco Landscape (“Chaco Report”), produced in collaboration with the UCLA Institute of the Environment and Sustainability. The Chaco Report identifies examples of oil and gas operators in New Mexico’s San Juan Basin drilling wells prior to obtaining an air quality permit. See WG Exh. 21; see also TR4 1134: 2-25, 1135: 1-14. In other words, the report found that for some oil and gas facilities a gap existed between construction of the wellhead site and the issuance date of the air quality permit for that facility, in which air pollutants may be emitted but not otherwise accounted for in air quality permits. WG Exh. 21 at 16. Absent an air quality permit, facilities that emit ozone precursors during the drilling of oil and gas wells, for example, are uncontrolled, unregulated, and represent a cost to air quality and public health that is paid for by New Mexicans, instead of by operators. While the Chaco Report did not evaluate New Mexico oil and gas facilities statewide for this gap in air quality permitting, it is unlikely the gap would exist only in the San Juan Basin, especially considering testimony from NMED’s witness, Cindy Hollenberg. Ms. Hollenberg explained that the Department has identified widespread compliance issues with oil and gas facilities throughout the state, and that the Department’s Enforcement and Compliance Section is challenged by being regularly short-staffed and unable to conduct timely inspections for all New Mexico oil and gas facilities. TR2 526: 25, 527: 1-19, 531: 6-10, 533: 22-23; 557: 22-25, 558: 1-7.

Although NMED's witness, Michael Baca, was concerned that the Chaco Report had not been peer-reviewed, Mr. Baca did not testify that the report's conclusion – that some oil and gas facilities are drilled without an air quality permit regulating the emissions from these operations – was mistaken or that this gap in regulatory oversight does not exist. Moreover, Mr. Baca seemed to be applying a standard to the Chaco Report that he did not similarly apply to the reports relied on by the Department. For example, neither NMED nor Mr. Baca presented testimony or evidence indicating that NMED's Ozone Advance Path Forward had been peer reviewed. In fact, NMED only submitted its Ozone Advance Path Forward to EPA for review and approval in September 2021, and EPA had not concluded its review or approved the plan at the time Mr. Baca and NMED relied on it for purposes of this rulemaking hearing. See NMED Amended Exh. 4 at 1. Mr. Baca also expressed concern that Guardians' proposal "could be taken" to expand NMED's jurisdiction. However, Mr. Baca agreed that NMED has jurisdiction to regulate stationary sources of ozone precursors. TR5 1346: 6-9. Moreover, Mr. Baca did not direct the Board to any statute or regulation that precluded NMED from regulating stationary sources that emit ozone precursors during wellsite construction. See NMED Rebuttal Exh. 22. As discussed above, Guardians' proposal would simply make explicit NMED's existing jurisdiction to regulate ozone precursors emitted from stationary sources during wellsite construction, and that these emissions must be accounted for in the calculation of PTE for the oil and gas facilities subject to the proposed Part 50.

<u>NMOGA supports NMED's position opposing WEG's proposal:</u> See Kuehn/Palmer testimony, NMED Ex. 32:20:3-9. This definition was derived from the Board's air quality operating permit regulations at 20.2.70 NMAC. WEG requested that this definition be revised to include pre-production operations, such as during well pad construction and drilling. Nichols testimony, Tr. 5:1300:4-14. Mr. Blewett outlined some of the practical problems with this approach. Blewett testimony, Tr. 5:1322:1-22; 5:1323:20-5:1324:24. Mr. Baca testified on behalf of NMED that the Department opposes making the definition of potential to emit inconsistent between Part 50 and the permitting programs, Tr. 5:1342:9-15, potentially interferes with another agency's jurisdiction, Tr. 5:1342:16-29, and no real evidence of equipment was introduced, Baca

testimony, Tr 5:1342:20-5:1343:2. NMED also stated that this rulemaking is not intended to be about permitting. Baca testimony, Tr. 5:1345:8-16. [See also NMOGA SOR 59.]

CEP and Oxy propose a new definition related to their proposals below:

SS. "Pre-production operations" means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

MM. "Produced water" means a liquid that is an incidental byproduct from well completion and the production of oil and gas.

NMED: The definition of "Produced water" in Subsection MM of Section 20.2.50.7 was derived from the New Mexico Oil Conservation Commission's regulations at 19.15.2 NMAC. The term is used in Section 126. The Department proposed revisions to this definition based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 20, and NMED Rebuttal Exhibit 1, p. 10. [See also NMOGA SOR 60 and footnote 38 in its redline.]

NN. "Produced water management unit" means a recycling facility or a permanent pit or pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), either of which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

NMED: The definition of "Produced water management unit" in Subsection NN of Section 20.2.50.7 was derived in part from the New Mexico Oil Conservation Commission's regulations at 19.15.2, 19.15.17, and 19.15.34 NMAC. The term is used in Section 126. The Department proposed revisions to this definition based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 20, and NMED Rebuttal Exhibit 1, p. 10.

NMOGA proposes to remove "recycling facility" from this definition. NMED disagrees with this proposal because the Department intended to include recycling facilities within the meaning of this term as used in Part 50. The Board should reject NMOGA's proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 10.

NMOGA proposes to delete "recycling facility":

"Produced water management unit" means ~~a recycling facility or a~~ permanent pit or pond that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), either of which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

NMOGA: The deletion is supported by the testimony of industry stakeholders who have urged the Board to further protect the industry's recycling activities by excluding "recycling facility" from the definition of produced water management units.

The Department has made significant improvements to the produced water management unit standards under 20.2.50.126 NMAC by eliminating arbitrary emissions limits and unproven requirements to apply covers that route vapors to air pollution control devices. With available technology, these standards would have required the oil and gas industry to reduce the size of recycling operations and, in some cases, resort to freshwater. The Department has responded to these concerns by imposing requirements that are achievable with current technology and largely preserve industry's ability to continue recycling activities.

To further protect the industry's important recycling activities, NMOGA urges the Board to exclude recycling facilities from the definition of produced water management units altogether. Several technical witnesses have urged the Department to make this change. See Campsie, CDG Exhibit B, 8:9-15; Campsie, CDG Reb. Ex. B, 4:7-16; Cooper, CDG Reb. Ex. E, 7:11-18. This change is particularly important to clearly exclude recycling facilities that are not at frac ponds or pits, often called Recycle on the Fly (ROTF) units. ROTF are a collection of temporary tanks that move around to accommodate frac schedules. These facilities do not have pits or ponds. Control options for these temporary facilities are very limited, and the tanks hold water that has already been through separation. Any further control would require supplemental fuel and a temporary flare.

The 50,000 bbl threshold contained in the definition of produced water management units will provide relief for some of these operations. NMOGA has provided minor revisions to that definition to clarify the applicability of the 50,000 bbl threshold to recycling facilities. NMOGA believes these changes are consistent with the original definition but provide additional clarity. While this clarification is helpful, NMOGA urges the Board to exclude recycling facilities altogether. A size threshold on recycling facilities does not encourage owners and operators to maximize produced water recycling, a result that is not within New Mexico's public interest. These requested changes will help ensure that the recycling activities critical to New Mexico's future can continue unimpeded. [See related information and arguments in Section 126 below.]

OO. "Qualified Professional Engineer" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

NMED: The definition of "Qualified professional engineer" at Subsection OO of Section 20.2.50.7 was derived in part from NSPS Subpart OOOOa, 40 C.F.R. § 60.5430a. The term is used in Section 20.2.50.111. No party commented on this definition. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 20-21.

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

NMED: The definition of "Reciprocating compressor" in Subsection PP of Section 20.2.50.7 was derived from Colorado Reg. 7, Section I.B.24. The term is used in Section 114. No parties commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 21.

QQ. "Reconstruction" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

NMED: The definition of "Reconstruction" in Subsection QQ of Section 20.2.50.7 was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC. No party commented on this proposal. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, p. 21.

RR. "Recycling facility" means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

NMED: The definition of "Recycling facility" in Subsection RR of Section 20.2.50.7 was derived in part from the New Mexico Oil Conservation Commission's regulations at 19.15.34 NMAC. The term is used in Section 126. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 21, and NMED Rebuttal Exhibit 1, p. 10. NMOGA proposed to remove this definition from Part 50. Ms. Kuehn testified that NMED intended to include recycling facilities within the definition of Produced Water Management Unit, and this definition is necessary to make clear the intended meaning of a recycling facility as used in Part 50. The Board should reject NMOGA's proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 10.

NMOGA proposes to delete **"recycling facility"** entirely: *See* Campsie testimony, CDG Exhibit B, 8:9-15; Campsie testimony, CDG Reb. Ex. B, 4:7-16; Cooper testimony, CDG Reb. Ex. E, 7:11-18. [See also the definition of "produced water management unit" above, and the discussion in Section 126 below.]

SS. "Responsible official" means one of the following:

(1) for a corporation: 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.

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

NMED: The definition of "Responsible official" in Subsection SS of Section 20.2.50.7 was derived from the Board's operating permit regulations at 20.2.70 NMAC. The Department made revisions to its original proposal based on comments from NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 21, and NMED Rebuttal Exhibit 1, p. 10-11. [See also NMOGA SOR 61.]

TT. "Routed pneumatic controller" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.

NMED: The Department proposed to add a definition of "Routed pneumatic controller" in Subsection TT of Section 20.2.50.7 based on comments from NMOGA. The term is used in Section 122. This definition establishes the meaning of the term and the Department's intended use of the term in Part 50. The Board should adopt this proposal for the reasons stated in the NMOGA's testimony and NMED Rebuttal Exhibit 1, pp. 8-9.

UU. "Small business facility" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

NMED: The definition of "Small business facility" in Section 20.2.50.7, and as used in Section 20.2.50.125, is intended to provide regulatory relief to small, independent operators by requiring compliance with only a limited subset of requirements in Part 50. The definition of small business facility in Part 50 distinguishes those companies that are independently owned, have low annual revenues (less than $250,000), and a small number of employees (10 or fewer), from those companies with larger annual revenues ($250,000 or greater) and a greater number of employees (more than 10 employees). NMED Exhibit 102, p. 14.

The proposed definition is based upon three principal criteria that help delineate between small, independent businesses and large, vertically integrated companies. The first criterion is ownership structure, which was used to distinguish companies that are independently owned and operated and are not a subsidiary or division of another company from larger corporations. The differences between small and large companies include the size of the business, number of employees, revenue, legal structures, and financing and tax requirements. Small and large companies may both operate within the same industrial sector, however, the differences in how these companies operate, their ability to access and finance capital, and their overall size affect their operations. *See* NMED Exhibit 102 (Direct Testimony of Susan Day and Elizabeth Bisbey-Kuehn), p. 13.

The second criterion is the total number of staff employed by the company, which is an indication of the company's personnel and staff resource capacity to interpret and implement the requirements of the rule. Larger companies have the financing capacity to employ dedicated environmental, health, and safety specialists; these staff typically monitor the company's compliance with numerous state and federal environmental regulations. Small companies employing fewer numbers of employees typically do not have the staffing or funding capacity to finance dedicated environmental compliance specialists. *Id.*at 14.

The third criterion is annual revenue. The cost of complying with the requirements of Part 50 may disproportionately impact the smallest companies and may result in early abandonment of small business-owned wells, which, in turn, may result in increased uncontrolled air emissions from abandoned wells. Thus, by establishing a definition for small business facility, the Department's proposal tailors the rule to require robust equipment and emission monitoring for smaller, independent operations, while simultaneously balancing those requirements against the unintended negative environmental consequences resulting from early abandonment. *Id.*

To aid in the development of the small business facility provisions, the Department contracted ERG to prepare a report analyzing business structure, revenues, and employment characteristics of the oil and gas companies operating in New Mexico. NMED provided ERG with the names and addresses for well owners/operators and other affected facilities compiled from the NMED Equipment Data and NM Oil Conservation Division data. Using this data, ERG created a master list of 535 well owners/operators and owners/operators of other affected facilities (hereafter collectively referred to as "owners/operators") by combining the two lists and eliminating duplicate entries. *See* NMED Exhibit 102, p. 3; NMED Exhibit. 104 – Owner Address List Final Spreadsheet. ERG used information on industry classification signified by North American Industry Classification System (NAICS) code, as well as the names and addresses of the companies on the master list, to identify and link facilities to global ultimate parent companies in the Dun and Bradstreet (D&B) business database. Information on revenues and employment for global ultimate parent companies was also obtained from D&B. *See* NMED Exhibit 102, p. 3. Ms. Day testified regarding how she conducted this analysis to identify which companies operating in New Mexico were considered to be independent, in the sense that they did not have a separate global ultimate parent company. *See id.* at 3-6. ERG then used oil and gas well production data for New Mexico owner/operators from the Go-Tech website to calculate an estimate of the revenue per well and the average value of the oil and gas production per well for each owner/operator. *See* NMED Exhibit 102, pp. 8-9.

The Department used the data compiled by ERG to establish the thresholds for small business facilities in Part 50. These thresholds were chosen because the data compiled by ERG indicated that those thresholds balanced the costs of compliance with Part 50 against a company's ability to finance the costs of compliance, and would not put the majority of companies at risk of becoming insolvent and therefore cause wells to be abandoned without remediation. *Id.* at 11.

The Department estimated the annual average cost of compliance for a representative well site facility to determine the number of companies that could finance those compliance costs. The representative facility was assumed to have facility-wide emissions greater than 5 TPY VOC, requiring quarterly LDAR monitoring under Section 20.2.50.116; a storage vessel emitting greater than 2 TPY, requiring a control device, and an annual inspection of the storage vessel under Section 20.2.50.123. The annual average cost of compliance for the representative facility was estimated at $37,945 (based on an average cost of $32,400 to control a storage vessel, $4,385 for quarterly LDAR monitoring, and $1,160 for an annual inspection). Because the cost estimates are based on the average cost of compliance for companies operating throughout the sector, the cost estimates are conservative and may overestimate the true cost of compliance for an individual facility. NMED then ranked the companies by GULT revenue from highest to lowest revenue and screened the companies that reported $1,000,000 or less and $250,000 or less to determine how many of those companies had per well site revenue less than the cost of compliance for the representative facility. Based on this review, NMED determined that 96 companies reporting a Global Ultimate (GULT) Parent revenue of $1,000,000 and less had a calculated revenue per well less than $37,945. These companies operate approximately 9,277 wells or 18% of the total wells (9,277/50,866). NMED determined that 54 companies reporting a GULT revenue of $250,000 and less had a calculated revenue per well less than $37,945. These companies operate approximately 4,638 wells or 9% of the total wells (4,638/50,866). *Id.* at 11-12.

The Department then determined the average annual cost of compliance for a facility meeting the small business definition at $4,385 (based on a conservative quarterly LDAR monitoring requirement). According to the report, few companies have a revenue of less than $4,385 per well. *Id.* at 12.

Based on the above, the Department established $250,000 as the revenue threshold to meet the small business definition. This is based on the need to require robust emission reduction requirements for a majority of wells and facilities; to tailor the requirements for companies with low annual revenue; and to reduce the potential early abandonment of wells that will result in increased uncontrolled air emissions and significant public cost to remediate those wells. *Id.*

Based on the ERG report and the proposed definition, a total of 82 companies that operate 4,638 wells would qualify as small business facilities under the thresholds established in the rule. Therefore, under the proposed definition, 15% of the total number of companies (82/535) subject to Part 50 would be considered owners/operators of small business facilities, and 9% of the total number of wells (4,638/50,866) would be considered small business facilities. NMED also estimated the revenue from a well producing 7.5 bbl of oil per day, (7.5 bbl oil/day * 365 days/year * $60.00/bbl of crude oil) as $164,250 per year (or $450 per day). Comparing this estimated revenue with the estimated cost of complying with the small business provisions of Part 50 (estimated at $4,385), it would cost companies approximately 2.6% of total revenue to comply. The estimated cost of compliance for the representative facility (estimated at $37,945) as a percentage of the total estimated revenue is approximately 23% of total revenue. *Id.*

IPANM argues that gross annual revenues are not a measure of a company's profitability. NMED agrees with this statement; however, sales and revenues are commonly used metrics to evaluate the impact that regulatory burdens may place on small, affected entities. In particular, EPA guidance states that "[i]mpacts on small businesses are generally assessed by estimating the direct compliance costs and comparing them to sales or revenues." NMED Rebuttal Exhibit 10 (EPA Guidelines for Preparing Economic Analyses [March 2016]), pp. 9-14. Moreover, the small business definition in proposed Part 50 is two-pronged, containing an employment component in addition to a revenue component. NMED and other state and federal agencies routinely use multi-pronged approaches (e.g., revenues and employment) to set small business definitions.

IPANM argued that the small business facility definition should use a 50-employee threshold based on the definition of "small business" in the New Mexico Small Business Regulatory Relief Act. Similar to exempting low-producing wells, a 50-employee threshold would exempt at least 85% of the companies operating in New Mexico, and approximately 40% of the wells analyzed. *See* Tr. Vol. 3, 945:23 – 946:18. IPANM further argued that using a revenue threshold could result in operators moving in and out of qualifying as a small business from one year to the next due to uncertainties in commodity prices. Ms. Day testified that in rulemakings such as this, it is appropriate to take a snapshot of the industry to profile the affected universe of companies. There will always be economic fluctuations, and both commodity prices and production can be variable. In federal rulemakings similar to Part 50, it is standard practice to pick a snapshot of conditions in the regulated industry when estimating compliance costs and small business impacts. *See* Tr. Vol. 3, 946:19 – 947:6.

NMOGA and IPANM argue that the Board should reject the small business facility provisions proposed by the Department and should instead adopt an approach that would entirely exempt low producing wells from Part 50. The Board should reject this approach because it leaves too many emissions sources unregulated, and therefore runs contrary to the intent of the Board's statutory duties specified in the AQCA. *See* Tr. Vol. 4, 1024:24 – 1027:12. Just because a well is low producing does not mean it is low emitting; based on the number and age of low-producing wells in New Mexico, leaving them out of the rule would amount to leaving tens, if not hundreds, of thousands of tons of ozone precursor emissions uncontrolled and unregulated. *See id.* Further, the Board should find that the Department's proposal already provides relief to low-emitting facilities by establishing PTE thresholds throughout the rule. Facilities that emit below these thresholds are not subject to the requirements for the particular equipment or process to which the rule section at issue applies. *See* Tr. Vol. 3, 945:15-23.

In the course of this rulemaking, no party took issue with the data included in NMED Exhibit 105, as compiled by ERG, and no party submitted proposed changes to the small business facility definition pursuant to the Board's rulemaking procedures at

20.1.1.302.A(5) NMAC (requiring a notice of intent to present technical testimony to "include the text of any recommended modifications to the proposed regulatory change."). *See* Tr. Vol. 3, 885:2-14.

The Board should find that NMED's proposed definition of "Small business facility" together with the provisions of Section 20.2.50.125, sets reasonable minimum requirements such as best management and operational practices, calculation of potential to emit, and repairing leaks, which all companies regardless of size or structure should be able to comply with if they want to operate in this State. *See* Tr. Vol. 3, 1027:7-13.

<u>IPANM proposes changes to the definition of "small business facility":</u>

OO. "Small business ~~facility~~" means, for the purposes of this Part, ~~a source that is independently owned or operated by~~ a company that is a not a subsidiary or a division of another business <u>and</u>, that employs no more than <u>50 </u>~~10~~ employees at any time during the calendar year, ~~and that has a gross annual revenue of less than \$250,000~~. Employees include part-time, temporary, <u>contract, </u>or limited service workers.

<u>IPANM's edits here are related to its arguments for deleting Section 125G; see below.</u>

The Department obtained information on global ultimate parent companies and their associated revenue and employment data. NMED Ex. 102 at 3:13-14 (Day/Bisbey-Kuehn). 154 facilities out of a total of the Department-identified 460 matched New Mexico facilities were identified as global ultimate parent companies. *Id*. at 6:5-12. NMED provided analysis on revenues and employment of well-owners/operators that would be subject to the Part 50. Tr. Vol. 3, 871:20-24 (Bisbey-Kuehn). The U.S. Small Business Administration ("U.S. SBA") defines industry size standards that identify what entities qualify as a small business. NMED Ex. 102 at 6:14-19 (Day/Bisbey-Kuehn). The Department included the size standards for potentially affected owners/operators and other facilities and, using global ultimate parent company information identified for each facility, identified how that global ultimate parent would be classified under U.S. SBA size definition. *Id*. at 7:5-7.

On cross-examination, Ms. Bisbey-Kuehn testified that the definition of a small business under the New Mexico Small Business Regulatory Relief Act, which is distinct from U.S SBA definition of a small business, provides an example of a threshold and may be appropriate in certain publications; however, she argued a need for strong emissions reductions without explaining why the New Mexico definition of a small business would not meet that end. *See* Tr. Vol. 3, 887:6-13 (Bisbey-Kuehn). Out of a total of 406 ultimate parents with revenue and employment data evaluated by NMED, the Department identified 355 global ultimate parent companies that meet the SBA definition of a small business. NMED Ex. 102 at 7:11-18 (Day/Bisbey-Kuehn). "The 355 small global ultimate parent companies are associated with 359 small owner/operators and the 51 not small global ultimate parent companies are associated with 77 not-small owner/operators." Tr. Vol. 3, 875:1-4 (Bisbey-Kuehn).

The Department employed two methods to calculate the value per well. The first method estimated average revenue per well for each owner/operator by dividing the global ultimate parent revenues associated with the owner/operator by the total number of wells reported in the Go-Tech data for that owner/operator. *Id*. at 8:14-16. The Department noted that global ultimate parent revenue per well can be highly variable. NMED Ex. 102 at 9:4-5 (Day/Bisbey-Kuehn). Under the second method, NMED estimated the average value of the oil and gas production per well for each owner/operator. NMED Ex. 102 at 9:11-12 (Day/Bisbey-Kuehn). Using dollars per barrel (BBLS) and dollars per million BTU (MMBTU) for gas, the Department calculated the average value of the production from wells of each type per owner/operator. *Id*. at 9:13-15.

The Department proposed $250,000 as the revenue threshold to meet the small business definition**.** NMED Ex. 102 at 12:14-15 (Day/Bisbey-Kuehn). The Department proposed that an owner or operator of a facility that meets the definition of a small business facility must comply with Sections 111 and 125. NMED Ex. 102 at 10:16-17 (Day/Bisbey-Kuehn). NMED's proposed Section 125 requires that small business facilities operate equipment based on manufacturer specifications, maintain a database of VOC and NOx emissions, are subject to the reporting requirements in Section 112 and the fugitive leak monitoring requirements in Section 116, and must file an annual certification stating that it meets the definition of a small business facility. IPANM Ex. 10 at 25:1-10 (Davis Rebuttal).

NMED explained that its definition of a small business facility was developed to recognize the unique challenges that smaller independent operators may face in determining applicability of complex regulations and financing the initial and ongoing costs of compliance with Part 50. NMED Ex. 102 at 10:20-23 (Day/Bisbey-Kuehn). Accordingly, 15% percent of companies, or 82 out of a total of 535 companies, would be considered small business facilities. *Id*. at 12:19-22. The Department also calculated that the cost of compliance for a small business facility at 2.6% of total revenue. *Id*. at 13:5-7. "The proposed thresholds were chosen because the data compiled by ERG indicated that those thresholds balanced the cost of compliance with Part 50 against the company's ability to finance the costs of compliance and would not put the majority of companies at risk of becoming insolvent and therefore cause wells to be abandoned without remediation." Tr. Vol. 3, 880:22-881:3 (Bisbey-Kuehn). NMED further explained that three criteria were developed to distinguish small and large companies: ownership structure, total number of staff employed, and annual revenue. NMED Ex. 102 at 13:15-14:15 (Day/Bisbey-Kuehn). The Department was unclear as to when the certification for annual revenue becomes applicable. Tr. Vol. 3, 889:18-25 (Bisbey-Kuehn).
NMED testified that 82 companies that operate 4,500 wells would qualify as a small business facility, 15 percent of the total companies subject to Part 50 are considered owners or operators of small business facilities, and 9 percent of the total wells would be considered small business facilities. Tr. Vol. 3, 882:25-883:6 (Bisbey-Kuehn). Part 50 would cost companies approximately 2.6% of total revenue to comply. Tr. Vol. 3, 883:15-17 (Bisbey-Kuehn). The estimated annual average of the cost of compliance was $37,945.00. Tr. Vol. 3, 883:18-21 (Bisbey-Kuehn); NMED Ex. 102 at 11:18-20 (Day/Bisbey-Kuehn). Accordingly, the Department proposed that owners/operators of small business facilities comply with emission reductions, monitoring, and operational requirements under Sections 111 and 125. In addition, small business facilities are to conduct fugitive leak monitoring in Section 116(C) and (D). NMED Ex. 102 at 15:1-23 (Day/Bisbey-Kuehn).

Under the small business facility exception, "the Department is rightsizing the rule to require robust equipment and emission monitoring for smaller, independent operations, while simultaneously balancing those requirements against the unintended negative environmental consequences resulting from early abandonment." NMED Ex. 102 at 14:12-15 (Day/Bisbey-Kuehn). While the Department's $250,000 gross revenue cutoff is based on an operator's average well revenue being less than the cost of compliance, the Department's objective does not provide appropriate relief for small businesses or stripper wells. Tr. Vol. 3, 900:21-23; 902:2-9 (Davis). Low production wells and assets will suffer and incur compliance costs related to implementation of the proposed definition. Tr. Vol. 4, 988:5-12 (Smitherman). First, the Department's analysis did not include costs of compliance with pneumatic controllers and pumps in Section 122. Tr. Vol. 3, 902:10-13 (Davis). Second, while relief is provided to companies that operate a small number of wells, there are many operators that have large numbers of stripper wells and make economic decisions on a well-by-well basis; they are unlikely to absorb the cost of compliance on one well if it cannot support that cost by another well's revenue, thereby resulting in premature abandonment. Tr. Vol. 3, 902:16-24 (Davis); Tr. Vol. 4, 990:20-24 (Smitherman). Smaller businesses have a tougher challenge when they have a larger percentage of low-rate producers in their well inventory. Tr. Vol. 3, 902:16-24 (Davis); Tr. Vol. 4, 1003:22-24 (Smitherman).

As stripper wells operate at lower pressure and lower throughput to the tank, their emissions are lower than higher-pressure type wells. Tr. Vol. 3, 936:7-17 (Davis); Tr. Vol. 4, 1026:11-12 (Bisbey-Kuehn). Stripper wells produce external benefits and costs. Tr. Vol. 4, 1021:10-13 (Smitherman). If external costs of a stripper well are considered when evaluating the regulatory definition of a "small business," it is also appropriate to consider the external benefits provided by those wells. Tr. Vol. 4, 1023:14-20 (Smitherman). Companies examine wells on an individual basis—not on a company profit basis—and thousands of wells would be prematurely plugged and abandoned due to the implementation of the small business definition. Tr. Vol. 3, 903:2-4 (Davis); Tr. Vol. 4, 991:4-9 (Smitherman). A well is plugged and abandoned if future revenue does not justify the investment on that asset. Tr. Vol. 3, 938:22-938:2 (Davis).

A well's production and potential to emit are better measures for which to base relief because operators make economic decisions on a well-by-well basis. Tr. Vol. 3, 903:15-20 (Davis). New Mexico has approximately 31,000 stripper wells, totaling roughly 61% of wells in the state. Tr. Vol. 3, 940:22-941:1 (Davis); Tr. Vol. 4, 1025:7-9 (Bisbey-

Kuehn). The ten-employee cutoff was "a starting point on this definition," but the Department did not engage with potentially affected business when it formulated its small business definition. Tr. Vol. 3, 890:17-22; 891:3-8 (Bisbey-Kuehn). The number was derived from a construction permit fee regulation. Tr. Vol. 3, 894:5-10 (Bisbey-Kuehn). The ten-employee cutoff and gross income threshold are too limiting and will exclude most oil and gas operators in New Mexico. IPANM Ex. 2 at 20:7-8 (Davis Direct). The ten-employee cutoff excludes many of the smaller operators that need relief from some of the provisions in Part 50. Tr. Vol. 3, 901:1-3 (Davis).

IPANM objected to the Department's proposal because few, if any, oil and gas operators in New Mexico meet the definition of a small business facility. IPANM Ex. 2 at 20:7-8 (Davis Direct). NMOGA also contends that no oil and gas operator would qualify under the small business facility definition. NMOGA Ex. A1 at 31:15-16 (Smitherman Direct). 87% of all gas wells will not be able to justify the required compliance costs and operators will be forced to shut them in. ***Id***. at 31:18-21. There are many small businesses in New Mexico that would not qualify for the small business exemption. Many small businesses that operate multiple stripper wells would be affected because the cost of compliance would exceed their gross annual revenue. See Tr. Vol. 3, 911:4-25 (Davis). The gross revenue of an oil and gas producer is tied to the price of oil and gas in the market. It increases or decreases with the price of oil or gas cannot be passed on by the producer nor can an increase in cost. IPANM Ex. 2 at 20:10-12 (Davis Direct). The gross annual revenue is not a measure of the business's profitability. Tr. Vol. 3, 901:10-14 (Davis). NMED agreed. NMED Rebuttal Ex. 1 at 99:1-2. (Kuehn/Palmer Rebuttal). The upfront costs of drilling a well and the infrastructure needed to move the product to a processing facility as well as the ongoing operating expenses are not factored into gross revenues. IPANM Ex. 2 at 20:12-15 (Davis Direct).

In all, the variability with commodity pricing creates a lack of regulatory certainty and is not a good measure of profitability. IPANM Ex. 10 at 4:2-3 (Davis Rebuttal); Tr. Vol. 3, 901:10-14 (Davis). IPANM also identified issues related to NMED's sole consideration of wells that could not support the cost of compliance on average. IPANM Ex. 10 at 4:5-7 (Davis Rebuttal). In IPANM's analysis, there is a positive correlation between the higher percentage of stripper wells and a higher percentage of gross revenue for the cost of compliance. *Id*. at 4: 9-13. A well's production and PTE are better measures to assure necessary relief because they are independent of commodity prices. *Id*. at 4:14-18.

The Department conceded that it is amenable to adjusting or "right-sizing the definition" based on the feedback at the hearing. *See* Tr. Vol. 3, 895:16-21 (Bisbey-Kuehn). While IPANM did not propose alternative language to the small business facility definition and requirements, it initially recommended that 20.2.5.50.7.OO and 20.2.50.125 NMAC not be adopted. IPANM Ex. 2 at 20:19-22 (Davis Direct). IPANM maintained that the low volume and low decline rate gas wells in the San Juan Basin and across New Mexico will be unable to meet the cost of compliance. *Id*. at 21:10-12; *see also* NMOGA Ex. A1 at 31:24-26 (Smitherman Direct).

The Department did not agree to remove Section 125. NMED Rebuttal Ex. 1 at 99:10-11 (Kuehn/Palmer Rebuttal). In response to IPANM's concern that gross annual revenues are not a good measure of profitability, the Department stated that EPA guidance suggests that impacts on small businesses are generally assessed by comparing direct compliance costs to revenues. *Id*. at 99:1-5. However, EPA guidance is not an appropriate impact analysis for oil and gas operations in New Mexico. Tr. Vol. 3, 908:21-24 (Davis). The Department has admitted that gross revenues are not a good measure of profitability. Tr. Vol. 3, 908:22-24; NMED Rebuttal Ex. 1 at 99:1-2. (Kuehn/Palmer Rebuttal).

Lastly, IPANM recommended that the Board consider the definition of a "small business" under the New Mexico Small Business Regulatory Relief Act, which "means a business entity, including its affiliates, that is independently owned and operated and employs fifty or fewer full-time employees." IPANM Ex. 10 at 6:7-12 (Davis Rebuttal); Tr. Vol. 3, 901:3-6 (Davis). The Department has stated that a 50-employee threshold is unacceptable, but it provided no reason for its assertion. *See* Tr. Vol. 3, 946:6-18 (Day). IPANM pointed out, and the Department recognized, that requirements for proper operations and maintenance to reduce emissions, fugitive leak requirements, a database of VOC and NOx emissions, and Section 112 would still be applied. Tr. Vol. 3, 905:23-906:8 (Davis); Tr. Vol. 4, 1030:16-25 (Bisbey-Kuehn). IPANM suggests that the definition of a "small business facility" be amended to reflect that a small business is a company that is a not a subsidiary or a division of another business and that employs less than 50 employees at any time during the calendar year, and that "employees" also include contract workers. IPANM Ex. 10 at 6:7-12 (Davis Rebuttal); Tr. Vol. 3, 901:3-6 (Davis). IPANM supports reducing the requirements applicable to small businesses and notes that the requirements are not a complete exemption of the wells subject to the provision. IPANM Ex. 10 at 26:2-4 (Davis Rebuttal). See IPANM's SOR, pp. 46-54.

<u>NMOGA supports IPANM's contours for small business facilities.</u>

<u>CEP opposes IPANM's proposal:</u> NMED proposed a narrow exemption for "small business facilities" that would exempt oil and gas operations that meet the criteria from some, but not all, requirements of 20.2.50 NMAC. *See* NMED Reb. Ex. 23 at 20.2.50.7.VV, -111.B, C, & -125 NMAC [NMED's Sept. 16, 2021 Proposed Draft].

Under the Department's proposal, a "small business facility" is a source that is independently owned and is not a subsidiary of another company, has 10 or fewer employees, and has a gross annual revenue less than $250,000. *Id.* at 20.2.50.7.VV NMAC. The Department backed up its proposal with detailed analysis from ERG economist Susan Day and NMED Air Quality Bureau Chief Liz Bisbey-Kuehn on the numbers of oil and gas companies that meet each of the three criteria and the Department's rationale for selecting the criteria. In recognition of the potential economic difficulty of compliance for low producing operations, the Department proposes emissions thresholds for many sections of its proposed rule. *See generally* 3 Tr. 870:9-885:18 [Day and Bisbey-Kuehn Test.].

In response to the Department's proposal, NMOGA proposed to delete the exemption entirely claiming that it couldn't identify any oil and gas companies that meet the criteria. While NMOGA witness Mr. Smitherman testified at some length about the supposed economic hardships of the Department's proposed rules on small operators, he acknowledged during cross-examination that:

- NMOGA's proposal is to strike the small business facility exemption,

- NMOGA did not supply any data, analysis, or economic information that would support a general exemption for low-producing wells, but had focused on applicability thresholds for different sections of the rule, and
- NMOGA was not proposing any additional exemptions for small businesses, but was willing to engage in future discussions with the Department and other parties about such an exemption. 4 Tr. 996:14-997:15. NMOGA nonetheless maintained its position throughout its direct and rebuttal NOI filings and at hearing proposing to delete the small business facility exemption. NMOGA did not propose a general exemption of its own. *See* NMOGA App. B at 7; NMOGA Ex. 47 at 7; 4 Tr. 991:18-19, -996:14-997:15.

IPANM took an unorthodox and confusing approach on whether there should be a general exemption for low producing or low emitting operations. In its direct NOI, IPANM witness Ryan Davis opposed the Department's small business facility exemption, recommending that it "not be adopted," and urged an "alternative approach" to broaden the exemption. IPANM Ex. 2 at 20. However, while the EIB's rules require parties to "include the text of any recommended modifications to the proposed regulatory change" in notices of intent to present technical testimony, 20.1.1.302.A(5) NMAC, IPANM failed to include any recommended modifications in its direct or rebuttal NOIs or at hearing. *See* IPANM Ex. 1 [Proposed Modifications]; IPANM Notice of Intent to Present Rebuttal Technical Testimony; 3 Tr. 931:13-22. Instead IPANM acknowledged that "IPANM is not proposing specific language at this time to accomplish this end . . . ." IPANM Ex. 2 at 20.

At hearing, Mr. Davis gave extended but exceedingly general testimony on the claimed hardship to smaller oil and gas operators with complying with the Department's proposed rule, and encouraged the EIB to return to the Department's pre-petition proposal exempting low production and low emitting wells. 3 Tr. 905:7-15; *see also* IPANM Ex. 10 at 28-29. However, Mr. Ryan failed to provide the EIB and the parties with any proposed language in support of this suggestion and failed to provide any analysis whatsoever that would support such a proposal. Mr. Ryan did not even offer the emissions threshold IPANM would support. Mr. Ryan acknowledged during cross-examination that IPANM had not proposed any specific language or any data or economic analysis to support IPANM's very loose proposal. 3 Tr. 930:10-20, -932:3-24.

Mr. Ryan acknowledged he understood the EIB's rules required parties proposing modifications to submit proposed language in their NOIs. 3 Tr. 930:21-931:6. Without proposed language, there is no proposal before the EIB; it is impossible to evaluate any proposal; and the parties' right to cross-examine on any proposal is undermined. *See* NMSA §, 74-2-6.D (under Air Quality Control Act, all interested persons have a reasonable opportunity to examine witnesses testifying at the rulemaking hearing).

Any rule adopted by the EIB must supported by substantial evidence in the whole record. With no analysis, data, or information in support, there is no "substantial evidence" in support of IPANM's suggestion that the EIB return to the Department's pre-petition proposal, and there is no basis for the EIB to consider let alone adopt IPANM's suggestion. The EIB should summarily reject IPANM's suggestion and not expend its limited resources deliberating on IPANM's threadbare recommendation.

Ms. Hull conducted a review of emissions from stripper wells in New Mexico, and determined that "stripper wells are responsible for a disproportionately large portion of emissions, over 22% compared to their low share of production . . . ." 8 Tr. 2612:20-25. This information underscores "the need for frequent instrument-based inspections at these well sites to identify abnormal operating conditions that result in excess venting or leaking." 8 Tr. 2613:1-4. Ms. Hull also conducted a review to determine ownership of stripper wells in New Mexico. This review demonstrates that "companies who operator stripper wells also operate many higher-producing wells." 8 Tr. 2612:12-14. Specifically, companies that own stripper wells are responsible for 99.6% of oil production and 97% of gas production in the state. 8 Tr. 2611:25-2612:3.

Mr. Alexander, a former oil and gas executive, pointed out that an asset portfolio consisting solely of stripper wells can still produce significant amounts of oil and gas and generate considerable income. 10 Tr. 3237:12-25. He further noted that companies that operate multiple stripper wells located close together will often view the combined assets as one entity when evaluating potential compliance costs and mitigation efforts. 10 Tr. 3238:9-14.

Ms. Hull's analysis directly rebuts Mr. Davis' and Mr. Smitherman's testimony on the alleged economic hardship of the Department's proposed rules on small operators because Ms. Hull's analysis demonstrates that companies that operate low-producing stripper wells also operate high producing assets. [See also CEP SOR 358-373.]

VV. "Stabilized" means, when used to refer to stored condensate, that the condensate has reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses."

NMED: The Department is proposing adding a definition of "Stabilized" at Subsection VV of Section 20.2.50.7 based on its agreement at the hearing with the definition as proposed by NMOGA. The term is used in Section 20.2.50.111. Tr. Vol. 4, 1230:1-5. The Board should adopt this proposal for the reasons stated in NMOGA's testimony.

WW. "Standalone tank battery" means a tank battery that is not designated as associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station.

NMED: The Department is proposing a definition of "Standalone tank battery" at Subsection WW of Section 20.2.50.7 based on testimony from NMOGA. The term is used in Section 20.2.50.111. At the hearing, the Department agreed to include a definition of "tank battery" and worked with NMOGA following the hearing to come up with the proper language. As part of that definition, another definition of "standalone tank battery" was required to delineate between those tank batteries that are associated with other defined facilities and those that are not. This definition provides clarity regarding the applicability of the requirements in Part 50 to storage tanks not associated with another facility regulated under Part 50. The Board should adopt this proposal for the reasons stated at Tr. Vol 4, 1110:2-7; 1113:9 – 1120:6. [See also NMOGA SOR 62.]

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

NMED: The definition of "Startup" in Subsection XX of Section 20.2.50.7 was derived from the Board's excess emissions regulations at 20.2.7 NMAC. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 22.

YY. "Stationary source" or "source" means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

NMED: The definition of "Stationary source" or "source" in Subsection YY of Section 20.2.50.7 was derived from the Board's air quality construction permit regulations at 20.2.72 NMAC. No party commented on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 22.

IPANM proposed moving the last sentence into a separate definition; see above for new definition **"portable stationary source."**

ZZ. "Storage vessel" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck or railcar; a process vessel such as a surge control vessel, bottom receiver, or knockout vessel; a pressure vessel designed to operate in excess of 204.9 kilopascals (29.72 psi) without emissions to the atmosphere; or a floating roof tank complying with 40 CFR Part 60, Subpart Kb.

NMED: The definition of "Storage vessel" in Subsection ZZ of Section 20.2.50.7 was derived in part from Colorado Reg. 7, Section I.B.27, and NSPS Subpart OOOOa, 40 C.F.R. § 60.5365a. The term is used in Section 123. The Department made revisions to its original proposal based on comments from NMOGA. The Department is proposing further revisions to address storage vessels with a floating roof tank complying with federal NSPS regulations based on testimony from NMOGA at the hearing. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 22-23; NMED Rebuttal Exhibit 1, p. 11; and Tr. Vol 9, 2881:2 – 2883:5, 2885:4 – 2887:18. [See also NMOGA SOR 65.]

AAA. "Tank battery" means a storage vessel or group of storage vessels that receive or store crude oil, condensate, or produced water from a well or wells for storage. The owner or operator shall designate whether a tank battery is a standalone tank battery or is associated with a well site, gathering and boosting station, natural gas processing plant, or transmission compressor station. The owner or operator shall maintain records of this designation and make them available to the department upon request. A tank battery associated with a well site, gathering or boosting station, natural gas processing plant, or transmission compressor station is subject to the requirements in this Part for those facilities, as applicable. Tank battery does not include storage vessels at saltwater disposal facilities or produced water management units.

<u>NMED:</u> The Department is proposing a definition of "Tank battery" at Subsection ZZ of Section 20.2.50.7 based on testimony from NMOGA. The term is used in Section 20.2.50.111. At the hearing, the Department agreed to include a definition of "tank battery" and worked with NMOGA following the hearing to come up with the proper language. This definition provides clarity regarding the applicability of the requirements in Part 50 to storage tanks associated with different types of facilities, and further clarifies that the term does not apply to storage vessels at saltwater disposal facilities or produced water management units. The Board should adopt this proposal for the reasons stated at Tr. Vol 4, 1110:2-7; 1113:9 – 1120:6. [See also NMOGA SOR 63-64.]

<u>CDG supports this definition.</u>

BBB. "Temporarily abandoned well site" means an inactive well site where the well's completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

<u>NMED:</u> The Department proposes this definition as part of its support for the joint proposal of the eNGOs and Oxy USA at Paragraph (9) of Subsection C of 20.2.50.116. The Department refers the Board to the testimony and findings from those parties for supporting information on this definition. [See discussion in Section 116 below.]

CCC. "Transmission compressor station" means a facility, including all equipment and compressors, that moves pipeline quality natural gas at increased pressure from a well site or natural gas processing plant through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, underground storage, or to other industrial end users. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

__NMED:__ Subsection CCC of Section 20.2.50.7 defines “Transmission compressor station” as used in Part 50, specifically Section 20.2.50.111. This definition clarifies the segment of the oil and gas industry included in this term, as used in the definition of “Gathering and boosting station” at Subsection P of Section 20.2.50.7. The Board should adopt this proposal for the reasons stated at NMED Exhibit 32, pp. 8, 22.

__KINDER MORGAN:__ Kinder Morgan supports the Department’s revised definition of “gathering and boosting station,” deleted definition of “natural gas compressor station,” and added (and subsequently revised) definition of “transmission compressor station.” Operations in the transmission segment differ significantly from other segments of industry. This separate definition is necessary to apply each rule section, as appropriate, to the unique transmission segment operations.

DDD. “Vessel measurement system” means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

__NMED:__ The definition of “Vessel measurement system” is part of the automatic tank gauging proposal put forward by the eNGOs and Oxy USA in the Joint Proposal. The term is used in Section 123. In support of this proposal, the Department refers the Board to the testimony presented by CAA on this topic. [See discussion in Section 123 below.]

__The CEP and Oxy and EDF propose a new definition related to their proposals below:__

LLL. “Wellhead only facility” means a well site that does not contain any production or processing equipment other than artificial lift natural gas driven pneumatic controllers and emergency shutdown device natural gas driven pneumatic controllers.

EEE. “Well workover” means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

__NMED:__ The definition of “Well workover” in Subsection DDD of Section 20.2.50.7 was derived from the MAP Technical Report at NMED Exhibit 10. The term is used in

Section 124. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 150-52.

FFF. "Well site" means the equipment under the operator's control directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant or gathering and boosting station, if any. A well site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. A well site does not include an injection well site.
[20.2.50.7 NMAC - N, XX/XX/2021]

NMED: The definition of "Well site" at Subsection FFF of Section 20.2.50.7 was derived from Colorado Reg. 7, Section I.B.30, and NSPS Subpart OOOOa, 40 CFR § 60.5430a. The term is used in Section 20.2.50.111. The Department revised its original definition to replace the term "Wellhead" with "Well" based on comments submitted by NMOGA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 23, and NMED Rebuttal Exhibit 1, pp. 7, 20-21.

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.
[20.2.50.8 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.8 ensures that if any provision of Part 50 is found by a court to be invalid, such finding will not affect the validity and enforceability of the other provisions of the rule. The Board should adopt this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose. [20.2.50.9 NMAC - N, XX/XX/2021]

NMED: Section 20.2.50.9 directs that Part 50 must be liberally construed to carry out its purpose. The Board should adopt this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.
[20.2.50.10 NMAC - N, XX/XX/2021]

<u>NMED:</u> Section 20.2.50.10 provides that repeal or supersession of prior versions of Part 50 will not affect any administrative or judicial action initiated under those prior versions. The Board should adopt this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2021]

<u>NMED:</u> Section 20.2.50.11 makes clear that compliance with Part 50 does not relieve a person from the responsibility to comply with other laws or regulations. The Board should adopt this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

<u>NMED:</u> Section 20.2.50.12 identifies where documents incorporated and cited in Part 50 may be reviewed. No party commented on this proposal. The Board adopts this proposal for the reasons stated in Tr. Vol. 2, 623:19-21.

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:
A. This Part applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquids or produced water in the areas specified in 20.2.50.2 NMAC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

<u>NMED:</u> Subsection A of Section 20.2.50.111 outlines the specific sources of air pollutants that are covered under Part 50. The rule applies to certain crude oil and natural gas production and processing equipment associated with operations that extract, collect,

separate, dehydrate, store, process, transport, transmit, handle hydrocarbon liquids or produced water in areas of the state specified in Section 20.2.50.2 and located at well sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations up to the point of the local distribution company custody transfer station. Part 50 applies to state, federal, and privately owned land, but does not apply to tribal lands or Bernalillo County. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 23.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer or an inhouse engineer with expertise in the operation of oil and gas equipment, vapor control systems, and pressurized liquid samples. The emission standards and requirements of this Part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this Part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request. This certified calculation shall be completed before startup for new sources, and within two years of the effective date of this Part for existing sources.

NMED: Subsection B of Section 20.2.50.111 specifies how to determine whether a source is subject to Part 50. Owners and operators must calculate the PTE of each potentially affected source to determine if it is subject to requirements under the rule. The PTE calculation must be certified by a qualified profession engineer or inhouse engineer with expertise in the specified areas. This certification is critical to ensuring the potential air emissions from equipment and processes are properly calculated and representative of the source, and present a true and accurate representation of the source's potential emissions. Without this certification, emission calculations may be performed based on process, emission, or operational inputs that are not accurate or representative, which then underestimate the true potential emissions and result in a determination that equipment is not subject to this part. The PTE calculation is the foundation of determining applicability of Part 50 and the certification of the PTE calculation ensures the integrity of how that fundamental calculation is performed. Accordingly, it is imperative that PTE calculations be certified by engineers with relevant background and experience. NMED did agree with NMOGA's proposal to allow in-house engineers to do PTE certifications. The New Mexico licensing statute does not require an engineer employed with a company to be licensed. *See* Tr. Vol. 4, 1169:23 – 1170:4.

NMED added language in the second sentence to clarify that the emission standards and requirements of Part 50 may not be used to reduce the emission rate of a source in order to determine applicability of the rule to that source. *See* Tr. Vol. 4, 1158:7-13. NMED is also proposing a compliance date for when PTE certifications must be completed, in recognition of the large number of sources that will need to undergo evaluation and certification under this provision. The Board should adopt this proposal for these reasons, as stated above and in NMED Exhibit 32, p. 24.

Several industry parties proposed that consultants who are not engineers should also be able to certify PTE calculations. The Department disagrees with these proposals. As discussed previously, the entire purpose of this subsection is to require certification by an engineer with relevant expertise. Ms. Kuehn explained that in her experience, PTE calculations frequently miscalculate or misrepresent a source's PTE. This often results in compliance issues for the company, which requires enforcement action and consequent revisions to applications and new permits with corrected emissions values. Because of this experience, the Department very much intended for the PTE calculation to undergo the review of an engineer with that specific type of experience, and for that person to affirmatively sign off that the emissions determination is accurate and representative of the source's true potential to emit. Tr. Vol. 4, 1166:19 – 1168:1. For the reasons outlined in the Department's testimony, the Board should reject the proposals to allow non-engineer consultants certify PTE calculations for applicability of Part 50.

[Oxy's earlier proposal to use actual emissions rather than PTE for determining applicability under Section 20.2.50.111 is not in their final proposal.]

<u>NMOGA proposes to insert **"air consultant,"** after the word "qualified" and supports the final sentence in Section B providing 2 years for the calculation:</u> The applicability of requirements under 20.2.50 NMAC turns largely on a source's potential to emit, which is "the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design." 20.2.50.7.MM NMAC. NMED's proposal prohibits air quality consultants who are not engineers from conducting this potential to emit analysis. The record does not support NMED's insistence that only an engineer is qualified to calculate

potential to emit. The Board should ensure the integrity of potential to emit calculations by simply requiring that the engineer, consultant or inhouse staff be appropriately qualified based on training and experience. NMED's testimony is that they wanted a certain level of assurance that the evaluation was accurate. See Bisbey-Kuehn testimony, Tr. 4:1157:17-4:1158:6; 4:1161:4-22. NMED admitted, however, that an engineer is not required for even complex permitting potential to emit calculations. Bisbey-Kuehn testimony, Tr. 4:1161:23-4:1162:4. Industry representatives testified that many professional engineers have no relevant expertise and that air quality consultants or compliance specialists, versed in how the air program determines potential to emit, were likely more qualified. See Smitherman testimony, Tr. 4:1172:5-21; Marquez testimony, 5:1474:20-5:1475:25; Davis Testimony, Tr. 4:1183:4-19; 4:1184:4-20. Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. What is important is that the engineer, consultant or inhouse staff be appropriately trained and qualified. The proposed redline revisions make the focus on the qualification of the person performing the work and will avoid hamstringing the program.

This requirement would also be more stringent than federal law. PTE calculations for federal standards and permits are routinely done by non-engineering air quality consultants. As such, the Board cannot adopt these standards unless it finds they are more protective. It cannot make such a finding. The record demonstrates that NMED's engineering requirement creates unnecessary, hamstringing barriers around the air quality professionals who are often most qualified to conduct this work.

As to the 2 years allowed to complete the calculation, the testimony is clear that there are over a hundred thousand of pieces of equipment subject to proposed Part 50. Mr. Powell testified that there are 53,338 active oil and gas wells. Tr. 3:741:7-16. The LDAR testimony made it clear that each well has multiple pieces of equipment. Oxy noted that for its 645 facility and 2,745 wells, this requirement could add nearly 6,780 engineering hours, at a cost of over $800,000. Holderman testimony, Tr. 4:1195:16-4:1196:7. The EIB should provide at least two years to complete the certified calculations. [See also NMOGA SOR 66-67.]

IPANM: NMED originally proposed a requirement in Section 111 that a calculation of the potential to emit for sources subject to Part 50 be certified by a qualified professional engineer. NMED explained that requiring a professional engineer to certify calculations "is critical to ensuring the potential air emissions from equipment and processes are properly calculated and representative of the source, and present a true and accurate representation of the source's potential emissions." NMED Ex. 32 at 24 (Bisbey-Kuehn/Palmer Direct). NMED expressed reservation that without a professional engineer to certify the calculations, the potential emissions could be calculated incorrectly, which has the consequence of leaving equipment out of Part 50. Id.

IPANM opposed this requirement noting that certification by a professional engineer is unnecessary and burdensome on small producers. IPANM Ex. 2 at 6 (Davis Direct); IPANM Ex. 10 at 8 (Davis Rebuttal). The New Mexico Board of Licensure for Professional Engineers and Professional Surveyors exempts in-house engineers who perform "only the engineering services involved in the operation of the business entity's business" from the requirements of the Engineering and Surveying Practice Act. IPANM Ex. 2 at 6 (Davis Direct). NMOGA also opposed this requirement, noting that not all registered professional engineers would have the necessary background or specialized oilfield knowledge to be able to complete these calculations. NMOGA Appendix A1 at 14 (Smitherman Direct). Mr. Smitherman highlighted that a properly trained and experienced company employee may have a significantly better working knowledge of a piece of equipment than a professional engineer. Id. Finally, Mr. Smitherman testified that the need to use a registered professional engineer to certify calculations would create a human resource bottleneck that will result in additional costs of implementation of the rule without a discernable benefit. Id. at 14-15.

Oxy highlighted similar concerns as NMOGA and IPANM and additionally described how using an in-house engineer would still meet the goals of Section 111, but would lighten the financial burden that would be required if hiring a professional engineer was necessary. Oxy Ex. 2 at 20 (Holderman Direct). NMED recognized the burden this requirement could create and amended its proposal to also allow for an "inhouse engineer with expertise in the operation of oil and gas equipment, vapor control systems, and pressurized liquid samples" to certify the required potential to emit calculations. NMED Rebuttal Ex. 2 at 5 (Proposed 20.2.50 NMAC – Sept. 7, 2021). NMED testified that it was concerned about the necessary qualifications required for doing defensible PTE calculations. Tr. Vol. 4, 1158:1-6 (Bisbey-Kuehn). NMED believed its revisions to include an option to use an in-house engineer satisfies the concerns raised by the parties. Tr. Vol. 4, 1157:24-1158:6 (Bisbey-Kuehn). NMED clarified that it must be a professional engineer or an in-house engineer who would have to certify the calculations and that this would preclude a consultant from being able to certify these calculations. Tr. Vol. 4, 1161:2-1162:4 (Bisbey-Kuehn).

NMOGA testified that it agreed with the changes to allow an alternative to a registered, professional engineer to need to certify the calculations. Tr. Vol. 4, 1172:5-21 (Smitherman). IPANM testified that while it largely agreed with NMED's change to include in-house engineers, it still had concerns that small companies will need to use an outside consultant because they do not have an in-house engineer. Tr. Vol. 4, 1183:4-11 (R. Davis). IPANM further testified that the regulatory specialist employed by Mr. Davis's company was not a professional engineer, but had expertise that NMED was looking for in the certifications of the calculations. Tr. Vol. 4, 1184:12-20 (R. Davis). IPANM believed there needs to be additional flexibility in the rule to allow for a regulatory specialist to handle the PTE certification. Tr. Vol. 4, 1184:15-20 (R. Davis). Oxy testified that it supports NMED's changes to the rule to allow for an in-house engineer to certify PTE calculations. Tr. Vol. 4, 1196:19-1197:5 (Holderman). The Board should find that allowing an in-house engineer or similarly qualified environmental professional to certify potential to emit calculations is appropriate and is consistent with NMED's goal to have PTE's properly calculated.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

<u>NMED:</u> Subsection C of Section 20.2.50.111 specifies that owners and operators of small business facilities as defined in 20.2.50.7.UU are subject to the requirements of Section 20.2.50.125. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 24; NMED Ex. 102; and NMED Rebuttal Exhibit 1, pp. 11, 98-99.

D. Oil transmission pipelines, oil refineries, natural gas transmission pipelines (except transmission compressor stations), and saltwater disposal facilities are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2021]

NMED: Subsection D of Section 20.2.50.111 lists several types of oil and gas-related facilities that are not subject to Part 50. The Department has proposed clarifying revisions as suggested by NMOGA to effectuate the Department's intent that the purpose of the rule is not to regulate oil transmission pipelines. *See* Tr. Vol. 4, 1156:5-16; 1157:5-9. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 7-9, 23-24, and Tr. Vol. 4, 1156:5-16, 1157:5-9.

CDG supports the exclusion of salt water disposal facilities: The emissions profile at disposal wells is entirely different than the producing operations that create the incoming water. The disposal wells do not have the same emission sources as production facilities and do not receive produced natural gas or oil. The water received from the producing wells is low volatility, post-flash, and has gone through separation, processing, and treatment at the producing sites. Therefore, the water is at atmospheric conditions. Once the produced water has been separated from hydrocarbons at the producing operations, it is then transported by truck or pipeline to Salt Water Disposal (SWD) facilities for further hydrocarbon removal. Typically, incoming water is comprised of about 0.5 percent hydrocarbons. SWDs remove remaining hydrocarbons and then inject the water into an injection well regulated by EPA's underground injection control program, which is administered by EMNRD's Oil Conservation Division. The disposal well itself is not an emission point because it is injecting water that has been cleaned and filtered and therefore, contains only trace amounts of hydrocarbons.

The oil that is separated from the water at SWD facilities is also different than the oil produced from and E&P sites. It is less volatile and is considered "dead" oil because it has limited flashing and emission potential. Any recovered oil is transported offsite typically to refineries ultimately for beneficial use. Therefore, it is appropriate to exclude SWD from the Proposed Rule. CDG NOI Direct Testimony: Lori Marquez, pgs. 5-6; Il Kim, pgs. 3-4; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, or good engineering and maintenance practices. When used in this Part, the term manufacturer specifications means either the original equipment manufacturer (or successor) emissions-related design specifications, maintenance practices and schedules, or an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience. The owner or operator shall keep manufacturer specifications on file when available, as well as any alternative specifications that are being followed, and make them available upon request by the department. The terms of 20.2.50.112.A(1) apply any time reference to manufacturer specifications occurs in this Part.

<u>NMED:</u> Subsection A of Section 20.2.50.112 outlines general provisions that establish a universal set of requirements applicable to all owners and operators of sources of emissions subject to emissions standards and other requirements of Part 50. Paragraph (1) of Subsection A of Section 20.2.50.112 establishes work practice standards requiring equipment to be operated and maintained consistent with manufacturer specifications and explains what is meant by the term “manufacturer specifications” as used in Part 50. Based on a proposal by NMOGA, proposed revisions that allow owners or operators to use either manufacturer specifications or an alternative set of specifications and maintenance practices and schedules developed by qualified personnel based on engineering principles and field experience. Manufacturer specifications or alternative specifications must be kept on file and provided to the department upon request. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 25 and NMED Rebuttal Exhibit 1, p. 21.

(2) Sources, including associated air pollution control equipment and monitoring equipment, subject to emission standards or requirements under this Part shall at all times, including periods of startup, shutdown, and malfunction, be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions of VOC and NOx. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that the owner or operator reduce emissions from the affected source to the greatest extent consistent with safety and

good air pollution control practices. The general duty to minimize emissions does not require the owner or operator to make any further efforts to reduce emissions beyond levels required by the applicable standard under this Part. The terms of 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.

NMED: Paragraph (2) of Subsection A of Section 20.2.50.112 establishes a requirement that equipment be operated a manner that minimizes emissions of air contaminants, including NOx and VOC. This is a standard operational requirement intended to ensure that equipment is used for its intended purpose only; that equipment is maintained in good working order such that it operates within its normal operating parameters, loads, and process and throughput rates; and that owners and operators proactively address any operational issues to avoid excess emissions due to equipment failures, malfunctions, or lack of proper maintenance and operation. This provision includes revisions proposed by NMOGA that clarify the sources covered; specify that the requirement applies at all times including during periods of startup, shutdown, and malfunctions; and clarify the Department's intent that the general duty to minimize emissions does not require the owner or operator to make further efforts to reduce emissions if emission levels required by applicable standards have been achieved. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 25; and NMED Rebuttal Exhibit 1, p 21.

IPANM withdrew its proposal to strike entirely the general requirement for owners and operators to operate sources in a manner that minimizes the emissions of ozone precursors. This requirement establishes a reasonable obligation on the part of owners and operators. *See* NMED Rebuttal Exhibit 1, pp. 21-22.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring equipment monitoring, testing, or inspection shall develop and implement a data system(s) capable of storing information for each source in a manner consistent with this section. The owner or operator shall maintain information regarding each source requiring equipment monitoring, testing, or inspection in a data system(s), including the following information in addition to the required information specified in an applicable section of this Part:

(a) unique identification number;

(b) location (latitude and longitude) of the source;

(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

(d) for each source, the controlled VOC (and NO_x, if applicable) emissions in lbs./hr. and tpy;

(e) make, model, and serial number; and

(f) a link to the manufacturer maintenance schedule or repair recommendations, or company-specific operational and maintenance practices.

(4) The data system(s) shall be maintained by the owner or operator of the facility.

(5) The owner or operator shall manage the source's record of data in the data system(s). The owner or operator shall generate a Compliance Database Report (CDR) from the information in the data system. The CDR is an electronic report maintained by the owner or operator and that can be submitted to the department upon request.

(6) The CDR is a report distinct from the owner or operator's data system(s). The department does not require access to the owner or operator's data system(s), only the CDR.

(7) The owner or operator's authorized representative must be able to access and input data in the data system(s) record for that source. That access is not required to be at any time from any location.

(8) The owner or operator shall contemporaneously track each monitoring event, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be uploaded into the data system as soon as practicable, but no later than three business days of each compliance event, and when the final reports are received;

(b) certain sections of this Part require a date and time stamp, including a GPS display of the location, for certain monitoring events. No later than one year from the effective date of this Part, the department shall finalize a list of approved technologies to comply with date and time stamp requirements, and shall post the approved list on its website. Owners and operators shall comply with this requirement using an approved technology no later than two years from the effective date of this Part. Prior to such time, owners and operators may comply with this requirement by making a written or electronic record of the date and time of any affected monitoring event; and

(c) data required by this Part shall be maintained in the data system(s) for at least five years.

(9) The department for good cause may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. Such requests may be made no more than once per year. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department. The owner or operator may request a hearing on whether good cause was demonstrated or whether the recommendations approved by the department must be implemented.

<u>NMED:</u> Paragraphs (3) through (8) of Subsection A of Section 20.2.50.112 establish requirements for owners and operators to develop and maintain a data system capable of storing monitoring, testing, and inspection information as required under Part 50. These provisions outline what equipment data and compliance monitoring information are

required to be maintained for each source subject to Part 50, and provide that the owner or operator must be able to generate a Compliance Data Report (CDR) from the data stored in the data system(s) and submit the report to the Department upon request. Owners and operators have two years from the effective date to develop and implement the required data system. NMED proposed revisions clarifying that the CDR is a report that is distinct from the owner or operator's data system(s) and that the Department does not require access to the data system(s). An owner or operator's authorized representative must be able to access the data system(s) and input data. Monitoring events must be contemporaneously tracked and the data uploaded to the data system(s) in a timely manner. Where specific sections of the rule require a date and time stamp for a monitoring event, Paragraph (8) provides that the Department will finalize a list of approved technologies to comply with the date and time stamp requirements and will post that information on its website within one year of the effective date of Part 50. Owners and operators must comply with the requirement to use an approved technology for date and time stamping within two years of the effective date, and in the meantime can comply with the requirement by making a written or electronic record of the date and time of a required monitoring event. Data in the data system(s) must be maintained for a period of at least five years. NMED Exhibit 32, pp. 25-26; NMED Rebuttal Exhibit 1, pp. 22-24; Tr. Vol. 1358:5 – 1359:14.

These provisions were substantially revised from the Department's initial proposal, which would have required that all sources be equipped with a scannable tag (an "Equipment Monitoring Tag" or "EMT") that would be integrated with a database and used to track equipment information and compliance monitoring events and data. Based on testimony from the industry parties regarding the costs and burdens entailed by the EMT system and integrated database, the Department removed the tagging and scanning requirements and changed the database requirement to a requirement to maintain a data system or systems for tracking and maintaining compliance data and other information for affected sources. Tr. Vol. 5, 1582:14 – 1583:18.

IPANM proposes to remove these paragraphs in their entirety. The Board should reject this proposal. As stated in NMED's rebuttal testimony, these provisions establish reasonable requirements for all owners and operators subject to Part 50 to operate and maintain a data system where monitoring data, emissions data, and other general information for each affected source can be complied and stored in a manner that allows a report containing the relevant information to be generated and provided to the Department upon request. These requirements are critical to NMED's ability to ensure that affected sources are complying with Part 50 so that the reductions in ozone levels predicted by the modeling can actually be achieved. NMED Rebuttal Ex. 1, pp. 22-23.

With regard the requirement that monitoring events be contemporaneously recorded, the Department has proposed revisions clarifying that only the recording of the event must be contemporaneous; the uploading to the data system does not need to be contemporaneous, but must be done as soon as practicable. The Board should reject the proposals to remove the requirements that each monitoring event be contemporaneously recorded and uploaded to the data system as soon as practicable. This tracking and uploading provides assurance to NMED and the public that compliance monitoring is actually occurring in accordance with the requirements of Part 50. NMED has revised this provision to require an owner or operator to include a date and time stamp, including GPS location information, for monitoring events for certain sources. In order to clarify the date and time stamp and GPS requirement, NMED will work with stakeholders to identify the technology options that can be used satisfy these requirements. There are multiple options for meeting this requirement, and NMED will not prescribe any specific method for doing so. There are many applications for date and time stamping with GPS, and these applications add the required information to photos and other documents. There are also multiple mobile employee time tracking applications with GPS tracking capability. The new proposed language in this Section requires NMED to finalize a list of approved technologies and post that information on its website no later than one year from the effective date of Part 50. Based on comments from NMOGA and IPANM, NMED has proposed a revised timeline allowing owners and operators subject to these requirements two years from the effective date of Part 50 to begin using one of the Department-approved methods to comply with this requirement. Tr. Vol. 5, 1582:14-17. Prior to such time, owners and operators may comply with this requirement with a written or electronic record of the date and time of any affected monitoring event. The Board should adopt NMED's proposal for the reasons stated in NMED Exhibit 32, pp. 25-26; NMED Rebuttal Exhibit 1, p. 22-24; Tr. Vol. 1358:5 – 1359:14.

Paragraph (9) of Subsection A of Section 20.2.50.112 establishes a requirement for owners and operators to retain a third party at their own expense to verify any information collected, reported, or recorded pursuant to Part 50, if requested by the Department. The third party must conduct an assessment and make recommendations to correct or improve the data collected. The owner or operator is required to share the third-party assessment and recommendations with the Department and implement them in a manner approved by the Department. As discussed in the Department's testimony, the third-party compliance verification requirement provides a critical auditing option if the Department suspects or finds that an owner or operator is failing to meet requirements under Part 50. Such verification will benefit the Department's compliance program in significant ways. Having a compliance assessment conducted and a report prepared by an outside third-party results in a considerable time and resource savings for the Department, which already operates under limited staffing and financial resources. The Department can review the compliance assessment report highlighting any issues and recommendations, and approve the manner in which the recommendations are implemented. This approach will improve and increase the public's confidence in the company's compliance with Part 50. In sum, the ability of the Department to require a third-party compliance audit strengthens the overall rule; saves limited staffing resources; improves the public's confidence in compliance with the rule; will result in overall better compliance; and provides owners and operators with targeted recommendations on how to improve any compliance issues identified in the report. NMED Exhibit 32, pp. 26-27.

The Department incorporated revisions proposed by industry parties requiring that requests for third party audits be based on good cause, to limit such requests to once per year, and to allow an owner or operator to request a hearing to review the Department's asserted cause for requesting a third-party audit and/or the compliance recommendations made by the third party. These revisions provide a remedy if owners and operators do not believe there is good cause for a requested audit, or disagree with the recommendations resulting from that audit. NMED Rebuttal Exhibit 1, p. 24. The Board should adopt the Department's proposal for the reasons stated above.

IPANM proposes to delete Section (9) in its entirety. The Board should reject this proposal because this requirement provides a reasonable, resource-conserving option for the Department to obtain third-party verification of compliance with this Part and recommendations on how to improve such compliance. NMED Rebuttal Exhibit 1, p. 24.

<u>GCA:</u> The GCA supports the NMED's removal of the EMT requirements from the proposed data system requirements in 20.2.50.112(A)(3). The tagging requirement included in the July 2021 draft of the proposed rule would have been unnecessarily complex and burdensome, and the compliance demonstration, recordkeeping, database, and database reporting requirements in 20.2.50 will provide ample compliance demonstration information to the Department without the additional cost and burdens associated with the EMT requirement. GCA Exhibit 15 (Copeland Direct) at 8-22. [GCA does not propose other edits in this section. For more details about the testimony of Mr. Copeland, see GCA Closing Argument pp. 16-18 and proposed SOR 6-9.]

<u>CDG:</u> The CDG supports 112A and C, and proposes to insert **"as required by 20.2.50.112(C)(3) and 112(D)"** at the end of paragraph A(5). CDG also proposes to change **"data system"** to **"database system"** throughout; see Revision: "Data system" changed to "database system" throughout Section 20.2.50.112. Hearing Transcript: Proposal by CDG, Lori Marquez, Volume 5, pg. 1471, lines 3-12. Acceptance by NMED: Bisbey-Kuehn, Volume 5, pg. 1582, line 18 through pg. 1583, line 18.

<u>CDG:</u> The CDG, similar to most operators, have internal compliance programs that regularly evaluate compliance of their operations. Subsection A(3) of 20.2.50.112 requires operators to develop and implement a data system capable of storing information for each source in a manner consistent with this section. Utilizing the term "data system" rather than "database system" gives owners and operators the flexibility to choose their own data system and to work from their existing software or select some other appropriate software. For small operators, for example, spreadsheets may be acceptable if they track all data points and store and retrieve all information necessary to comply with Section 20.2.50.112. Owners and operators can then readily generate the CDR

required by Subsection C of 20.2.50.112. from the information in their data system. In addition, allowing owners and operators to generate their CDRs on July 1st of each year instead of March 1 alleviates the burden on companies during a time when a number of other air quality reports are due to state and federal agencies. [CDG NOI Direct Testimony: Lori Marquez, pgs. 2-4; Hearing Transcript Volume. 5, 1471:3-12; 1582:18 – 1583:18; 1488:17 – 1493:15; 1583: -1585:20.]

<u>NMOGA proposed several changes in paragraphs (3) through (9), most of which were already made by NMED above (and so are not shown here); two remain:</u> First, at the end of paragraph (5), insert the words **"as required by Paragraph 3 of Subsection C and Subsection D of 20.2.50.112 NMAC."** The data system(s) can be one or more systems so long as they are capable of producing the compliance data report (CDR) within the required time frame. Bisbey-Kuehn testimony, Tr. 5:1368:8-19. NMOGA also appreciates the new terminology as it eliminates possible disputes over whether a simple Excel spreadsheet is an adequate "database" under prior language. Marquez testimony, Tr. 5:1471:3-12. NMOGA is supportive of the CDG's suggested language addition at the end of this provision.

Second, in paragraph (8), delete **"contemporaneously"** before the word "track." "Contemporaneously" is ambiguous and the required timeframe is specified in (8)(a) so the term should be deleted.

<u>IPANM proposes to delete paragraphs A(3) through (9) in their entirety:</u>

NMED had proposed a requirement in Section 112 that owners and operators install an EMT on certain equipment, as a subset of a universal set of requirements applicable to all owners and operators of sources of emissions subject to emissions standards and other requirements of Part 50. Section 112(A)(3)-(9) outlines the equipment data and monitoring information that is required to maintained for each source subject to Part 50. [See IPANM SOR 108-126 for additional information about the now-deleted EMT requirement.]

Section 112(A)(9) requires owners and operators, upon request from the Department, to retain a third party at the owners' or operators' expense to verify any information collected, reported, or recorded pursuant to Part 50. The Department stated that third-party verification will conserve the Department's time and resources while also improving public confidence. Proposed Section 112(B) specifies general monitoring requirements for sources subject to Part 50. The monitoring options presented by NMED require frequent monitoring, and while they have been used in refineries and major facilities, IPANM is unaware of these uses in unmanned dispersed sites in an upstream oil and gas region. IPANM Ex. 4 at 5:7-22 (Brown Direct). Small businesses do not have the financial resources to implement these monitoring functions, and nor are those monitoring functions practical in conditions where upstream oil and gas activities occur. *Id*. IPANM maintained that NMED provided no evidence that implementing EMT would have any effect on reducing NOx and VOC emissions. IPANM Ex. 11 at 4:2-6 (Brown Rebuttal). IPANM also maintained that the CDR requirement should be removed from Part 50 because it is cost prohibitive. IPANM Ex. 11 at 6:17-7:5 (Brown Rebuttal).

IPANM also objected to NMED's proposal requiring owners or operators of sources subject to Part 50 to retain a third-party to verify data or information collected. IPANM explained that the third-party audit is costly and does not demonstrate reductions in emissions of ozone precursors. IPANM Ex. 11 at 9:2-14 (Brown Rebuttal). IPANM requested deletion of the EMT requirement in Sections 112-114, 117-119, and 122-123, and the removal of the CDR requirement in Section 112(A)(6)-(7), and the requirement for an operator to retain third party to verify data (audit). IPANM Ex. 11 at 2:4-14 (Brown Rebuttal).

NMED withdrew the proposed requirement to place a physical tag on each affected source (the EMT requirement) throughout Part 50, but kept the requirement to establish a database system to maintain compliance and general information. *Id*. at 4-6; Tr. Vol. 5, 1357:3-5 (Bisbey-Kuehn). NMED did not agree to remove requirements that each monitoring event be contemporaneously recorded and uploaded to the database system. *Id*. at 23:7-8. NMED did not agree with IPANM's proposal to remove the requirement in Section 112(A)(9) that an owner or operator retain a third party to review a CDR to verify compliance with the rule. NMED Rebuttal Ex. 1 at 24:4-14 (Bisbey-Kuehn/Palmer Rebuttal). The Department, however, agreed to limit third-party verification requests to once per year and to add authorization for owners and operators to request a hearing for review of the Department's asserted cause for requesting an audit. *Id*. at 24:14-19; Tr. Vol. 5, 1359:20-21; Tr. Vol. 5, 1360:15-21 (Bisbey-Kuehn). The owner or operator may challenge the recommendations made by the third-party auditor. Tr. Vol. 5, 1361:6-13. NMED retained its proposal to require a database system for date- and time-stamping monitoring events under Section 112. Tr. Vol. 5, 1357:16-17; 1359:10-14. NMED explained that it did not evaluate the cost of the date- and time-stamp technologies, but testified that it hopes to identify free technological "apps" that can perform that function. Tr. Vol. 5, 1369:4-8, 15-19 (Bisbey-Kuehn). See IPANM SOR, pp. 23-26.

NMOGA adds: While the Department is no longer proposing the impracticable EMT system, various section of 20.2.50 NMAC continue to require owners and operators to record a date and time stamp, including a GPS display of the location, for certain monitoring events. The Department has committed to identify acceptable technologies within one year. In identifying these technologies, NMED has indicated it will engage with stakeholders and solicit and incorporate feedback. The Board should memorialize this commitment in the regulatory language or statements of reason. In its most recent proposal, the Department has also granted industry two years from the date technologies are identified to finalize implementation. NMOGA asks the Board to adopt this extended timeline, which is responsive to voluminous testimony concerning the impracticality of integrating technologies for an entire industry within a shorter timeframe.

Specifically, under various sections of Part 50, owners and operators must record a date and time stamp, including a GPS display of the location, of monitoring events. By January 1, 2023, the department has proposed to finalize and post a list of approved technologies to comply with date and time stamp requirements. Owners and operators would be required to comply with this requirement using an approved technology by April 1, 2023. Prior to this date, owners and operators are required to keep a written or electronic record of the date and time of any affected monitoring events. The regulated community has significant concerns about this process and what will ultimately be required, ranging from uncertainty about whether the identified technologies will be compatible with existing systems to anxiety about establishing a robust, expensive system to perform one or fewer monitoring events per year. Importantly, the Department has committed to identify these technologies through a process that solicits and incorporates the feedback of stakeholders. Bisbey-Kuehn Testimony, Tr. 5:1358:24-25 - 1359:1-9. This stakeholder process is essential to ensuring that the identified technologies meet the stated goals without imposing undue burden on regulated entities. Despite the importance of the stakeholder process and the Department's commitment, 20.2.50.112.A(8)(b) NMAC simply states that the "department shall finalize a list of approved technologies" without any mention of soliciting or incorporating stakeholder input. We believe this is an oversight. NMOGA asks the Board to memorialize this commitment to engage with stakeholders in the statement of reasons and/or regulatory language to ensure that the identified technologies reflect the input of regulated entities.

In addition, the Board should grant industry at least two years to implement the approved technologies. As Ms. Kuehn and others testified, database development projects often take years. Kuehn testimony, Tr. 5:1370:3-8. The record indicates that technologies cannot be integrated into industry's database systems quickly and that additional time is needed. Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11.

Beyond this remaining concern, the Department has made several crucial adjustments to 20.2.50.112 NMAC, and NMOGA urges the Board to adopt these revisions. The Department has modified the requirement to comply with manufacturer specifications to allow owners and operators to rely on "an alternative set of specifications, maintenance practices and schedules sufficient to operate and maintain such sources in good working order, which have been approved by qualified maintenance personnel based on engineering principles and field experience." 20.2.50.112.A.1 NMAC; Kuehn testimony, Tr. 5:1356:6-16. This adjustment was made in response to voluminous testimony, which confirmed that reliance on alternative specifications provide needed flexibility without negatively impacting environmental outcomes. *See, e.g.*, NMOGA Exhibit A1, 15:13-25. The Department has modified the annual reporting requirement under 20.2.50.112.D NMAC to address credible concerns prompted by prior iterations. Owners and operators would be required to annually generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of Part 50 at the time the CDR is prepared and keep the report on file for five years. 20.2.50.112.D NMAC. Previously, the reporting language implied that an annual compliance certification requiring significant review, man hours and resources would be required, which various witnesses testified would be overly burdensome. Smitherman testimony, Tr. 5:1429:14-5:1430:14; Cooper testimony, Tr. 5:1492:7-5:1493:3. The Department's most recent proposal is responsive to these credible concerns and provides an adequate metric of compliance assurance.

While WEG and others testified that additional "deviation" reporting is necessary, these witnesses failed to demonstrate that the benefit of this reporting would outweigh the burden it would impose on both NMED and industry. Copeland testimony, Tr. 5:1456:24 -5:1457:23. WEG also did not address the Department's concerns that it could not accommodate substantial additional reporting. As Mr. Baca testified, this proposal would "overwhelm" the Department," "impose additional burdens that are without any public health benefits," and take the Department and industry away from the more important work of "addressing issues with compliance that have to do with emissions to the atmosphere." Tr. 5:1592:15; 1593:8-13.

<u>WEG proposes a new section A(12):</u>

(12) In permitting a stationary source subject to this Part pursuant to 20.2.72, 20.2.74, or 20.2.79 NMAC, the department shall deny any application for a permit or permit revision, including any general permit registration, where construction or modification will cause or contribute to air contaminant levels in excess of ninety-five percent of any primary National Ambient Air Quality Standard for ozone. Compliance with this Part does not demonstrate that a stationary source will not cause or contribute to exceedances of any National Ambient Air Quality Standard or New Mexico ambient air quality standard.

<u>WEG:</u> Guardians proposes to add a standard to the proposed regulations that prohibits air quality permits or permit revisions for oil and gas facilities that would cause or contribute to ozone levels that exceed 95% of the NAAQS. The people of New Mexico, through the state legislature, directed the Board to prevent air quality in the state from exceeding 95% of the NAAQS for ozone, and for good reason. § 74-2-5.C. High levels of ozone pollution have serious health consequences for New Mexicans and especially for children, the elderly, and those with existing vulnerabilities like asthma, allergies, and other respiratory disease. See 85 Fed. Reg. 87256, 87268-87275; see also NMED Ex. 1

at 2. Moreover, high levels of ozone also risk costly regulatory burdens for New Mexico, as NMED witness, Mr. Baca, explained. TR1 352: 3-17. Violations of the ozone NAAQS in New Mexico could lead the EPA to designate portions of the state as "nonattainment areas" – a designation that carries with it additional regulatory burdens. Id.

Although the Part 50 rules proposed by NMED will hopefully help to restore air quality in southeast and northwest New Mexico to below 95% of the NAAQS for ozone, there is no guarantee the rule will achieve this, particularly as oil and gas production and development continues to boom in the state. TR1 352: 21-25; see also WEG Exh. 14. Moreover, it will take years in some cases before the new requirements of the rule are fully implemented. For example, full implementation of the requirements for non-emitting pneumatic controllers will not be complete until January 2030. Proposed Part 20.2.50.122, December 16, 2021 Version. Full implementation of the new rules is not guaranteed either, considering the widespread and systemic compliance issues NMED has identified at oil and gas facilities throughout the state and the Department's under-staffed Compliance and Enforcement Section. TR2 526: 25, 527: 1-19, 531: 6-10, 533: 22-23; 557: 22-25, 558: 1-7 Between now and the hoped-for full implementation of the proposed rules, New Mexicans will continue to suffer the impacts of respiratory disease, asthma, and allergies caused or exacerbated by high levels of ozone pollution. Considering all this, the Board should adopt Guardians' proposal because it would help prevent air quality in New Mexico's most ozone-burdened communities from further deteriorating in the interim period in which the proposed Part 50 is implemented, if approved, and due to the continued oil and gas boom in New Mexico.

New Mexico law and regulation already prohibit air quality permits for facilities that would cause or contribute to exceedances of the ozone NAAQS. This is a fundamental and well-established component of New Mexico air pollution law as well as the Clean Air Act's framework for addressing and preventing harmful air pollution. As such, both NMED and oil and gas operators have long-standing and established practices and processes for addressing this legal requirement.

Guardians derived its proposal from NMED's existing and fundamental authority under New Mexico law and the Clean Air Act to deny air quality permits for facilities that would cause or contribute to exceedances of the ozone NAAQS. See e.g. § 74-2-

7.C.(1)(b); see also 20.2.72.208D. NMAC. Guardians tailored its proposal to meet the New Mexico Legislature's directive to prevent ozone levels from exceeding 95% of the NAAQS. NMED's witness, Mr. Baca, testified that he does not support Guardians' proposal because it would be different, in some ways, to how the Clean Air Act currently authorizes emissions from air polluting facilities, see TR5 1590: 4-14, but that's the whole point of this rulemaking – the way the Clean Air Act currently authorizes air pollution is not adequately protecting New Mexicans from ozone. See NMED's Statement of Reasons, No. EIB 21-27 (R) at 7. In response to deteriorating air quality, the people of New Mexico directed this Board to view the Clean Air Act as a starting point – not an end in itself – for the regulations needed to protect public health in the state. See § 74-2-5.D.(1) ("Rules adopted by the environmental improvement board or the local board may: (1) include rules to protect visibility in mandatory class I areas to prevent significant deterioration of air quality and to achieve ambient air quality standards in nonattainment areas; provided that the rules shall be at least as stringent as required by the federal act and federal regulations pertaining to visibility protection in mandatory class I areas, pertaining to prevention of significant deterioration and pertaining to nonattainment areas…") (emphasis added). See id. at 4-5. This approach promulgated by the New Mexico Legislature was a response to circumstances unique to New Mexico, such as the oil and gas boom, which warrant regulations that differ from and exceed the baseline set by the Clean Air Act. Id. The statute requiring this Board to develop new rules to control ozone precursors, in the case of a determination that air quality exceeds 95% of the NAAQS for ozone, is another example of how New Mexico air quality law can and does differ from the Clean Air Act. The Board should incorporate Guardians' proposal to achieve the Legislature's objective to prevent ozone from exceeding 95% of the NAAQS and begin to restore air quality in the interim period, when the proposed Part 50 rules, if approved, have not been fully implemented.

Mr. Baca and 3 Bear Delaware Operating – NM, LLC's witness, Lori Marquez, expressed concern that Guardians' proposal could impact NMED's workload for facilities permitted as minor facilities or under the General Construction Permit, but these concerns ignore this Board's minor facility precedent. According to this Board, minor facilities and facilities permitted under the General Construction Permit for oil and gas facilities by definition do not cause or contribute to exceedances of the NAAQS for ozone in the Permian Basin. See TR5 1589: 6-20. As Guardians' witness, Jeremy Nichols, testified, under Guardians' proposal, permits for these facilities would only be prohibited, if NMED concluded that they would cause or contribute to ozone levels in excess of 95% of the NAAQS. Id. at 1518: 7-12. Contrary to Mr. Baca's and Ms. Marquez' claims, approval of Guardians' proposal would not impact NMED's workload, given this Board's prior rulings regarding minor sources.

Mr. Baca and Ms. Marquez also opined that Guardians' proposal was outside the scope of the rulemaking, but the statute governing this rulemaking and the stated purpose of the rulemaking noticed to all interested parties do not preclude Guardians' proposal from being considered by the Board. When ozone concentrations are determined to be in excess of 95% of the NAAQS, the New Mexico Legislature directed this Board to adopt "a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance of the standard." § 74-2-5.C. Guardians' proposal prohibiting facilities emitting ozone precursors that would cause or contribute to ozone concentrations in excess of 95% of the NAAQS for ozone falls well within this legislative directive. Furthermore, the public notice for this rulemaking more than adequately notified interested parties of the purpose and scope of this rulemaking, sufficiently placing interested parties on notice of rule proposals such as the one proposed by Guardians. The public notice states: "The purpose of the public hearing is for the Board to consider and take possible action on a petition by NMED requesting the Board to adopt a plan, including proposed new regulations at 20.2.50 NMAC…The proposed regulations at Part 50 would reduce emissions of ozone precursor pollutants (oxides of nitrogen and volatile organic compounds) from sources in the oil and gas sector located in areas of the State within the Board's jurisdiction that are experiencing elevated ozone levels." NMED Exh. 112 at 3. Guardians' proposal to reduce emissions of ozone precursors by prohibiting facilities that cause or contribute to ozone concentrations in excess of 95% of the NAAQS falls squarely within the scope of this rulemaking.

Finally, Mr. Baca also claimed that the AQCA and the Board's regulations limited the grounds on which the Department can deny permits for oil and gas facilities, and that Guardians' proposal would be inconsistent with these limitations. However, Mr. Baca acknowledged that the Department may deny an air quality permit that fails to comply with any statute or rule pursuant to the AQCA. Mr. Baca also admitted that if the Board were to approve Guardians' proposal, it would become a rule pursuant to the AQCA, pursuant to which the Department could deny an air quality permit. Accordingly, Guardians' proposal, if approved, would be consistent with the rules governing the Department's authority to deny permits.

<u>NMED opposes WEG's proposal:</u> This proposal would require the Department to deny any permit application where the source would cause or contribute to air contaminant levels in excess of ninety-five percent of the ozone NAAQS. The Department opposed WEG's proposed revision pertaining to permitting. Mr. Baca testified that this proposal is not within the scope of this rulemaking, and is not technically feasible or practical to implement. First, the purpose of the Part 50 is to set emission standards for oil and gas sector equipment and processes, regardless of the permitting status for such equipment and processes. Adopting permitting provisions into this rule is not appropriate at this time, as the consequences of such a revision to New Mexico's permitting program require a full evaluation, including a public comment period for the regulated community and interested stakeholders, as well as discussions with the U.S. Environmental Protection Agency to identify the implications for New Mexico's SIP if such revisions were adopted. The breadth of such a change would best be addressed through a separate rulemaking process and public notice since it is outside of the original scope of the proposed rule. *See* NMED Rebuttal Exhibit 22, pp. 3-4.

Second, the Board and the Department derive their authority to carry out their duties from the enabling statutes that are passed into law by the New Mexico Legislature, including the Environmental Improvement Act, NMSA 1978 74-1-1 to -17, and the AQCA, NMSA 1978, 74-2-1 to -17. As the designated air pollution control agency for the State, the Department must ensure that its SIP, and by extension its regulatory programs, are operated consistent with the federal Clean Air Act and implementing regulations. This includes the Department's air quality permitting program and the Board's regulations implementing that program, including the following: 20.2.72 NMAC – *Construction Permits*; , 20.2.74 NMAC – *Permits – Prevention of Significant*

Deterioration; and 20.2.79 NMAC – *Permits – Nonattainment Areas*. Additionally, Section 74-2-7(C) of the AQCA specifies that circumstances under which the Department may deny a permit; there is no authority provided for the Board to specify by regulation additional bases for denial of permits. While the statute allows the Department to deny a permit where it will cause or contribute to air contaminant levels in excess of ***the NAAQS***, it does not provide authority to the Department to deny a permit where it will cause or contribute to air contaminant levels in excess ***of ninety-five percent*** of a NAAQS. The Board's regulations relating to air quality permits must be in line with the statute, otherwise they are vulnerable to legal challenges. *Id.* at 4.

Furthermore, these state statutes and permitting rules have been fully approved by EPA as part of New Mexico's SIP, and give the Department the ability to implement the Clean Air Act in New Mexico on behalf of the federal government. Denying permits contrary to the AQCA and the State's approved SIP endangers the ability of New Mexico to run its own air quality program and issue permits. The Department has not been notified by EPA that any part of its permitting program is inconsistent with the approved SIP or federal law. *Id.* at 5. The Board should reject WEG's proposal for the reasons stated in NMED Rebuttal Exhibit 22, pp. 3-5.

<u>CDG opposes WEG's proposal:</u> WEG proposed to add a new paragraph within Subsection A of 20.2.50.112 requiring NMED to deny applications for permits or permit revisions, including general construction permit registrations, where construction or modification would cause or contribute to ozone concentrations in excess of 95% of any primary National Ambient Air Quality Standard. NMED appropriately declined to add this prohibition to Subsection A of 20.2.50.112.

WEG did not demonstrate that its proposal would reduce emissions, provided no estimate of its costs or benefits, and did not show that its proposal could be successfully implemented. The proposal would disrupt the NMED's permitting program by restricting the use of general construction permits in designated attainment areas. The proposal could require individual minor sources to model their single-source ozone impacts. However, this process is not economically feasible and is intentionally not required under current regulations. The proposal would also conflict with federal law by preventing the issuance of Nonattainment Area New Source Review permits to applicants who generate or acquire emissions offsets. Thus, WEG's proposal should not be part of the Rule. See CDG NOI Rebuttal Testimony: Lori Marquez, pgs. 1-11.

(10) Where Part 50 refers to applicable federal standards or requirements, the references are to the applicable federal standards or requirements that were in effect at the time of the effective date of this Part, unless the applicable federal standards or requirements have been superseded by more stringent federal standards or requirements.

NMED: Paragraph (10) of Subsection A of Section 20.2.50.112 clarifies that where Part 50 refers to an applicable federal standard or requirements, the references refer to the applicable federal standards or requirements that were in effect at the time of the effective date of this Part. The Department is proposing additional language to clarify its intent in this provision to guard against situations where referenced federal standards are repealed or amended to be less stringent. The Board should adopt this provision because it is necessary to ensure that the department, regulated parties, and the public clearly understand which federal standard or requirement that the Department was referencing during the development of this Part. If those federal standards or requirements are revised in the future, it also clarifies which version of those requirements should be complied with. NMED Rebuttal Exhibit 1, pp. 24-25.

(11) Prior to modifying an existing source, including but not limited to increasing a source's throughput or emissions, the owner or operator shall determine the applicability of this Part in accordance with 20.2.50.111.B NMAC.

NMED: Paragraph (11) of Subsection A of 20.2.50.112 requires owners or operators to review Part 50 for applicability prior to modifying an existing source. The Board should adopt this proposal because it is necessary to ensure that owners and operators know of their regulatory obligation to review and confirm applicability or non-applicability of Part 50 when modifying sources that may become subject to Part 50 as a result of such modifications. NMED Rebuttal Exhibit 1, p. 25.

B. Monitoring requirements: In addition to any monitoring requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:

(1) Unless otherwise specified, the term monitoring as used in this Part includes, but is not limited to, monitoring, testing, or inspection requirements.

(2) If equipment is shut down at the time of periodic testing, monitoring, or inspection required under this Part, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

NMED: Subsection B of Section 20.2.50.112 specifies general monitoring-related requirements applicable to sources subject to Part 50. Paragraph (1) clarifies what is meant by the term "monitoring" as used throughout the rule. Paragraph (2) provides direction regarding how to comply with monitoring requirements when equipment is shut down at the time of required periodic testing, monitoring or inspection. NMED added language in response to comments from NMOGA allowing an owner or operator's authorized representative to conduct requiring monitoring activities. NMED is proposing to remove the provision formerly included at Paragraph (3) addressing submission of an alternative monitoring strategy under Section 20.2.50.116 because such submissions are already addressed in Section 20.2.50.116, making the provision in 20.2.50.112 redundant and unnecessary. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 27; NMED Rebuttal Exhibit 1, pp. 25-26.

Kinder Morgan: During the hearing, the Department determined to strike an earlier version of 20.2.50.112.B.(2) NMAC requiring monthly monitoring. See Closing Argument, at 22-23. The Department reasoned that, because (1) each section of the Proposed Rules contains specific monitoring requirements for that particular equipment or process, and (2) the general monitoring requirement set forth in Section 112 was not intended to be something unique from the other monitoring required in the Proposed Rules, the Department determined it was appropriate to remove the general provision and rely on the monitoring schedules required in each section. The Department reflects these positions in this January 18 Draft. This deletion adds clarity that is necessary for implementation, and Kinder Morgan asks the Board to adopt this provision as drafted.

NMOGA, in B(1), adds as a second sentence:

"Unless otherwise specified in this Part, monitoring is required to commence upon the date that the associated control requirements become effective."

NMOGA: This is a complex rule and it is possible that NMED and NMOGA have missed a monitoring applicability date. NMOGA proposes this "general" applicability date for monitoring in case there are any sections where the start date for monitoring is not specified clearly. The proposed language corresponds to general air pollution control practice.

C. Recordkeeping requirements: In addition to any recordkeeping requirements specified in the applicable sections of this Part, owners and operators shall comply with the following:

(1) Within three business days of a monitoring event and when final reports are received, an electronic record shall be made of the monitoring event and shall include the information required by the applicable sections of this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years.

(3) By July 1 of each calendar year starting in 2024, the owner or operator shall generate a Compliance Database Report (CDR) on all assets under its control that are subject to the CDR requirements of this Part at the time the CDR is prepared and keep this report on file for five years.

NMED: Subsection C of Section 20.2.50.112 establishes minimum universal recordkeeping requirements that owners and operators of sources subject to Part 50 must comply with in addition to the specific monitoring requirements in the applicable sections of the rule. Paragraphs (1) and (2) require that owners or operators make an electronic record of a monitoring event within three business days of the event and to maintain all records required under this part for at least five years. Paragraph (3) requires owners and operators to conduct an annual compliance review for each affected source and certify compliance with all terms and requirements of Part 50. Such certifications must be retained onsite for the specified timeframes.

This provision replaces NMED's original proposed requirement that owners and operators complete a fully compliance evaluation prior to any transfer of equipment subject to Part 50. NMED agreed with industry parties' proposals to remove that provision. The annual compliance certification is essential to ensuring compliance with

Part 50. *See* Tr. Vol. 5, 1377:2 – 1378:3; 1584:22 – 1585:4. Ms. Kuehn testified that this compliance certification was not meant to be an environmental audit, and it should not require extensive additional resources so long as owners and operators are complying with the monitoring and recordkeeping requirements of Part 50. *See* Tr. Vol. 5, 1583:20 – 1584:21. The annual compliance certification simply requires that such data be complied into an annual report. Ms. Kuehn also testified that the Department would provide a template in the form of an Excel spreadsheet to assist smaller companies in complying with the data system and annual compliance report requirements. *See* Tr. Vol. 5, 1362:9 – 1364:12, 1371:8 – 1374:6, 1378:3-17, 1582:14 – 1583:18, 1586:3-23. NMED agreed to strike the provision in Subsection C that required monthly inspections, and instead rely on the monitoring requirements in each section of the rule. *See* Tr. Vol. 5, 1586:25 – 1587:21. NMED also agreed to remove the provision stating loss of data or failure to keep a record shall be treated as a failure to collect the data, because the Department is already able to do this within its enforcement authority. *See* Tr. Vol. 5, 1363:4-8. The Board should adopt this proposal for the reasons stated above and in NMED Exhibit 32, pp. 29-30 and NMED Rebuttal Exhibit 1, pp. 26-27.

NMOGA: As to Section C(3), NMOGA agrees with NMED and appreciates NMED's clarification of the annual reporting requirement. The proposed language is consistent with the concerns and recommendations made by Mr. Smitherman. Smitherman testimony, Tr. 5:1429:14-5:1430:14. *See also* Cooper testimony, Tr. 5:1492:7-5:1493:3.

D. Reporting requirements: In addition to any reporting requirements specified in the applicable sections in this Part, the owner or operator shall respond within three business days to a request for information by the department under this Part. The response shall provide the requested information for each source subject to the request by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request. If the department requests a CDR from multiple facilities, additional time will be given as appropriate. [20.2.50.112 NMAC - N, XX/XX/2021]

NMED: Subsection D of Section 20.2.50.112 establishes general reporting requirements for sources subject to Part 50. Owners and operators are required to provide requested information to the Department within 3 business days of the request. The requested information must be provided by electronically submitting a compliance data report through the Department's Secure Extranet Portal or by other means and formats specified by the Department in its request. The Department agreed to revisions specifying that additional time will be provided if the department requests a CDR from multiple facilities. The Board should adopt this proposal for the reasons stated at NMED Exhibit 32, p. 30 and NMED Rebuttal Exhibit 1, p. 27.

<u>GCA:</u> The GCA supports the NMED's proposed requirement in 20.2.50.112(D) that an owner or operator respond within three business days to a request for information under 20.2.50. This deadline will ensure that the CDR is promptly generated and submitted to the Department while largely alleviating the potential compliance challenges associated with a 24-hour reporting deadline. GCA Exhibit 15 (Copeland Direct) at 21. [For more details in Mr. Copeland's testimony, see GCA Closing Argument pp. 19-20 and proposed SOR 10-13.]

<u>NMOGA:</u> NMED agreed that it "will" give additional time if multiple facility CDRs are requested. Bisbey-Kuehn testimony, Tr. 1374:10-25. In addition, to the extent that WEG and others believe that additional "deviation" reporting is necessary, the benefits of that reporting are unclear, and they impose significant additional costs and burdens on both NMED and industry. Copeland testimony, Tr. 5:1456:24-5:1457:23. NMOGA dislikes the requested expansion in the Department's January18, 2022 redline because it extends beyond the CDR. If limited to the CDR, NMOGA takes no exception. If extended beyond the CDR, there is no evidentiary record to support whether such information could be produced in such a short time frame.

<u>IPANM proposes to delete Section D in its entirety</u>: The compliance database system provision requires final reports to be entered within three business days and that the Department will develop a list of approved technologies for the "new contemporaneous tracking system." The third-party audit relates to data and information that is prepared in the database report that the Department may request under the proposed Ozone Rule. NMOGA commented, however, that the CDR is a complex and challenging report to compile, depending on the complexity of an operator's information system; it will require

written codes and database integration for completion of the report. Tr. Vol. 5, 1426:14-22 (Smitherman). IPANM and CDG also stated that the generation of the CDR is cumbersome. Tr. Vol. 5, 1436:23-1437:3 (Brown) and 1469:22-1470:1 (Marquez).

IPANM also pointed out that operators will have to comply with the GPS and date- and time-stamp requirements on April 2, 2023, but that they will not receive a list of approved technologies until January 1, 2023. Tr. Vol. 5, 1437:4-15 (Brown). IPANM further explained that the submission and date- and time-stamp data requires a mobile application for that data to be uploaded into web-based software. Tr. Vol. 5, 1437:22-1428:1 (Brown). This process is time-intensive, expensive, and will require the services of outside consultants for members of IPANM. Tr. Vol. 5, 1438:2-10 (Brown). Small companies with limited well production will face difficulties with developing a compliance database system if they have not uploaded their data to a central data server or do not have one in place. Tr. Vol. 5, 1439:12-17 (Brown). IPANM also requested a compliance database exception for companies that have limited reporting requirements; in lieu of a database, they may produce a written or electronic record of the data and time of the affected monitoring event. Tr. Vol. 5, 1439:18-1440:12 (Brown).

While IPANM lauded the Department's efforts to investigate the compliance reporting systems that some operators may already have in place, four months is not enough time for operators to comply with the implementation of Section 112. Tr. Vol. 5, 1438:2-8 (Brown). IPANM requested that Section 112 be implemented after January 1, 2025. Tr. Vol. 5, 1439:9-11 (Brown). The Department agreed to extend the timeframe to implement the GPS and date- and time-stamp requirements. Mr. Brown also testified that the third-party audit would require the dedication of company resources and employees to assist the auditor and could interfere with their normal business and responsibilities. See Tr. Vol. 5, 1441:1-6 (Brown).

The third-party audit relates to data and information that is prepared in the database report that the Department may request under the proposed Ozone Rule. IPANM proposed that a third-party audit be conducted only in cases of probable extensive noncompliance. Tr. Vol. 5, 1441:7-9 (Brown). NMED responded that it is inappropriate for the certification to address only major instances of noncompliance, as the intent is to compile monitoring records of the owner and operator requirements outlined in Part 50. However, NMED's rationale overlooks companies that have limited reporting capabilities. Tr. Vol. 5, 1439:18-1440:12 (Brown). The Department, nevertheless, stated that entities meeting the criteria of a small business facility are not required to prepare a CDR. When queried by Chair Suina regarding industry's concerns about additional costs brought about Section 112, the Department dismissed them, stating that demonstrating compliance is essential to meeting emission standards. *See* Tr. Vol. 5, 1377: 6-9, 17-22 (Bisbey-Kuehn). When questioned by Vice-Chair Trujillo-Davis about whether it is the intent of the Department for operators to hire more employees dedicated to inspections, the Department confirmed that it "may be the reality" that hiring employees may be necessary for some owners and operators. *See* Tr. Vol. 5, 1377: 18-25 (Bisbey-Kuehn). The Department intends to hire contractors that will develop a template to assist small operators with database management. Based on the evidence presented, the Board should find that the EMT requirement, CDR requirement, and third-party audit provision are each overly burdensome and unnecessary for compliance and should each be removed from Part 50. See IPANM SOR, pp. 26-29.

WEG proposes to add two paragraphs to Section D:

D. Reporting requirements:

(1) The owner or operator shall submit records of all monitoring events documenting deviations of this Part to the department. For excess emissions, reports shall be submitted in accordance with 20.2.7 NMAC. For all other deviations, reports shall be submitted semi-annually beginning January 1, 2022 and shall be submitted by the 30th day of the month following the end of each semi-annual period.

……..

(3) The owner or operator shall comply with all applicable reporting requirements at 20.2.7 NMAC.

WEG: Guardians proposes that the Board adopt provisions that require owners and operators to submit records that document deviations or noncompliance with monitoring and other requirements set forth in the proposed Part 50 regulations. While New Mexico already requires owners and operators of oil and gas facilities to self-report excess emissions to NMED pursuant to 20.2.7 NMAC, Guardians' proposal would require operators to report deviations from the work practice standards and other requirements in Part 50, beyond excess emissions.

The regulations proposed by NMED in Part 50 include, for example, a variety of new monitoring requirements that seek to prevent excess emissions from happening in the first place. For instance, the proposed Part 50 regulations would require operators of the largest oil and gas facilities to conduct, at minimum, weekly external audio, visual, and olfactory inspections of various facility components to prevent equipment leaks before excess emissions occur. (Proposed Part 20.2.50.116C.(1), December 16, 2021 Version.) The objective of this rule provision – to prevent excess emissions – cannot be achieved unless operators actually comply with the monitoring requirements. As a result, NMED's proposed Part 50 also requires operators to maintain records of their compliance with monitoring requirements like these. However, under NMED's current rule proposal, operators are not required to report these records to NMED unless specifically requested. (Proposed Part 20.2.50.112A.(3), December 16, 2021 Version (stating "Within two years of the effective date of this Part, owners and operators of a source requiring equipment monitoring, testing, or inspection shall develop and implement a data system(s) capable of storing information for each source in a manner consistent with this section.").) Guardians' proposal would simply require that when operators record instances of deviations or noncompliance with requirements of Part 50, operators must report this to NMED on a semi-annual basis.

NMED's witness, Ms. Hollenberg, testified at length about how important it is for NMED to receive reports and data indicating compliance issues at oil and gas facilities. TR2 530: 23-24 (testifying "Reliance on self-reporting is integral to the Bureau's compliance and enforcement strategy."). As discussed above, understaffing at the Compliance and Enforcement Section is a constant problem and particularly so since 2019. TR2 558: 2-7 (testifying "I would say that – that we do – we have had a significant number of vacancies since at least 2019. In 2019, at that point I was inspections manager and we were fully staffed at seven inspectors, and that didn't last very long. So, yes, there are resource constraints on an ongoing basis."). As a result, NMED cannot conduct all the inspections of oil and gas facilities that are legally required throughout the year. TR2

531: 6-8 (testifying "Well, it's pretty clear that the Bureau does not have adequate staff to inspect every facility in New Mexico.").

Absent sufficient inspection capacity, Ms. Hollenberg testified that NMED has and will continue to rely on self-reported compliance data to ensure operators are complying with the rules. TR2 531: 8-9. Without this compliance data, NMED's Compliance and Enforcement staff would have far less information to identify serious violators and other compliance trends across the state. TR2 543: 17-25, 544: 1-3 (testifying "So what this will help us do is gather the information that would be impossible for us to gather on our own. And the way that that will work, of course, remains to be seen, but without that information, just like if there were no excess emissions reporting required, we would have nothing to go on. This at least give us something to go on, so that when we do our required inspections, when we do our required reports reviews, we have more information that helps point us in the direction of where we need to really focus our efforts so that we can get to that level – level playing field as much as possible").

As Ms. Hollenberg testified, NMED's proposed Part 50 already requires that operators record their compliance, or noncompliance, with the requirements in Part 50. However, under the current version of the proposed Part 50, operators are not required to report their deviations or noncompliance with Part 50 to the Department unless requested to do so. The Department's witness, Ms. Bisbey-Kuehn, admitted that as Part 50 is currently written, the Compliance and Enforcement Section would not receive any of this compliance data unless the Department specifically requested it. TR5 1376: 17-21. And as Ms. Hollenberg testified, NMED already lacks the staff necessary to conduct required facility inspections, much less request compliance reports for the thousands of oil and gas facilities across the state.

Guardians' proposal is a balanced approach that would provide NMED's Compliance and Enforcement staff critical information necessary to preventing excess emissions but without creating administrative burdens that NMED and operators are not already prepared to address. As discussed above, NMED's proposed Part 50 already requires operators to compile the compliance data that, under Guardians' proposal, would need to be reported to NMED. In addition, rather than require operators to report the entirety of that compliance data to NMED, Guardians' proposal only requires operators to report deviations, in other words noncompliance, with Part 50 to NMED. Operators of many oil and gas facilities currently self-report excess emissions pursuant to 20.2.7 NMAC, and NMED has been competently receiving that data for years now. A requirement obligating operators to report deviations or noncompliance with the provisions in Part 50 should, therefore, not be overly burdensome given established self-reporting tools and the fact that operators are already obligated under the proposed Part 50 rules to monitor and record this information.

Importantly, an operator that fully complies with Part 50 will have nothing to report to NMED according to Guardians' proposal, as NMED's witness, Mr. Baca, admitted. TR5 1596: 7-15. Guardians' proposal only requires owners and operators to report deviations to NMED. Despite Mr. Baca's admission, he testified that NMED would be over-whelmed by Guardians' reporting proposal. TR5 1592: 9-18. Mr. Baca's concern troublingly implies that he assumes New Mexico oil and gas operators will have significant noncompliance issues to report to NMED under the proposed Part 50 rules. But if New Mexico oil and gas owners and operators are not going to significantly comply with the rules proposed in Part 50, it is unclear why the Board, NMED, and other interested parties have undertaken this rulemaking exercise.

Mr. Baca also questioned the benefit of reporting the information contemplated in Guardians' proposal, but Ms. Hollenberg testified clearly that this type of compliance information is critical to NMED's ability to implement and enforce its air quality regulations, particularly given low staffing levels. Besides, Mr. Baca admitted that if he were a homeowner nearby an oil and gas facility failing to comply with provisions of Part 50, he would want to be aware of that noncompliance. TR5: 1597: 22-25, 1598: 3. Many, if not all, New Mexicans likely share Mr. Baca's interest in being aware of non-compliance issues, but the general public would have no access to an operator's failure to comply with the monitoring, testing, and inspection requirements required by the proposed Part 50, unless operators reported it to NMED, thereby making the compliance data a matter of public record. Guardians' proposal ensures both NMED Compliance and Enforcement staff receive this information and ensures public access to the information.

Finally, in response to a question from counsel for the GCA, Mr. Baca agreed that any deviation that caused an excess emission would be reported to NMED through the current excess emission reporting requirements. However, the rules in proposed Part 50 are about more than reporting excess emissions – the proposed rules seek to ensure compliance with monitoring, testing, and inspection requirements that prevent excess emissions from occurring in the first place. Mr. Baca explained, himself, that with the new requirements in proposed Part 50, NMED is attempting to "address a gap between the excess emission reporting and [] reporting around deviations from, like I said, work practice standards or leak detection and repair, where you don't necessarily have a quantitative excess emission you can report." TR5 1551: 18-23. Mr. Baca went on to testify that NMED wants to ensure that "there's an added layer of reporting required so that the public has a complete picture around a source's compliance status…" TR5 1551: 6-9. But contrary to Mr. Baca's testimony, under NMED's proposal the public would not have a complete picture of an oil and gas facility's compliance status unless and until NMED's under-staffed Enforcement and Compliance Section finds the time to specifically request this information from the relevant operator(s). This is the crux of Guardians' proposal – NMED and the public should have a complete picture of any and all oil and gas facilities that have compliance issues with the new requirements of Part 50, without having to spend the time and resources requesting this information.

<u>NMED opposes WEG's proposal:</u> NMED opposed WEG's proposed language regarding excess emissions and self-reporting of "deviations" from the proposed rule. NMED witness Mr. Baca testified that the term "deviations" is ambiguous and would create unclear expectations and pose implementation challenges. As written, a company would have to report simple and inconsequential deviations from the rule's requirements. Additionally, specific requirements for reporting and correcting deviations from each section would have to be developed. NMED Rebuttal Exhibit 22, pp. 5-6.

The proposed language would also create significant administrative burdens on the Department and the regulated community without commensurate public health protections. Reporting of a "deviation" does not ensure that it is corrected, nor do all deviations result in emissions to the atmosphere. The resources expended by industry to comply with the rule and the Department to enforce it are better spent identifying and addressing problems to ensure compliance with the emission standards and that emissions to the atmosphere are minimized.

Additionally, the proposed changes would require the Department to set up a new system for reporting deviations and processing those reports to determine if a violation has occurred and whether corrective action and enforcement are necessary. The Department simply does not have the resources to design, deploy, and administer such a system. Instead, the rule sets deadlines for completing repairs for faulty equipment or when leaks are detected, and required regulated entities to keep records which can be provided to the Department upon request. *Id.* at 5.

Sources subject to the Board's excess emissions rules at 20.2.7 NMAC are already required to comply with the provisions of that rule independent of any other requirement. Cross referencing this rule in the Part 50 does not provide enhanced compliance incentives for industry, nor does it provide the Department additional tools for increased compliance and enforcement of either rule. *Id.* at 5-6.

Finally, reporting of violations of Part 50 would not provide pertinent health information to the public. NMED provides pertinent data to the public through its ozone monitoring network and emissions reporting requirements. This information is readily available on the Department's website and staff routinely respond to more complex external data inquires and requests for other information through the Inspection of Public Records Act, NMSA 1978, 14-2-1 to -12. Additionally, the Department is proposing to require companies to keep extensive records, including date and time stamped records of monitoring and repair events, and produce a Compliance Data Report at any time upon the Department's request. The request for a CDR may be made for any reason, including in response to public inquiries, complaints, or concerns. Limiting these submittals allows NMED to focus its limited resources on ensuring compliance, instead of administrative record keeping. The Rebuttal Testimony of Cindy Hollenberg included at NMED Rebuttal Exhibit 14, discusses the Department's recent compliance and enforcement activities, including those related to the Oil and Gas sector. *Id.* at 6-7. The Board should reject WEG's proposal for the reasons stated in NMED Rebuttal Exhibit 22, pp. 5-7.

GCA: The GCA supports the NMED's decision not to add WEG's requested semi-annual deviation reporting requirement to the proposed rule. The proposed rule includes significant monitoring, testing, recordkeeping, and reporting requirements that are sufficient for demonstrating compliance with 20.2.50. The compliance self-reporting sought by WEG has only been imposed on "major sources" of air pollutants and not in a state rule that is generally applicable to minor sources. WEG's proposal would impose significant additional burdens on the regulated community by requiring the self-reporting of information already available to NMED. GCA Exhibit 30 (Copeland Rebuttal) at 2-7.

20.2.50.113 ENGINES AND TURBINES:

NMED:

Description of Equipment and Process

Engines and turbines are used in the oil and gas industry to power compressors that maintain natural gas pressures at levels sufficient to move gas through gathering and transmission pipelines. Compressors at gathering compressor stations move the gas from the wellhead to gas processing plants. Compressors at gas processing plants move the gas from the processing plants to transmission pipelines, and compressors at transmission compressor stations maintain pressure and move the gas along the transmission pipelines to the ultimate user of the processed gas.

In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid or may be used as backup power supply in case of a power outage. Engines are also used to drive pumpjacks in the oil production sector. Pumpjacks are used to mechanically lift liquid out of the well if bottom hole pressure is not high enough to allow liquid to flow to the surface.

Two kinds of reciprocating internal combustion engines are used in the oil and gas industry: spark ignition and compression ignition. The work cycle of both types of engines may either be two-stroke or four-stroke. Reciprocating internal combustion engines are generally used to power reciprocating compressors, and often the engine and compressor share the same crankshaft in what is known as an integral compressor.

A combustion turbine consists of an upstream rotating combustion gas compressor, a combustor, and a downstream turbine on the same shaft as the combustion gas compressor. During operation, the combustion turbine compresses atmospheric air and mixes it with fuel that is burned at extremely high temperatures, creating a hot gas. This hot mixture moves through blades in the turbine, causing them to spin quickly. These blades rotate the turbine drive shaft, which powers the combustion gas compressor. NMED Exhibit 32, pp. 31-32

Control Options

Readily available options for controlling NOx on two-stroke and four stroke lean burn engines include low emissions controls, selective catalytic reduction, and non-selective catalytic reduction ("SCR"). Readily available NO_X control options for turbines include water or steam injection, dry low-NO_X burners, and SCR. Readily available VOC control options for engines include NSCR and catalytic oxidation. A readily available VOC control option for turbines is catalytic oxidation. *Id.* at 32-36.

Rule Language

The proposed requirements in Section 20.2.50.113 are based on similar rules and standards for new and existing engines and turbines in Pennsylvania GP-5 and GP-5A; California South Coast Air Quality Management District Rule 1110.2; EPA's regulations at 40 C.F.R. § 63, Subpart ZZZZ; 40 C.F.R. § 60, Subpart JJJJ; Colorado Reg. 7, Part E; PA TSD 2018 (NMED Exhibit 52); and EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) (NMED Exhibit 53). NMED Exhibit 32, pp. 37-46.

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC. Non-road engines as defined in 40 C.F.R. §§ 1068.30 are not subject to 20.2.50.113 NMAC.

NMED: Subsection A of Section 20.2.50.113 states the equipment to which this Section applies. Section 20.2.50.113 applies to portable and stationary natural gas-fired spark ignition engines; compression ignition engines; and natural gas-fired combustion turbines located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations with a rated horsepower greater than those shown in Tables 1, 2, and 3 of Section 113. The Department accepted NMOGA's proposal to expressly exempt non-road engines as defined by federal regulations from this Section because the Clean Air Act preempts state enforcement of emissions standards for such engines. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56, and NMED Rebuttal Exhibit 1, p. 27.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC.

NMED: Paragraph (1) of Subsection B of Section 20.2.50.113 requires owners and operators of new and existing portable and stationary engines and turbines equal to or exceeding specified horsepower ratings to meet certain NOx, CO, and VOC emission limits by certain dates unless otherwise specified under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56, and NMED Rebuttal Exhibit 1, p. 27.

(2) The owner or operator of an existing natural gas-fired spark ignition engine shall complete an inventory of all existing engines subject to this Part by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan (ACP) approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meet the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the

remaining thirty-five percent of the company's existing engines meet the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

NMED: Paragraph (2) of Subsection B of Section 20.2.50.113 requires owners and operators of existing spark ignited engines to develop an inventory of those engines and meet the emission limits over a specified timeline, unless otherwise specified under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. This timeline requires a certain percentage of the inventoried fleet to meet the requirements by specified deadlines. The Board should adopt this proposal because the staggered timeline allows owners and operators sufficient time to come into compliance with the requirements of this Section.

Further, in lieu of meeting the emissions limits, owners and operators may reduce the number of hours of operation in order to reduce emissions to rates similar to the emissions reduction requirements achieved by utilizing emission control devices. The Board should adopt this proposal because it provides flexibility by allowing an alternative method of compliance for engines that are difficult to retrofit, while ensuring equivalent emission reductions. *See* NMED Exhibit 32, p. 36; NMED Rebuttal Exhibit 1, pp. 27-29.

NMOGA provides supporting history: Prior versions of this rule had proposed to regulate "installation" or "relocation." Ms. Kuehn testified that upon further reflection, the Department does not believe this is appropriate and that language was removed. Kuehn/Palmer testimony, Tr. 6:1686:1-6; Lisowski Rebuttal Testimony, NMOGA Exhibit 43, 1:26-2:3; 6:33-7:13. Ms. Kuehn testified that the "parties are largely in agreement with the new emission standards and thresholds that [NMED] established in this rule." Tr. 6:1682:10-13. She later testified that NMED had revised the tables based on some of the other state programs, such as Pennsylvania's GP-5 program, having other exemptions or off-ramps that were not recognized originally or assumed different fuel types or sizes from those in New Mexico. Kuehn/Palmer testimony, Tr. 6:1701:23-

6:1702:5. Mr. Palmer also stated that the department revised the limits based on achievability and cost effectiveness based on the testimony received. Tr. 6:1713:6-11.

Mr. Lisowski outlined the technical bases for why additional LEC is not available, Tr. 6:1725:17-6:1727:7. Mr. Lisowski also explained why certain retrofit technologies are not widely applicable, Tr. 6:1727:11-6:1728:1, limitations of NSCR in the field due to drift and fuel gas variation, Tr. 6:1729:13-6:1730:8, and why SCR is generally not effective for oilfield engines, Tr. 6:1730:9-6:1731:9. Mr. Lisowski's comments were echoed by Mr. Sheldon, Tr. 6:1748:7-6:1749:18, and Mr. Dutton, Tr. 6:1753:15-6:1755:3, both experts introduced by the Gas Compressor Association. Ms. Devore and Dr. Orozco argued that the 2.0 g/bhp-hr should be reduced to 1.2 g/bhp-hr, but Mr. Lisowski testified that this was not achievable as a blanket matter and that "there's going to be a large subset of engines in New Mexico that cannot achieve that target and will need to be replaced." Lisowski, Tr. 9:2993:13-18. Mr. Lisowski also explained why, practically, a lower limit was not achievable even with some engines meeting NSPS in response to a question from Chair Suina. Tr. 9:2999:25-9:3001:11.

NPS proposes a new paragraph B(2)(e):

"Companies shall maintain a plan that demonstrates how the owner or operator will meet the emission standards as outlined in the schedule above."

Table 1 - EMISSION STANDARDS FOR EXISTING NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
2 Stroke Lean Burn	>1,000	3.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	2.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	≥1,775 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich Burn	>1,000 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

NMED: Table 1 of Paragraph (2) sets forth the emission limits for existing natural gas-fired spark ignition engines. The limits originally proposed by the Department and the basis for those limits are set forth in the pre-filed direct testimony of Ms. Bisbey-Kuehn and Mr. Palmer, and were based on standards and data from other states, such as Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, Part E, The California South Coast Air Quality Management District Rule 1110.2, and Ohio EPA test data. *See* NMED Ex. 32, at pp. 37-42. NMED proposes revised emissions limits in Table 1 based on information submitted by NMOGA, Kinder Morgan, and GCA, and a further analysis of stack emissions testing data available from Ohio and the NMED Equipment Data. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Ex. 1, pp. 29-34.

<u>NMOGA supports Table 1</u>: Ms. Kuehn testified that the Table 1 limits are based on the testimony of the parties who filed direct and rebuttal testimony. Tr. 6:1685:20-25. Mr. Lisowski testified extensively as to why the limits were appropriate; a succinct summary is in Lisowksi Rebuttal Testimony, NMOGA Exhibit 43.

After extensive engagement, the Department has proposed reasonable and aggressive standards for existing and new engines and turbines, which reflects the agreement of a diverse group of stakeholders. Bisbey-Kuehn testimony, Tr. 6:1682:10-13. Although the ultimate proposal is not as stringent as the Department's initial petition, it reflects necessary adjustments based on new information provided by various technical witnesses, including the differing field and gas conditions in New Mexico, off ramps and exemptions found in other regulatory programs not previously considered by the Department, and other technical and economic challenges. Bisbey-Kuehn testimony, Tr. 6:1701:23-6:1702:5. For example, many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3. Based upon this testimony and supporting testimony from Mr. Dutton, Mr. Sheldon, Ms. Witherspoon, and NMED, the

Board should find existing and new engine and turbine limits are reasonable and appropriate as proposed by NMED.

The National Park Service in its pre-filed testimony requested that emissions limits be established for smaller engines. Multiple experts testified that the proposed limits were not achievable in a cost-effective manner and urged that they not be adopted. See Trent, Tr. 6:1814:9-16; Sheldon and Dutton, Tr. 6:1757:1-6:1760:13, Lisowski Tr. 9:2990:20-9:2991:20. Based on this testimony, the NPS withdrew its request to regulate the smaller engines. Devore testimony, Tr. 8:2399:24-8:2400:9. The Board should find that establishing emissions limits for smaller engines as originally proposed by the National Park Service is not supported by the record.

NMED's initial proposal applied 20.2.50.113 NMAC to nonroad engines. NMED has since revised its proposal so that proposed 20.2.50.113 NMAC does not apply to this class of engines. The Board should find that excluding non-road engines from 20.2.50.113 is proper as these engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88 F.3d 1075, 1087-88 (D.C. Cir. 1996).

The Department has proposed various measures to add flexibility in meeting emissions limits under 20.2.50.113.B NMAC. These include an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits (20.2.50.113.B(12). Ms. Bisbey-Kuehn credibly testified that these conditions are technically sound, environmentally protective, and provide flexibility to owners and operators. Tr. 6:1690:7-25 - 1693:1-21. The Board should find these changes are supported by the record and the weight of evidence.

The Department has proposed various measures to clarify the monitoring requirements under 20.2.50.113.C. These include the following: equivalency between maintenance conducted consistent with an applicable NSPS or NESHAP and maintenance conducted under 20.2.50.113.C(1) NMAC (20.2.50.113.C(2)); load calculation methodologies (20.2.50.112.C(4)); testing timeframes and procedures consistent with New Source Performance Standards (20.2.50.112.C(4)(a)-(h)); and allowance to use carbon monoxide as a VOC surrogate (20.2.50.113.C(4)(i)). Ms.

Bisbey-Kuehn credibly testified why these changes were made based on stakeholder feedback and technical testimony. Tr. 6:1694:8-25 - 6:1697:1-7. The Board should find these changes are supported by the record and unopposed.

Kinder Morgan: Kinder Morgan supports NMED's Section 113B Table 1.

GCA: The GCA supports NMED's proposed NOx emission standards for existing engines in Table 1. Owners and operators will face significant challenges to meet the proposed emission standards, particularly for some existing engines, but the proposed NOx emission standards for existing engines are largely technically feasible and economically reasonable for the majority of engines operated by GCA member companies. Tr. Vol. 6, 1756: 9-19 (Dutton). Selective catalytic reduction is not an economically reasonable control option for most existing engines. Low emissions combustion technology cannot be broadly retrofit to existing engines, and many existing engines already employ the available LEC technology and yet are not able to achieve the NOx emission standards included in the July 2021 draft of the proposed rule. GCA Ex. 12 (Dutton Direct) at 7-10; GCA Ex. 28 (Dutton Rebuttal) at 3-10. The proposed NOx emission standards are consistent with the NOx emissions standards in Pennsylvania general permit GP-5 limit for engines installed between 1997 and 2013. GCA Ex. 28 (Dutton Rebuttal) at 4; NMED Ex. 37 (Pennsylvania Permit GP-5) at 12. [For more of Mr. Dutton's testimony, see GCA's Closing Argument, pp. 3-6, proposed SOR 19-26.]

CEP and NPS would revise Table 1: CEP and NPS propose returning to the Department's proposal in its original Petition for Regulatory Change, which treats all engines or turbines "installed" after the effective date of the rule as "new" equipment subject to more stringent new-source standards. The Department's modified proposal is far too lax and will leave many cost-effective emission reductions on the table. Engines and turbines are by far the largest source of NOx emissions from the oil-and-gas industry. See 9 Tr. 2974:19–20 [Orozco Test.]; NMOGA Statement of Intent to Present Technical Testimony at 97 [Valor EPC Study: NMAC 20.2.50.113, Engines and Turbines]. Ozone formation in New Mexico is often NOx limited. Accordingly, reducing NOx from engines and turbines is an important strategy for reducing ozone levels in New Mexico. 9 Tr. 2974:21–23. Unfortunately, the Department's most recent proposal does far too little to reduce dangerous NOx pollution from engines. The regulations the Department proposed as part of its Petition for Regulatory Change would have reduced NOx emissions from engines by a total of 18,000 tons per year. However, the regulations included in the Environment Department's rebuttal testimony are expected to reduce NOx emissions by only 5,000 tons per year. 6 Tr. 1708:12–14 [Palmer Test.].

The Department estimates that the NOx controls for engines included in its rebuttal testimony will cost $11.4 million a year to implement, reducing 5,000 tons of NOx. See 6 Tr. 1678:6–8. This amounts to a cost of $2,280 per ton of NOx reduced. Emission controls that cost $7,500 a ton of NOx or less are generally deemed cost-effective. 6 Tr. 1703:19–1704:19 [Bisbey-Kuehn Test.]. In other words, the NMED's proposal inappropriately leaves cost-effective emission reductions "on the table." While the Department's original proposal might have faced strong industry opposition as overly stringent and costly, the Department overcorrected in its rebuttal, setting forth proposals that are far too lax, and will do too little reduce dangerous NOx pollution. Moderately increasing the stringency of the standards applicable to existing 4SLBs, as CEP and NPS propose to do, will partially correct for the Department's overcorrection and deliver additional emission reductions for New Mexico at reasonable cost.

As to the applicability of Table 1 and Table 2, CEP and NPS state that the regulations NMED proposed as part of its Petition would have treated newly "installed" engines as new sources subject to the most stringent emission limits. The rebuttal version deleted this proposal. See NMED Reb. Ex. 23 at 9. NMED did not provide an explanation why it deleted this proposal. See NMED Reb. Ex. 1 at 28.

The evidence indicates that, if operators can install old engines at new facilities in New Mexico without complying with new engine standards, New Mexico may become a dumping ground for old, high-pollution equipment that is no longer allowed in other states. 9 Tr. 2976:1–7. Notably, Colorado applies more stringent new source controls to engines that are "placed in service, modified, **or relocated**" after the effective date of its engines rule. 5 Colo. Code Regs. § 1001-9-E-I (Table 2) (emphasis added). New Mexico should do the same. See also CEP's proposed SOR 117-121.

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NEW NATURAL GAS-FIRED SPARK IGNITION ENGINES

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	> 500 and < 1875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ 1875	0.30 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

NMED: Paragraph (3) of Subsection B of Section 20.2.50.113 requires owners and operators of new spark ignited engines must meet the emission limits in Table 2 upon startup. Like Table 1, the Department proposed revised limits in Table 2 based on input from NMOGA, Kinder Morgan, and GCA. The rationale for the revised CO and NMNEHC limits for new engines in Table 2 is the same as that for the revised CO and NMNEHC limits in Table 1, and NMED is proposing the same CO and NMNEHC limits in Table 2 as in Table 1. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 37-56, and NMED Rebuttal Exhibit 1, pp. 34-35.

[Kinder Morgan and NMOGA's earlier proposal to increase the lower horsepower limits for new lean-burn and rich-burn engines in Table 2 from 500 hp to 1,000 hp is not in their final proposals.]

NMOGA: Ms. Kuehn testified that these limits were set based upon Ohio precedent and the compelling testimony of industry stakeholders. Kuehn/Palmer testimony, Tr. 6:1868:9-22. Mr. Lisowski testified extensively as to why the limits were appropriate; aA succinct summary is found in Lisowksi Rebuttal Testimony, NMOGA Exhibit 43. Mr. Brindley, Ms. Nolting and Mr. Trent also testified extensively in support of the final levels on behalf of Kinder Morgan. Tr. 6:1807:4-6:1814:8. Ms. Devore expressed some concern about the removal of "install" and whether this created enforceability issues, but upon further consideration agreed that the removal did not create a gap in the regulations. Tr. 8:2401:9-8:2402:2.

GCA: The GCA supports the NMED's proposed NOx emission standards for new engines in 20.2.50.113(B)(3), Table 2. The proposed NOx emissions standards and size categories for lean-burn engines are feasible and consistent with what is available on the market for companies seeking to purchase new engines. Tr. Vol. 6, 1749: 3-10 and 1749:20 to 1750:3 (Sheldon). The Department appropriately changed the NOx emission standards for new engines that were included in the July 2021 draft of the proposed rule, which would not be achievable for some families of new engines, despite the application of best available technology for reducing NOx emissions. Tr. Vol. 6, 1748: 7-17 (Sheldon). Selective catalytic reduction (SCR) is not an economically reasonable control option for most new engines, and is only economically viable for the largest engines that have specific site advantages, such as on-site electrical power and personnel. Tr. Vol. 6, 1753:15 to 1754:21 (Dutton). For those reasons, NMED appropriately raised the size threshold for the application of the most-stringent NOx emission standard from 1,000 horsepower to 1,875 horsepower in its proposal. Tr. Vol. 6, 1749:11-14 (Sheldon); Tr. Vol. 6, 1753:15 to 1754:6 (Dutton). [For more details about the testimony of Mr. Dutton and Mr. Sheldon, see GCA Closing Argument pp. 6-11 and proposed SOR 27-31.]

CEP and NPS propose more protective standards for existing 4SLBs:

CEP and NPS propose more protective standards for existing 4SLBs, a standard of 1.2 grams of NOx per horsepower hour for existing 4SLBs with a rated horsepower between 1,000 and 1,775, a standard consistent with that currently in effect in Colorado.

This proposal is substantially more protective than the standard NMED currently proposes for these engines (which, at 2.0 grams of NOx per horsepower hour, is 40% higher than the standard applicable to identical engines in Colorado), but not as stringent as the Department's original proposal of 0.5 grams of NOx per horsepower hour.

The weight of the evidence shows that a standard of 1.2 grams of NOx per horsepower hour is cost effective and achievable. The Colorado Air Pollution Control Division conducted a regulatory impact analysis for its 2019 rule and found the standard to be cost effective and achievable for all existing 4SLBs. The rule has been implemented there without difficulty. Other jurisdictions have implemented even stricter limits for these engines. For example, since 2007, Texas has required existing lean-burn engines in the Dallas-Fort Worth ozone nonattainment area to meet a standard of 0.7 grams of NOx per horsepower hour. See 30 Tex. Admin. Code § 117.2110(a)(1)(B)(i). In fact, since any lean-burn engine built since 2010 must already comply with a 1.0 grams of NOx per horsepower hour standard under federal law (40 C.F.R. § 60.4230, subpart JJJJ, Table 1) a significant number of existing engines are already complying with the standard proposed by the Community and Environmental Parties and NPS.

No party presented evidence why New Mexico operators could not achieve a relatively lax limit of 1.2 grams of NOx per horsepower hour at existing 4SLBs. NMOGA's analysis was focused on showing that the cost to bring emissions down to 0.5 gram of NOx per horsepower hour would be excessive. 9 Tr. 2978:13–17; see also NMOGA, Statement of Intent to Present Technical Testimony at 83–91.

Even if there were evidence showing that some existing 4SLBs cannot comply with a standard of 1.2 grams of NOx per horsepower hour at reasonable cost, this would not show that the proposal of Community and Environmental Parties and NPS is unachievable. That is because Section 113 contains numerous alternative compliance options in the event a particular engine cannot comply with the proposed standard at reasonable cost. NMOGA's expert Justin Lisowski acknowledged that the alternative compliance mechanisms included in the Environment Department's proposal could, if properly implemented, allay concerns about adopting a more stringent standard for existing 4SLBs. 9 Tr. 2995:8–24. <u>See also CEP's proposed SOR 97-116.</u>

<u>NPS on its two proposed changes, consistent with the changes proposed by CEP:</u>
In its Exhibit D (not reproduced here), NPS had earlier encouraged additional standards for smaller engines and turbines as well as stricter standards for larger engines, as comprehensive NOx reduction measures may be necessary to address ongoing ozone issues. However, NPS understands the scope of this rulemaking was limited to engines > 500 – 1,000 bhp and turbines ≥ 1,000 bhp depending on the application, and recognizes that this rulemaking proposes the first engine and turbine standards for these types of equipment in New Mexico. If the more stringent standards for smaller engines will not be considered at this time, NPS includes its final proposals in Exhibit F, below, with changes shown to the tables in Section 113B. CEP also urges the Board to adopt the

tables below as a replacement for NMED's proposed tables.

Table 1 - EMISSION STANDARDS FOR ~~EXISTING~~ NATURAL GAS-FIRED SPARK IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, AND INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
2 Stroke Lean Burn	>1,000	3.0 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	1.2~~2.0~~ g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
4-Stroke Lean Burn	≥1,775 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich Burn	>1,000 bhp	0.5 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

Table 2 - EMISSION STANDARDS FOR ~~NEW~~ NATURAL GAS-FIRED SPARK IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, AND INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	> 500 and < 1875	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥ 1875	0.30 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable ~~existing~~ natural gas-fired combustion turbine constructed, 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 the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,100	150	50	9
≥4,100 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each applicable ~~new~~ natural gas-fired combustion turbine constructed, reconstructed, and installed 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)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4,000	100	25	9
≥4,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

NPS: Ozone concentrations exceed the level of the ozone NAAQS at Carlsbad Caverns National Park--While regional ozone control strategies have successfully decreased ozone levels in many parts of the U.S., the Carlsbad, New Mexico area, including Carlsbad Caverns National Park (CAVE), has been struggling with degrading air quality. The current NAAQS value for ozone is 70 parts per billion (ppb); the ozone design value is the annual 8-hr, 4th highest ozone value, averaged over 3-years. As shown in Table 1 for CAVE, which provides the year, number of exceedance days, ozone design value years, and the ozone design value for the corresponding 3-year period, the park has transitioned from having no ozone exceedance days to regularly exceeding the NAAQS. In addition, the larger Carlsbad, New Mexico area is on pace to being designated an ozone nonattainment area by the EPA.

Table 1: Monitored Ozone Concentrations at CAVE (2014-2021)

Year	# Exceedance Days	Years	8-hr 4th High Ozone (ppb)	NAAQS (ppb)
2016	None	2014-2016	67	70
2017	None	2015-2017	66	70
2018	10	2016-2018	71	70
2019	6	2017-2019	74	70
2020	9	2018-2020	73	70
2021	15	2019-2021	74	70

Modeling demonstrates oil and gas emissions are significant for ozone in New Mexico. From the Department's Exhibit 23, modeling demonstrates that ozone design values have been increasing in Southern New Mexico since 2012 – 2016. If current design value concentrations are defined using 2017 – 2019 data, future year (2028) design values are predicted to exceed the 2015 ozone NAAQS in Carlsbad without additional oil and gas emissions reductions. Additionally, modeling shows that oil and gas emissions have a significant contribution to ozone both in terms of the future design value averages and episodic maximums. For comparison, in the EPA Cross-State Air Pollution rulemaking process, a threshold equal to 1% of the ozone NAAQS (under 1 ppb) was used when determining whether a state significantly contributes to downwind ozone in a neighboring state. Oil and gas emissions are also found in the modeling to be a significant portion of New Mexico's contribution to ozone.

Carlsbad Caverns stands out as being heavily affected by oil and gas sources of all studied national parks for ozone formation. A VOC survey study conducted at CAVE in 2017 demonstrated large-scale contributions of VOCs from oil and gas emissions at the park and regionally. While no ozone exceedances were measured at CAVE from 2013-2017, there were 10 ozone exceedance events in 2018, demonstrating the impact of increased oil and gas operations in the region. Additionally, this gave rise to concerns of elevated aerosol concentrations in the region that can affect human health and impair visibility. A second intensive air quality study was conducted at CAVE to better understand the factors driving both ozone and aerosol particle concentrations at the park. This 6-week study was conducted at CAVE by the NPS from July 24-September 3, 2019. The study included a comprehensive suite of gaseous and particulate measurements to provide a detailed characterization of pollutants and to aid in quantifying the air quality impacts from regional oil and gas operations. In addition to the comprehensive suite of instruments deployed at the park, whole air samples were collected throughout the region to provide information on the spatial distribution of VOCs.

It is well documented that oil and gas operations emit a wide range of VOCs and oxides of nitrogen (NOx). In particular, elevated levels of light alkanes (C2-C5) are indicative of oil and gas emissions. Light alkanes measured at the park and throughout the region demonstrated conclusively that emissions from oil and gas operations in the Permian Basin are impacting CAVE, a Class I area afforded the highest level of air quality protection. During both the 2017 and 2019 studies at CAVE, light alkanes were the most abundant VOCs as has been observed in other oil and gas basins across the U.S. For CAVE, light alkane levels were elevated, on average, by approximately an order of magnitude above summertime regional background values. During pollution events at the park, it was not uncommon to see alkane levels that were more than two orders of magnitude over regional background levels, illustrating the persistence and magnitude of the impact of oil and gas emissions at CAVE. Additionally, alkyl nitrates, which can be used to estimate the "age" of air masses, provided insight regarding whether the emission sources impacting the park were local (young) or were transported from more distant sources outside of the region (old). For CAVE, the air mass ages were typically young, particularly during episodic pollution events, indicating that the emissions were from local sources. In addition, the mix of total nitrogen compounds (NOy to NOx) can also provide insight on emission source origins. In CAVE, the mix of total nitrogen compounds clearly indicates nearby sources of NOx as the dominant contributor to ozone formation. Monitoring information shows increasing NOx concentrations in the region along with upward trends in ozone. Current information indicates that NOx emission reductions will be necessary to curb ozone production.

Correlations between the types of VOC compounds were used to identify both the magnitude and persistence of oil and gas operation emission influences on CAVE's air quality. For example, all alkanes were highly correlated with oil and gas emissions, indicating that oil and gas operations were the major contributor to VOC levels in the atmosphere. Also, the ratio of iso-pentane to n-pentane can be used to fingerprint VOC emission sources. This ratio typically ranges from roughly 2 to 4 for fuel evaporation, and combustion emissions throughout the U.S. A ratio of less than one indicates an area is influenced by oil and gas operations. For CAVE, these values were about 0.85 in 2017 and 0.83 in 2019, conclusively demonstrating that oil and gas operations are impacting air quality at the park and in the region.

The combined effect of increased NOx and VOC levels, and the corresponding increasing ozone levels throughout the region (Table 1) illustrate that oil and gas operations are significantly impacting the air quality at CAVE. To mitigate the effects of these emissions and their ultimate impacts on both human health and natural resources, a combined strategy of reducing both NOx and VOC emissions is necessary.

The NPS reviewed engine and turbine limits included in state rules across the country. Based on this review, we suggest that slightly more stringent standards and revised definitions are feasible for engines and turbines. These standards are a necessary starting point given the NOx contribution of these sources and the contribution of oil and gas emissions to air quality issues in New Mexico.

Initially, the NPS proposed limits similar to those currently required by Pennsylvania as part of their general permit program for oil and gas sources except for the proposed limit for existing large (>60,000 bhp) turbines. These limits are in Pennsylvania's proposed RACT III requirements. The 4-stroke lean-burn engine NOx standards currently proposed at 2.0 g per bhp-hr should be changed to 1.2 g per bhp-hr in Table 1, shown in NPS Exhibit F. This is based on Colorado's recent engine rulemaking for the similar engines and size that is presented as NMED Exhibit 39.

IPANM opposes the NPS/CEP revisions: NPS proposed that lower NOx engine emission limits should be adopted based on regulations adopted in Pennsylvania. NPS, Summary of Technical Testimony to New Mexico Regarding the Proposed Ozone Precursor Rule, 2; IPANM Ex. 12 at 17 (Blewitt Rebuttal). IPANM contracted with Spirit Environmental to review the feasibility of the emission limits proposed by NPS. IPANM Ex. 12 at 17 (Blewitt Rebuttal), IPANM Ex. 13 (Spirit Environmental Report). The report demonstrates that the emission limits proposed by NPS cannot be achieved on a continuous basis. IPANM Ex. 13 at 25 (Blewitt Rebuttal). NMOGA also testified that the emission limits in the proposed rule are difficult to attain. NMOGA A1 at 7 (Smitherman Direct). The proposed NOx emission rates in some horsepower ranges result in a single provider situation that can cause a monopoly. Id. Kinder Morgan testified that this section of the proposed rule has the potential for greatest impact on Kinder Morgan's operations, particularly with the expense related to meeting the emission limitations. KM Ex. VI at 1 (Brindley Direct, Trent Direct). The GCA expressed concern that some of these emission limits are inconsistent with available technology to retrofit existing engines. GCA Ex. 12 at 4 (Dutton Direct). The GCA was also concerned with the requirement to have the owner or operator of a compressor engine follow a manufacturer-recommended maintenance plan rather than an expert operator-tailored, time-tested and "conditions-based" maintenance plan for which GCA currently operates with. GCA Ex. 15 at 4 (Copeland Direct). Specifically, GCA highlighted how highly incentivized a compression package operator is to properly maintain their "expensive, revenue-generating equipment" and that a generic requirement for maintenance was inappropriate given the incentives already at play. GCA Ex. 15 at 5 (Copeland Direct).

CDG testified as to the potential confusion between the more frequent testing required by NMED as opposed to the federal rules. CDG Ex. B at 3 (Campsie Direct). CDG suggests that the testing of engines be changed to mirror 40 C.F.R. Part 60, Subpart JJJJ. Id. In its rebuttal testimony, CDG supported NMOGA's changes to lean burn emission factors and highlighted that some existing engines would be unable to meet the emission limits proposed by NMED. CDG Rebuttal Ex. B at 3 (Campsie Rebuttal).

NMED testified to its bases for their cost estimates versus emissions reductions. NMED also explained there was a shorter compliance timeline for turbines as opposed to engines because there are fewer of them that would be subject to the proposed rule. NMED addressed some concerns about compliance of engines that are unable to meet emission standards with the proposed rule by allowing for an Alternative Compliance Plan. The plan would allow operators to determine equivalent amounts of reductions using alternative strategies. NMOGA provided an overview of the process associated with emission control technologies. Tr. Vol. 6, 1724:6-1735:17 (Lisowski). NMOGA further testified that CO limits should be removed because CO is not a precursor to ozone. The rule should be rewritten to mirror NSPS JJJJ. Tr. Vol. 6, 1737:15-24 (Lisowski). The GCA testified that changes NMED had made to the rule satisfied some of the GCA concerns regarding the emission standards for engines. Tr. Vol. 6, 1749:20-1750:3 (Sheldon). GCA highlighted that even with the changes to the rule, there will still be significant challenges to meet the requirements. Tr. Vol. 6, 1756:9-22 (Dutton). Finally, GCA testified in support of NMED's decision not to include the NPS's requested changes based on the Pennsylvania GP-5 permit. Tr. Vol. 6, 1760:7-13 (Dutton). Kinder Morgan also provided an overview of compressor engines. Tr. Vol. 6, 1806:12-1807:18 (Brindley). Kinder Morgan supported many of the Department's changes, but explained that all the retrofits would be a significant cost. Tr. Vol. 6, 1813:23-1814:8 (Trent). CDG reiterated its testimony that this rule mirror NSPS JJJJ for consistency. Tr. Vol. 6, 1841:3-20 (Campsie).

NPS requested that New Mexico watch Colorado to see how their rulemaking will be addressed. This is a change in NPS's position that smaller engines do not need to be addressed in this proceeding. Tr. Vol. 8, 2395:2-6 (Devore); Tr. Vol. 8, 2400:4-9 (Devore). NPS also asserts that there needs to be a limit on CO so operators are applying their controls properly. Tr. Vol. 8, 2397:4-9 (Devore). CAA testified that the proposed rule, as revised, is flexible and allows operators to continue using engines that do not meet the Department's emission standards. Tr. Vol. 9, 2979:7-15 (Orozco). CAA testified that this is inappropriate because operators will not be required to implement cost-effective controls at all of their engines. Tr. Vol. 9, 2979:16-21 (Orozco).

Based on the evidence presented, the Board should find that the emission limits in Section 113 of NMED's draft rule for engines and turbines are appropriate. [For more details, see IPANM's proposed SOR 147-173.]

Kinder Morgan opposes the NPS/CEP revisions: NPS's proposals were based at least in part on the regulatory requirements of other states, including Colorado and Pennsylvania. The Department's rejection of the proposals reflects, however, that the regulatory programs of those states include exemptions or apply narrowly to certain categories of regulated units such that blanketly adopting the requirements in New Mexico would not be advisable. See Hearing Transcript, Vol. 6, 1701:12–1702:5.

NPS's proposals would also result in unreasonably high costs of compliance. We reiterate the cost-effectiveness analyses related to the Department's originally-proposed NOx limits for certain of Kinder Morgan's existing units that will be subject to the Proposed Rules that we provided in the Direct NOI, Exhibit VI, at pages 2–6:

- Rio Vista Transmission Compressor Station: Two 1,051 HP turbines, originally subject to 50 ppmvd NOx standard. Costs to control:
  - ~$974,508 per ton of NOx reduced for one unit
  - ~$830,527 per ton of NOx reduced for the other unit
- Caprock Transmission Compressor Station: Two 5,000-7,000 HP turbines; originally subject to 50 ppmvd NOx standard. Costs to control:
  - ~$80,398 per ton of NOx reduced for one unit
  - ~$54,935 per ton of NOx reduced for the other unit
- Monument Transmission Compressor Station: Two, two-stroke lean-burn engines of approximately 1,000 HP; originally subject to 0.50 g/bhp-hr NOx standard. Costs to control:
  - ~$72,527 per ton of NOx reduced for one unit
  - ~$125,428 per ton of NOx reduced for the other unit
- Washington Ranch Transmission Compressor Station: Two, two-stroke lean-burn engines of approximately 4,500 HP; originally subject to 0.50 g/bhp-hr NOx standard. Costs to control:
  - ~$10,392 per ton of NOx reduced for one unit

- o ~$30,395 per ton of NOx reduced for the other unit

Because NPS proposed even lower NOx limits for existing turbines than the Department originally proposed, its proposal would only further exacerbate the cost concerns for the Kinder Morgan's units at Rio Vista and Caprock. NPS also recommended maintaining the originally-proposed standard applicable to the engines at Monument and Washington Ranch. As demonstrated above, that standard would result in unreasonably high control costs.

We also reiterate our testimony regarding the Department's originally-proposed 25 ppmvd NOx standard for the smallest category of new turbines under the Proposed Rules. See Direct NOI, Ex. VI, at 10 (explaining that there is no manufacturer that sells turbines in the 1,000–3,999 bhp range that meet 25 ppmvd of NOx); Rebuttal NOI, Ex. XIII, at 1–2 (same). Because new turbines of this size do not meet the 25 ppmvd standard, meeting the standard would require the installation of SCR, which is extremely expensive. Direct NOI, Ex. VI, at 10–11 (explaining that installing SCR on the existing turbine units at Rio Vista would cost close to $1 million per ton of NOx reduced, and that similar if not higher costs would be expected for new units). Accordingly, NPS's proposal to maintain the originally-proposed 25 ppmvd NOx standard for new turbines ≥ 1,000 and < 5,000 turbines is unworkable.

Kinder Morgan supports the Department's rejection of NPS's proposals and respectfully requests that the Board adopt the Department's proposed Tables 1, 2, and 3 for engines and turbines as reflected in the January 18 Draft.

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission 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 fifteen percent oxygen.

<u>NMED:</u> Paragraph (4) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

NMED: Paragraph (5) of Subsection B of Section 20.2.50.113 sets emissions standards for compression ignition engines. The proposed NOx emission limit for new compression ignition engines equal to or greater than 500 hp of 9 g/bhp-hr is the same limit as Colorado Reg. 7 Part E, Section II.A.4.e. The emission limit is based on the use of add-on SCR controls. The proposed rule does not include proposed emission limits for existing compression ignition engines. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 43.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission 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 fifteen percent oxygen.

NMED: Paragraph (6) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to Part 50 by July 1, 2023, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC as follows, except as otherwise specified under an Alternative Compliance Plan approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC or alternative emissions standards approved pursuant to Paragraph (11) of Subsection B of 20.2.50.113 NMAC:

(i) by January 1, 2024, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2026, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meet the emission standards.

(iii) by January 1, 2028, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meet the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE of NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, or by at least ninety-five percent per year.

NMED: Paragraph (7) of Subsection B of Section 20.2.50.113 requires owners and operators of new and existing stationary with rated bhp greater than or equal to 1,000 bhp to meet the NOx and CO emission limits specified in Table 3 by certain dates unless otherwise specified under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. Owners and operators of existing stationary natural gas-fired combustion turbines are required to develop an inventory of those turbines and meet the emission limits in Table 3 over a specified timeline, unless otherwise provided under an alternative compliance plan or alternative emissions standards approved pursuant to this Section. This timeline requires a certain percentage of the inventoried fleet to meet the requirements by specified deadlines. The Board should adopt this proposal because the staggered timeline allows owners and operators sufficient time to come into compliance with the requirements of this Section. Further, in lieu of meeting the emissions limits, owners and operators may reduce the number of hours of operation in order to reduce emissions to rates similar to the emissions reduction requirements achieved by utilizing emission control devices. The Board should adopt this proposal because it provides flexibility by allowing an alternative method of compliance for turbines that are difficult to retrofit, while ensuring equivalent emission reductions. *See* NMED Exhibit 32, p. 36; NMED Rebuttal Exhibit 1, pp. 36-37.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable existing natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:			
Turbine Rating (bhp)	**NO_x (ppmvd @15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane, ppmvd @15% O_2)**
≥1,000 and <4,100	**150**	**50**	**9**
≥4,100 and <15,000	**50**	**50**	**9**
≥15,000	**50**	**50 or 93% reduction**	**5 or 50% reduction**
For each applicable new natural gas-fired combustion turbine, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	**NO_x (ppmvd @15% O_2)**	**CO (ppmvd @ 15% O_2)**	**NMNEHC (as propane, ppmvd @15% O_2)**
≥1,000 and <4,000	**100**	**25**	**9**
≥4,000 and <15,900	**15**	**10**	**9**
≥15,900	**9.0 Uncontrolled or 2.0 with Control**	**10 Uncontrolled or 1.8 with Control**	**5**

NMED: Table 3 of Paragraph (7) sets forth the emission limits for new and existing stationary combustion turbines. The emission limits and applicability thresholds originally proposed by the Department and the basis for those limits are set forth in the pre-filed direct testimony of Elizabeth Bisbey-Kuehn and Brian Palmer, and were based on the PA TSD 2018 (NMED Exhibit 52), except that the proposed NOx limits for existing turbines were based on EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) ("EPA 1993 ACT") (NMED Exhibit 53). *See* NMED Exhibit 32, at pages 43-46. The Department has proposed revised emissions limits in Table 3 based on information submitted by NMOGA, Kinder Morgan, and Solar Turbines. *See* NMED Rebuttal Exhibit 2, pp. 37-39.

The revised emission limits for NOx in Table 3 for existing turbines equal to or greater than 1,000 hp and less than 4,100 hp (150 ppmvd at 15% O2) is the same as that recommended by Solar Turbines, and is the similar to the limit in Colorado's Reg. 7 for existing turbines firing natural gas and less than or equal to 50 MMBtu/hr. *See* Tr. Vol. 6, 1689:4-21. The NOx limit for new or reconstructed turbines (100 ppmvd at 15% O2) is similar to the limit for reconstructed turbines in the federal NSPS regulations at 40 C.F.R. 60, Subpart KKKK. NMED is also proposing to accept Solar Turbine's recommendation to change the upper end of the horsepower cutoff for turbines subject to the 150 ppmvd NOx limit from 5,000 bhp to 4,100 bhp because it would place Solar's Saturn and Centaur 40 4000 turbines, for which Solar reports there is no dry low NOx option, in the small category and the Centaur 40 turbines (with 4,500 bhp and 4,700 bhp ratings) in the middle category for which Solar Turbines reports there is a dry low NOx retrofit option available. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 43-46, and NMED Rebuttal Exhibit 1, p. 39.

[NMOGA and Kinder Morgan's earlier proposal to delete the CO emission standards for turbines is not part of their final proposals.]

NMOGA supports: As to Table 3, Ms. Kuehn testified that these limits were derived based on research and comments from manufacturers. Kuehn/Palmer testimony, Tr. 6:1689:4-6:1690:3. Ms. Witherspoon, representing Solar Turbines, testified that the Department's September 16, 2021, table, if corrected to 4,100 bhp for existing turbines, was appropriate and achievable. Tr. 10:3374:6-25.

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission 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 fifteen percent oxygen.

NMED: Paragraph (8) of Subsection B of Section 20.2.50.113 addresses emissions of unreacted ammonia from SCR systems. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 33-34.

(9) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

NMED: Paragraph (9) of Subsection B addresses emergency use engines as defined by federal law, and imposes a requirement to record hours of operation of such equipment.

This requirement is not related to emissions and therefore is not preempted by the CAA. No party objected to the inclusion of this language. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 39.

Kinder Morgan: regarding **113.B(9), C(6), and D(3):** Kinder Morgan, along with other parties, has supported NMED's proposal in each draft of the Proposed Rules to exempt emergency engines from 20.2.50.113 NMAC. Kinder Morgan provided comment and proposed revisions intended to resolve concerns of conflict between the state's use of the term "emergency engine" and the federal definition of "emergency engine." NMED has since adopted Kinder Morgan's revisions. We request the Board adopt these provisions, as drafted, to avoid unintended conflict with federal programs under the Clean Air Act. [For additional detail, see Kinder Morgan's Closing Argument pp. 15-16.]

(10) In lieu of complying with the emission standards for individual engines and turbines established in Subsection B of 20.2.50.113 NMAC, an owner or operator may elect to comply with the emission standards through an Alternative Compliance Plan (ACP) approved by the department. An ACP must include the list of engines or turbines subject to the ACP, and a demonstration that the total allowable emissions for the engines or turbines subject to the ACP will not exceed the total allowable emissions under the emission standards of this Part. Prior to submitting a proposed ACP to the Department, the owner or operator shall comply with the following requirements in the order listed:

(a) The owner or operator shall contract with an independent third-party engineering or consulting firm to conduct a technical and regulatory review of the ACP proposal. The selected firm shall review the proposal to determine if it meets the requirements of this Part, and shall prepare and certify an evaluation of the proposed ACP indicting whether the ACP proposal adheres to the requirements of this Part.

(b) Following the independent third-party review, the owner or operator shall provide the ACP, along with the third-party evaluation and findings, to the department for posting on the department's website. The department shall post the ACP and the third-party review within 15 days of receipt.

(c) Following posting by the department, the owner or operator shall publish a notice in a newspaper of general circulation announcing the ACP proposal, the dates it will be available for review and comment by the public, and information on how and where to submit comments. The dates specified in the public notice must provide for a thirty-day comment period.

(d) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the ACP proposal and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(e) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the ACP proposal within 90 days. The department shall approve an ACP that meets the requirements of this Part, unless the department determines that the total allowable emissions under the ACP exceed the total allowable emissions under the emission standards of 20.2.50.113 NMAC. If approved by the department, the emission reductions and associated emission limits for the affected engines or turbines shall become enforceable terms under this Part.

NMED: Paragraph (10) of Subsection B of Section 20.2.50.113 authorizes an owner or operator to comply with the emissions standards of this Section through an alternative compliance plan or "ACP". This proposal was included at the request of NMOGA and Kinder Morgan, and would provide an alternative to requiring individual sources to meet the emission standards in Part 50. Owners and operators would instead be able to reduce emissions across the entire company fleet, which provides flexibility in the manner in which owners and operators can achieve an equivalent amount of emission reductions in accordance with the same compliance deadlines.

NMED proposes revisions to the industry proposal, including two additional requirements that are critical for making the ACP concept workable for the Department. First, owners and operators are required to have the ACP reviewed by an independent third-party consulting or engineering firm, which will certify the integrity of the proposal and ensure that the emissions reductions as represented in the proposed ACP are equivalent to reductions achieved by the emissions standards in the rule. Transferring the initial technical review to an outside independent firm will help to alleviate some of the additional burdens on the Department's already constrained resources that will arise from allowing ACPs as means to comply with Part 50. Second, an owner or operator must post the draft ACP for public comment for 30 days and provide notice to the public by publishing a newspaper notice in a newspaper of general circulation. The owner or operator will be required to provide responses to any public comments received to the Department for the Department's consideration in reviewing the ACP. This process will ensure transparency and will provide additional confidence to the Department and the public that a proposed ACP will in fact result in equivalent reductions as would be achieved by the compliance with the emissions standards in the rule. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Exhibit 1, pp. 39-40.

(11) The owner or operator may submit a request for alternative emission standards for a specific engine or turbine based on technical impracticability or economic infeasibility. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B of 20.2.50.113 NMAC prior to submission of a request for alternative emissions standards under this Paragraph (11), provided that the owner or operator satisfies Subparagraph (b) of Paragraph (11) of Subsection B of 20.2.50.113 NMAC, below. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:

(a) Prepare a reasonable demonstration detailing why it is not technically practicable or economically feasible for the individual engine or turbine to achieve the emissions standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC or table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC, as applicable;

(b) Prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner;

(c) Prepare a technical analysis for the affected engine or turbine specifying the emission reductions that can be achieved through other means, such as combustion modifications or capacity limitations. The technical analysis shall include an analysis of any previous modifications of the source and a determination whether such modifications meet the definition of a reconstructed source, such that the source should be considered a new source under federal regulations. The analysis shall include a certification that the modifications to the source are not in violation of any state or federal air quality regulation; and

(d) Fulfill the requirements of Subparagraphs (a) through (c) of Paragraph (10) of Subsection B of 20.2.50.113 NMAC.

(e) Following the close of the thirty-day notice and comment period, the department shall send the comments submitted on the alternative emission standards and findings to the owner or operator. The owner or operator shall provide written responses to all comments to the department.

(f) Following receipt of the owner or operator's responses to comments received during the thirty-day comment period, the department shall make a determination whether to approve or deny the alternative emission standards within 90 days. If approved by the department, the emission reductions and alternative emission standards for the affected engine or turbine shall become enforceable terms under this Part.

(g) If approved by the department, the emissions reductions and alternative standards for the affected engine or turbine shall become enforceable terms under this Part.

NMED: Paragraph (11) of Subsection B of Section 20.2.50.113 allows an owner or operator to request an alternative emission standard for individual engines and turbines that cannot meet equivalent emission reductions under an ACP. This proposal was also included at the request of NMOGA and Kinder Morgan. A request for an alternative emission standard must follow the same process as an ACP. First, owners and operators are required to have the proposed alternative emission standard reviewed by an independent third-party consulting or engineering firm, which will certify the integrity of the proposal and ensure that the emissions standards as represented in the proposal are appropriate for the source. Transferring the initial technical review to an outside independent firm will help to alleviate some of the additional burdens on the Department's already constrained resources that will arise from allowing alternative emission standards as means to comply with Part 50. Second, an owner or operator must post the draft alternative emission standard for public comment for 30 days and provide notice to the public by publishing a newspaper notice in a newspaper of general circulation. The owner or operator will be required to provide responses to any public comments received to the Department for the Department's consideration in reviewing the proposed alternative emission standard. This process will ensure transparency and will provide additional confidence to the Department and the public that a proposed alternative emission standard will in fact result in an accurate proposal with appropriate reductions from the source. An owner or operator seeking an alternative emission standard for an individual engine or turbine must also demonstrate through an analysis of all past modifications to the unit that the unit has not in fact been modified to the extent that the unit should be considered reconstructed under the Clean Air Act and, therefore, subject to federal standards of performance or other requirements. The analysis must include a certification that the modifications to the source are not in violation of any state or federal air quality regulation. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Exhibit 1, pp. 40-41.

NMOGA and Kinder Morgan had earlier proposed provisions that would allow owners and operators to submit a justification of the technical impracticability or economic infeasibility of requiring certain turbines to comply with the emission standards of Part 50. Their proposal included requirements for when the Department would be required to review and approve the exemption, and an automatic approval if the Department failed to act within certain timelines. The Department's proposed language in Paragraph (11) allows the Department to consider individual technical infeasibility demonstrations where certain prerequisites are met, including a demonstration that the emissions of a particular source cannot be addressed through an ACP. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Exhibit 1, p. 36.

NMOGA and Kinder Morgan had also earlier proposed revisions allowing for additional time to comply with the emission standards if good cause is shown. The current proposal already offers significant flexibility for sources that are unable to meet the emission standards of Part 50: they may reduce the annual hours of operation, they may seek an Alternative Compliance Plan to meet an equivalent amount of emission reductions, and/or they may seek alternative emissions standards if they can demonstrate that they cannot meet the existing standards through an ACP. The current compliance timelines proposed by the Department are sufficient. The staggered compliance timeline extends through 2028, giving owners and operators nearly seven years to fully comply with the emission standards. See NMED Rebuttal Exhibit 1, pp. 36-37.

<u>Kinder Morgan:</u> Regarding **113.B(10) and (11):** Kinder Morgan supports the two options for alternative compliance with the engines and turbines emissions standards: (i) the alternative compliance plan in Paragraph (10) of Subsection B of 20.2.50.113 NMAC, and (ii) the alternative emissions standard in Paragraph (11) of Subsection B of 20.2.50.113 NMAC. Without these two alternative compliance options, the emissions standards would be technically infeasible and/or cost-prohibitive in many cases. While the emissions thresholds provided in Tables 1 and 3 for existing engines and turbines are appropriate in most cases, circumstances may exist where it is technically impracticable or economically infeasible to achieve compliance.

Paragraphs (10) and (11) of Subsection B of 20.2.50.113 NMAC allow an operator to present evidence that an alternative compliance option is necessary and appropriate. The owner or operator is not required to submit an ACP proposal under Paragraph (10) of Subsection B prior to submission of a request for an alternative emissions standard under Paragraph (11). It is, however, the expectation that an operator demonstrate why emissions from the individual engine or turbine cannot be addressed through an ACP in a technically practicable or economically feasible manner. Cost-effectiveness thresholds above which a certain control technology will be considered infeasible can vary, but, in general, the Department considers costs in excess of $7,500 per ton of pollutant reduced to be infeasible. Each technical analysis must include, among other items, a determination of whether any previous modifications of the source cause (or caused) that source to be categorized as a "new" source. Operators should expect to rely on EPA guidance to determine whether a modification has occurred under federal law. [For more details, see Kinder Morgan's Closing Argument, pp. 19-22.]

(12) A short-term replacement engine may be substituted for any engine subject to Section 20.2.50.113 NMAC consistent with any applicable air quality permit containing allowances for short term replacement engines, including but not limited to New Source Review and General Construction Permits issued under 20.2.72 NMAC. A short-term replacement engine is not considered a "new" engine for purposes of this Part unless the engine it replaces is a "new" engine within the meaning of this Part. The reinstallation of the existing engine following removal of the short-term replacement engine is not considered a "new" engine under this Part unless the engine was "new" prior to the temporary replacement.

<u>NMED:</u> Paragraph (12) of Subsection B allows for the use of short-term replacement engines, as authorized under the Board's regulations for new source review and general construction permits at 20.2.72 NMAC. The Department added this paragraph at the request of NMOGA. The Board should adopt this proposal because it addresses the need for owners and operators to replace engines on a short-term basis, and align with the authorizations of the permits. *See* NMED Rebuttal Exhibit 1, p. 41.

<u>NMOGA:</u> While the Department's initial petition imposed unworkable emissions limits on engines and turbines, the Department has now proposed standards that are both aggressive and achievable. The Department has also incorporated several crucial changes that eliminate unenforceable standards, provide flexibility, and ensure environmental protection. These include the exclusion of nonroad engines (20.2.50.113.A), the redefining of construction to exclude relocation and like-kind replacement (20.2.50.7.J), extended implementation timelines (20.2.50.113.B.2 and B.7(a)), an alternative compliance plan option (20.2.50.113.B(10)), an alternative emission standard allowance in cases of technical impracticability or economic infeasibility (20.2.50.113.B(11)), and the incorporation of the short-term replacement engine substitution concept currently authorized in many air quality permits (20.2.50.113.B(12). To ensure engine and turbine

standards maintain “technical practicability and economic reasonableness,” the Board should finalize the tables and concepts as presented in NMED’s and NMOGA’s redlines.

C. Monitoring requirements:

(1) Maintenance and repair for a spark ignition engine, compression ignition engine, and stationary combustion turbine shall meet the manufacturer recommended maintenance schedule as defined in 20.2.50.112 NMAC.

(2) Maintenance conducted consistent with an applicable NSPS or NESHAP requirement shall be deemed to be in compliance with 20.2.50.113.C(1) NMAC.

(3) Catalytic converters (oxidative, selective, and non-selective) and AFR controllers shall be inspected and maintained according to manufacturer specifications as defined in 20.2.50.112 NMAC, and shall include replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(4) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated within 180 days of the effective date applicable to the source as defined by Subsection B(2) and (7) or, if installed more than 180 days after the effective date, within 60 days after achieving the maximum production rate at which the source will be operated, but not later than 180 days after initial startup of such source. Compliance with the applicable emission standards shall be demonstrated by performing an initial emission test for NOx and VOC, as defined in 40 CFR 51.100(s) using U.S. EPA reference methods or ASTM D6348. Periodic monitoring shall be conducted annually to demonstrate compliance with the allowable emission standards and may be demonstrated utilizing a portable analyzer or EPA reference methods. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

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

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

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

If the manufacturer’s rated BSFC is not available, an operator may use an alternative load calculation methodology based on available data.

(a) emissions testing shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be

conducted in accordance with the requirements of the current version of ASTM D6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(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 U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. 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 before 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 U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

[NMED's basis for all of Section C below.]

CDG proposes changes:

(4)(h) "emissions testing shall be conducted at least once per calendar year every 8760 hours of operation or 3 years, whichever comes first. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC. and is completed at least once per calendar year."

(5) "The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours or every 3 years of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC."

CDG: These revisions are proposed to be consistent with federal regulations and avoid conflicting requirements between the Proposed Rule and federal regulations. CDG NOI

Direct Testimony: Ashley Campsie pgs. 3-4; CDG NOI Rebuttal Testimony: Ashley Campsie pgs. 3-4.

NMOGA proposes a change in paragraph (4)(h):

(4)(h) "emissions testing shall be conducted at least once per 8760 hours of operation or three calendar years, whichever comes first."

NMOGA: The CDG requested a change to 8760 hours or 3 years. NMOGA agrees with this change for non-emergency engines but not for emergency engines, which by definition should have fewer than 300 hours of operation in three years. Emergency engines should be left at 8760 hours.

(i) The results of emissions testing demonstrating compliance with the emission standard for CO may be used as a surrogate to demonstrate compliance with the emission standard for NMNEHC.

(5) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (4) of Subsection C of 20.2.50.113 NMAC.

(6) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall monitor the hours of operation by a non-resettable hour meter.

(7) An owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(8) Prior to any monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 and 113 NMAC.

NMED: Subsection C of 20.2.50.113 sets forth monitoring requirements for owners and operators of new and existing engines and turbines. These requirements were revised from NMED's original proposal based on comments submitted by NMOGA and Kinder Morgan. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 36-37; NMED Rebuttal Exhibit 1, pp. 41-43; and Tr. Vol. 6, 1693:22 – 1697:7.

CDG proposes revisions to Paragraph (4)(h) and (5) of Subsection C that would require emission testing every 8760 hours or 3 years, whichever comes first, to be consistent with NSPS JJJJ. NMOGA agrees with that proposal as to non-emergency engines. NMED did not agree with this relaxation of emissions testing requirements for engines and turbines. The Board should reject this proposal because the requirement to conduct an annual emissions test is reasonable, is necessary to demonstrate compliance with the emissions standards of this section, and is in accordance with the Department's protocol for engine testing for regular construction permits. NMED Rebuttal Ex. 1A, p.1.

GCA: The GCA supports the NMED's proposed engine maintenance schedule requirement in 20.2.50.113(C)(1). The NMED's cross-reference to "manufacturer recommended maintenance schedule" as defined in 20.2.50.112 allows for the use of a maintenance schedule that is sufficient to operate and maintain engines in good working order and that has been approved by qualified maintenance personnel based on engineering principles and field expertise. The proposed rule recognizes that an engine manufacturer's minimum recommended maintenance schedule is a one-size-fits-all recommendation that does not account for the actual service and operating conditions of a particular engine, and that engine operators are the true experts in developing and implementing an appropriate maintenance schedule. GCA Exhibit 15 (Copeland Direct) at 3-6. In addition, the cross-reference (along with 20.2.50.113(C)(2)) make the proposed rule consistent with the applicable federal air rules that govern engines, which allow for maintenance and inspection schedules that have been tailored to a particular engine's service and operation, consistent with good air pollution control practice for minimizing emissions. GCA Exhibit 15 (Copeland Direct) at 6-7.

The GCA also supports the NMED's proposed catalytic converter inspection and maintenance schedule requirement in 20.2.50.113(C)(3). Catalytic converters used to control engine emissions should not be subject to a monthly inspection requirement, because monthly physical inspections of catalytic converters are unnecessary to ensure continued performance of the catalytic converters and potentially have long-term negative impacts on the catalyst that is used to control emissions. GCA Exhibit 23 (Filby Direct) at 5. NMED's clarification that the requirement for monthly inspections of all control devices required by 20.2.50.115(B)(3) in the proposed rule's general control device provisions is a visual inspection to identify leaks and releases addressed the GCA's concerns regarding the rule's inspection requirements for catalytic converters. Tr.

Vol. 6, 1900:13-1901:12 (Filby).

The GCA also supports the NMED's proposal in 20.2.50.113(C)(4)(i) to allow the results of emissions testing demonstrating compliance with the emission standard for CO to be a surrogate to demonstrate compliance with the emission standard for NMNEHC. For purpose of engine emissions testing, CO serves as a reliable surrogate for NMNEHC, and the New Mexico Air Quality Bureau's permit template language allows permit holders to use engine emissions test results for CO to demonstrate compliance with permit emissions standards for NMNEHC. GCA Ex. 25 (Bartley Direct) at 3-6; Tr. Vol. 6, 1797:12-1798:16 (Bartley). [For additional detail in the testimony of Mr. Copeland, Mr. Filby, and Mr. Bartley, see GCA Closing Argument pp. 11-16 and SOR 39-53.]

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and unique identification number for the engine or turbine;

(b) location of the source (latitude and longitude);

(c) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule as defined in 20.2.50.112 NMAC; and

(d) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time stamp(s), including GPS of the location, of an inspection, maintenance, or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the person(s) conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine for a period of five years. The records shall include:

(a) make, model, and serial number for the tested engine or turbine;

(b) the date and time stamp(s), including GPS of the location, of

any monitoring event, including sampling or measurements;

(c) date analyses were performed;

(d) name of the person(s) and the qualified entity that performed the analyses;

(e) analytical or test methods used;

(f) results of analyses or tests;

(g) calculated emissions of NOx and VOC in lb/hr and tpy; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine or turbine to meet the requirements of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine or turbine's actual hours of operation, to demonstrate that an equivalent allowable ton per year emission reduction as set forth in table 1 or table 3 of Paragraph (2) or (7) of Subsection B of 20.2.50.113 NMAC, or the ninety-five percent emission reduction requirement is met.

NMED: Subsection D of 20.2.50.113 sets forth specific reporting requirements for owners and operators of new and existing engines and turbines. These provisions include requirements for owners and operators to maintain records of certain information on units subject to this Section, including the make, model, and serial number; a copy of the engine, turbine, and control device manufacturer specifications; information on the initial and annual emissions testing; hours of operation; and information documenting that emissions reductions realized through the reduction in hours of operation is equivalent to a 95% reduction in NOx and VOC emissions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 37.

[NMOGA and Kinder Morgan's earlier proposal to add two new requirements at paragraphs (5) and (6) have been addressed.]

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.113 NM–C - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.113 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 37.

<u>NMED:</u>

Estimated Emissions Reductions Resulting from Section 20.2.50.113

<u>NOx Reductions - Engines</u>

ERG estimated total baseline allowable NOx emissions from all 4,718 operating internal combustion engines located in the Subject Counties, or designated as "Portable." Allowable NOx emissions from those units were 62,005 tpy. ERG then estimated the NOx emission reductions from implementing the proposed regulations on existing engines. Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy, leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline emissions. See NMED Exhibit 56 - ICE Reductions and Costs NO_2 Spreadsheet. Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy, leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline emissions. *See* NMED Exhibit 32, pp. 46-48; NMED Exhibit 56 - ICE Reductions and Costs NO2 Spreadsheet.

<u>VOC Reductions - Engines</u>

ERG estimated VOC emissions from the entire inventory of 4,276 operating internal combustion engines located in the Subject Counties or designated as "Portable" at 24,224 tpy of VOC. ERG then estimated the VOC emission reductions that would be achieved by implementing the proposed requirements for existing engines. For the 186 uncontrolled engines, ERG estimated reductions of 1,663 tpy of VOC based on the use of an add-on control to achieve the required emission reduction to meet the proposed standard, leading to a 6.8% overall reduction in VOC emissions from existing engines. *See* NMED Exhibit 32, pp. 46-49; NMED Exhibit 57 – ICE Reductions and Costs VOC Spreadsheet.

<u>NOx Reductions - Turbines</u>

ERG calculated the allowable NOx emissions from the entire inventory of 160 active combustion turbines located in the Subject Counties. Emissions from these units total 10,313 tpy of allowable NOx. ERG then examined the effect of implementing the proposed regulations on the 51 unregulated and uncontrolled combustion turbines with a horsepower rating greater than 1,000. Applying controls to these units results in a reduction of 3,377 tpy of allowable NOx. The reductions are based on the percent reductions by engine horsepower rating as indicated above. Adding controls to uncontrolled combustion turbines with horsepower ratings greater than 1,000 would result in a 32.7% overall reduction in NOx emissions. See NMED Exhibit 58 – Turbines Reductions and Costs NO_2 Spreadsheet. *See* NMED Exhibit 32, pp. 49-50; NMED Exhibit 58 – Turbines Reductions and Costs NO_2 Spreadsheet.

<u>VOC Reductions - Turbines</u>

ERG estimated the emission reductions from 39 turbines without controls as the difference between the allowable VOC emissions in the permit data and the estimated NMNEHC emissions under the proposed emission limits. The emission reductions are based on the use of an add-on control (oxidation catalyst) to achieve the VOC (NMNEHC) emission limits in the proposed NM standards. Adding controls to these 39 combustion turbines would reduce VOC emissions by 353 tpy, leading to a 49.9% overall reduction in VOC emissions from combustion turbines. *See* NMED Exhibit 32, pp. 50-52; NMED Exhibit 59 – Turbines Reductions and Costs VOC Spreadsheet.

Estimated Costs of Section 20.2.50.113

The annualized costs of NOx emission reductions for the 1,866 uncontrolled and partially controlled natural gas-fired spark-ignition engines were estimated by applying cost equations for the different types and sizes of engines, as described on pages 52-54 of NMED Exhibit 32.

For 2-stroke and 4-stroke lean-burn engines, costs were calculated for adding Low Emission Combustion ("LEC") Technology as a retrofit, as described on pages 53-54 of NMED Exhibit 32, and NMED Exhibit 56. The total annualized costs of adding LEC to lean-burn spark ignition engines and NSCR to rich-burn spark ignition engines was estimated to be $120,267,152 per year, at an average annual cost per engine of $64,452 and a cost per ton of NOx reduced of $6,717.

The annualized costs of VOC emission reductions for natural gas-fired spark-ignition engines were calculated by applying the control costs for adding oxidation catalysts to 172 uncontrolled lean burn engines. Total annualized costs for these 172 engines were estimated at approximately $1,626,842 per year at an average annual cost per engine of $9,458 and a cost per ton of VOC reduced of $990.ERG estimated the total annual costs for internal combustion engines, based on low emission combustion retrofits for lean burn engines at $104 million. NMED Exhibit 32, p. 55.

The annualized costs of NOx emission reductions were estimated for the 51 uncontrolled natural gas-fired combustion turbines, as described on page 55 of NMED Exhibit 32, and NMED Exhibit 58. The total annualized costs of NOx emission reductions for these 51 natural gas-fired turbines were estimated at $13,764,391 per year at an average annual cost per turbine of $269,890 and a cost per ton of NOx reduced of $4,076. *Id.* at 55-56.

To estimate costs of VOC reductions for turbines, ERG assumed that an oxidation catalyst is added as a control device to 39 uncontrolled turbines that are unregulated by an NSPS or NESHAP, and that have allowable VOC emissions that exceed the proposed limits. The total annualized costs of VOC emission reductions for 39 natural gas-fired turbines were estimated at $3,392,186 per year, with an average annual cost per turbine of $86,979 and a cost per ton of VOC reduced of $9,608. *See id.*

Cost estimates were adjusted based on modifications to Section 20.2.50.112 as described in NMED Rebuttal Exhibit 1, pp. 32-33, 38-39, and 44-48.

The Board should find that the estimated costs associated with Section 20.2.50.113 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

NMOGA: The Board should adopt the Department's proposal because it requires reasonable and aggressive emissions reductions. Industry stakeholders engaged extensively with the Department prior to and during the hearing to reach agreement on appropriate, aggressive standards that both existing and new engines and turbines could meet. The final result, encapsulated in the Department's September 16 and December 16 redlines, should not be disturbed. As Mr. Lisowski testified, there is no "blanket" technology that can meet all needs. Lisowski testimony, Tr. 6:1726:25-6:1727:7. Many of the low emitting combustor (LEC) controls are already implemented on existing turbines or else they may be small bore engines where these controls are not practical. Lisowski testimony, Tr. 6:1725:17-6:1727:7. Non-selective catalytic reduction (NSCR), used on many rich burn engines, is already in place and limited in further reduction by drift issues. Lisowski testimony, Tr. 6:1729:13-6:1730:8. Selective catalytic reduction (SCR) is not cost-effective or workable in the oil field as it is too expensive and requires full-time staffing, which is not available at most facilities. Lisowski testimony, Tr. 6:1730:9-6:1731:3. Based upon this testimony and supporting testimony from Mr. Dutton, Mr. Sheldon and Ms. Witherspoon, NMED, engine and turbine manufacturers, and industry reached an agreement on what is practical for New Mexico. Kuehn testimony, Tr. 6:1682:10-13. Mr. Lisowski also explained why the existence of the Alternative Compliance Plan did not mean that lower limits, such as the 1.2 g NOX/bhp-hr standard advocated by the environmental groups, could not feasibly be met. Lisowski testimony, Tr. 9:2993:13-18; 9:2999:25-9:3001:11. And Ms. Kuehn agreed that the original, more stringent, NMED proposal had not recognized the off ramps and exemptions found in the other regulatory programs or the differing field and gas conditions in New Mexico. Kuehn testimony, Tr. 6:1701:23-6:1702:5.

NMOGA also urges the Board to support the Department's decision to exclude relocations and like-kind exchanges from the definition of "construction." Kuehn testimony, Tr. 6:1686:1-6. This decision facilitates emissions reductions in the oil field by allowing engines to be "right sized" to the need, preventing them from running below optimal conditions (which would result in higher actual emissions), and allowing for more comprehensive maintenance in the shop as opposed to the field, which helps to keep the overall engine and turbine fleet in better repair. Initial concerns from the National Park Service that old turbines would be "dumped" on New Mexico were ameliorated once they understood that all existing units, including relocated ones, would be subject to the existing source emissions limits. Devore testimony, tr. 8:2401:2-8:2402:2. Similarly, the Board should support CO testing as a surrogate for VOC testing, because it is cheaper and will enable operators to tune their engines more efficiently. Lisowski testimony, tr. 6:1734:2-8.

The National Park Service in its pre-filed testimony requested that emissions limits be established for smaller engines. Multiple experts testified that the proposed limits were not achievable in a cost-effective manner and urged that they not be adopted. *See* Trent, Tr. 6:1814:9-16; Sheldon and Dutton, Tr. 6:1757:1-6:1760:13, Lisowski Tr. 9:2990:20-9:2991:20. Based on this testimony, NPS withdrew its request to regulate the smaller engines. Devore testimony, Tr. 8:2399:24-8:2400:9.

NMED's initial proposal applied 20.2.50.113 NMAC to portable engines, which include nonroad engines. NMED has since revised its proposal so that proposed 20.2.50.113 NMAC does not apply to nonroad engines. The Board should follow the Department's course in excluding nonroad engines from the rule because emissions standards for such engines are subject to exclusive federal control. 42 U.S.C. § 7543(e); *Engine Mfrs. Ass'n v. U.S. E.P.A.*, 88 F.3d 1075, 1087-88 (D.C. Cir. 1996) ("states must be preempted from adopting any regulation for which California could receive authorization."); *Pac. Merch. Shipping Ass'n v. Goldstene*, 517 F.3d 1108, 1113 (9th Cir. 2008) ("we join the D.C. Circuit and hold that the implied preemption of § 209(e)(2) applies to 'any nonroad vehicles or engines,' including new and non-new sources.").

IPANM: IPANM had earlier challenges in this subsection, but withdrew them based on NPS's testimony.

20.2.50.114 COMPRESSOR SEALS:

NMED: **Description of Equipment or Process**

Compressors are used throughout the oil and natural gas industry to compress gas for processing, movement through pipelines, and other needs. Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported in pipelines from the production site, through the processing and supply chain, and to the consumer. Vented emissions from compressors occur from seals (wet seal compressors) or packing surrounding the mechanical compression components (reciprocating compressors) of the compressor. These emissions typically increase over time as the compressor components begin to wear and degrade. NMED Exhibit 32, p. 57.

Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by a reciprocating internal combustion engine. Emissions occur when natural gas leaks around the compressor piston rod when pressurized natural gas is in the cylinder. The compressor piston rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. Over time, the rings become worn and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder. *Id.* at 57-58.

Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for pipeline transport of natural gas in the natural gas processing and transmission segments of the industry. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Many centrifugal compressors use wet (i.e., oil-filled) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. Other compressors, including most newer compressors, use a dry seal with a mechanical barrier around the rotating shaft to prevent natural gas from escaping. *Id.* at 58-60.

Control Options

VOC emissions from reciprocating compressor rod packing can be minimized by replacing the rod packing on a regular basis before it becomes excessively worn. A typical regulatory schedule is to replace the rod packing seals after every 26,000 hours of operation or every 36 months, whichever is later. A second control option is to collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, a fuel cell, a process stream, or to be used as fuel. Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. NMED Exhibit 32, p. 60.

Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. A wet seal fluid degassing system that is designed to capture the released methane and VOC can be used to separate the entrained gas from contaminated seal oil in a separator and route it to a seal oil demister to remove entrained seal oil before routing the gas to a control device, a process, for use as a fuel, or to the suction side of a compressor to be pressurized and put back into the pipeline or another use. The seal oil from the bottom of the high-pressure seal oil degassing separator flows to the atmospheric degassing separator where the remaining, but now reduced, volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system. *Id.* at 61-62.

Rule Language

The proposed requirements in Section 20.2.50.114 are based on similar requirements in NSPS Subpart OOOOa, as discussed in NMED Exhibit 32, pp. 64-65.

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of 20.2.50.114 NMAC.

NMED: Section 20.2.50.114 applies to centrifugal compressors using wet seals and reciprocating compressors located at tank batteries, gathering and boosting stations, and natural gas processing plants. Centrifugal compressors and reciprocating compressors located at well sites and transmission compressor stations are not subject to the requirements of Section 20.2.50.114. The Department proposed substantial revisions to this provision based on comments from NMOGA and Kinder Morgan, as outlined in NMED Rebuttal Exhibit 1, pp. 48-50.

NMED proposed to remove transmission compressor stations from applicability of Section 20.2.50.114 based on testimony submitted by Kinder Morgan. NMED estimated VOC emissions from transmission compressor stations using data reported to the GHGRP by operators of those facilities in New Mexico. *See* NMED Rebuttal Exhibit 6 - GHGRP Data for NG Transmission Compression Spreadsheet. The GHGRP data included methane emissions from twelve (12) New Mexico facilities identified as transmission compressor stations. Kinder Morgan's testimony included gas analysis data for five stations showing the average VOC content of their pipeline gas is 0.574%, with a range of 0.206% to 0.775%. *See* Kinder Morgan NOI, Attachment B. Assuming that the methane emissions in the GHGRP data include 0.574% VOC by weight, the total VOC emissions from those twelve stations in the GHGRP is 13 tpy VOC. The range per station is 0.22 tpy to 4.53 tpy VOC. Based on this analysis, NMED agreed that it is appropriate to remove transmission compression stations that are handling pipeline quality natural gas from applicability of this Section. NMED Rebuttal Exhibit 1, pp. 49-50.

The Board should adopt NMED's proposal for the reasons stated in NMED Exhibit 32, pp. 62, 64-68, and NMED Rebuttal Exhibit 1, pp. 48-50.

[NMOGA's earlier proposal to remove Section 20.2.50.114 entirely is not part of its final proposal. NMED did agree to numerous revisions to this Section proposed by NMOGA, as detailed in NMED Rebuttal Exhibit 1, p. 49.]

Kinder Morgan: Kinder Morgan supports NMED's reasonable position to exempt transmission compressor stations from this 20.2.50.114 NMAC addressing compressor seals. The VOC content of the natural gas that Kinder Morgan transports is very low. Detailed analyses of data from Kinder Morgan's operations shows that most of Kinder Morgan's centrifugal wet seals emit 0 or close to 0 tpy of VOC from their degassing vents. Rebuttal NOI, Attachment Z. In light of these low emissions, controlling emissions from existing wet seals would almost certainly be cost-prohibitive. Id. Ex. XIV, at 2–3. Replacing wet seals with dry seals also presents cost concerns and could result in undesirable operational consequences that further exacerbate costs. Id. at 3–4.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor with wet seals shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor 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 of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing, and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

NMED: Paragraphs (1) and (2) of Subsection B of Section 20.2.50.114 set forth emissions standards for existing compressors. Owners and operators of existing centrifugal compressors are required to control VOC emissions from centrifugal compressor wet seal fluid degassing systems by at least 95 percent within two years of the effective date of Part 50. Emissions must be captured and routed through a closed vent system to a control device, recovery system, fuel cell, or a process stream. Owners and operators of existing reciprocating compressors must either replace the rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is later, or collect VOC emissions from the rod packing and route them through a closed vent system to a control device, recovery system, fuel cell, or a process stream. For the first option, the owner or operator must begin counting the hours of operation upon the effective date of Part 50. For the second option, the owner or operator has two years from the effective date to implement to begin collecting and routing the emissions. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 62-63, 64-68; and NMED Rebuttal Exhibit 1, p. 49.

(3) The owner or operator of a new centrifugal compressor with wet seals shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-five percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor 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 and route them via a closed vent system to a control device, a recovery system, fuel cell, or a process stream.

NMED: Paragraphs 3 and 4 of Subsection B of Section 20.2.50.114 sets forth emissions standards for new compressors. Owners and operators of new centrifugal compressors are required to control VOC emissions from wet seal fluid degassing systems by at least 98 percent upon startup, capturing and routing emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream. For new reciprocating compressors, rod packing must be replaced after every 26,000 hours of operation or every 36 months, whichever is later, or emissions must be collected from the rod packing using a closed vent system to a control device, a recovery system, fuel cell or a process stream. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68; and NMED Rebuttal Exhibit 1, p. 49.

(5) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

NMED: Paragraph (5) of Subsection B of Section 20.2.50.114 provides that an owner or operator complying with the emissions standards in Subsection B of Section 20.2.50.114 through use of a control device must comply with the control device requirements in 20.2.50.115. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68.

C. Monitoring requirements:

(1) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates as designed and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.114 sets forth specific monitoring requirements for compressors. The Department is proposing to remove Paragraph 1 from its most recent proposal because that requirement is redundant with the requirement in former Paragraph 4. Owners and operators complying with the emission standards for reciprocating compressors are required to continuously monitor the hours of operation with a non-resettable hour meter, and track the number of hours from initial startup or from the previous reciprocating compressor rod packing replacement. Owners and operators of reciprocating compressors that are collecting emissions and routing those emissions through a closed vent system to a control device, a recovery system, fuel cell or a process stream are required to monitor the collection system semi-annually to ensure that it continues to operate as designed. Owners and operators must comply with the general monitoring provisions in Section 20.2.50.112. The Department's proposal includes revisions in response to comments by NMOGA. *See* NMED Rebuttal Exhibit 1, p. 49. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 63, 64-68; and NMED Rebuttal Exhibit 1, p. 49.

NMOGA adds support: See Lisowski rebuttal testimony NMOGA Exhibit 43:12:18-21. Mr. Lisowski testified that it is not an issue to install non-resettable meters on compressors and is already used by most operators.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location (latitude and longitude) of the centrifugal compressor;

(b) the date of construction or reconstruction of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the person(s) conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and unique identification number or equivalent identifier of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

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

(a) the location (latitude and longitude) of the reciprocating compressor;

(b) the date of construction or reconstruction of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since the effective date, initial startup after the effective date, or the last rod packing replacement, as applicable;

(ii) data showing the effectiveness of the rod packing emissions collection system, as applicable; and

(iii) the time and date of the inspection, the person(s) conducting the inspection, a description of any problems observed during the inspection, and a description of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

NMED: Subsection D of Section 20.2.50.114 sets forth recordkeeping requirements for compressors. Owners and operators of centrifugal compressors using wet seal fluid degassing systems are required to maintain records of the following: location of the compressor; date of construction or reconstruction of the compressor; required monitoring data; and the type, make, model and identification number or equivalent identifier of the control device used to comply with the emission standards. Owners and operators of reciprocating compressors are required to maintain a record of the following: location of the compressor; date of construction or reconstruction of the compressor; and the required monitoring data. Owners and operators must comply with the general recordkeeping provisions in Section 20.2.50.112.

The Department's proposal includes revisions in response to comments by NMOGA. NMED Rebuttal Exhibit 1, p. 49. The Department has also proposed additional revisions removing references in this section to "modification," because that term is undefined in the rule and is encompassed within the definition of "reconstruction." The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 62-65, and NMED Rebuttal Exhibit 1, p. 49.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.114 NM–C - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.114 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 62-63.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.114

ERG's analysis of emissions reductions for compressors is detailed in NMED Ex. 32, pp. 65-68. For the 2,612 reciprocating compressors in the NMED data, total annual emission reductions with increased rod packing replacement were estimated to be 5,325 tpy VOC, a 57.5 percent reduction, and emissions after replacement of rod packing were estimated to be 3,935 tpy VOC. *See* NMED Ex. 64 – Compressor Seals - Reciprocating Engines Spreadsheet. For centrifugal compressors, ERG estimated overall VOC reductions would be 2,087 tpy VOC, and the overall percent VOC emission reduction would be 93%. *See* NMED Exhibit 66 – Compressor Seals - Turbines Spreadsheet.

For reciprocating compressors, ERG estimated the annual cost per compressor for rod packing replacement to be $2,237 per year for a compressor in the gathering and boosting sector, and $1,695 per year for a compressor in the processing sector. These annual costs are incremental costs compared to the annual costs of replacing the rod packing every four years. ERG estimate the total cost for replacing rod packing every three years for all 2,612 reciprocating compressors to be $5,778,289. For centrifugal compressors, ERG calculated the annualized cost for installing a degassing system at each of the 36 locations with centrifugal compressors that would be affected by Part 50 based on the number of compressors at that site, not for each individual compressor. The total initial capital cost for installing a degassing system at the 36 compressor sites is $2,735,150 and the annualized cost of installing a degassing system at the 36 compressor sites is $667,078. Full details on ERG's cost estimates for compressors can be found in NMED Exhibit 32, pp. 68-70; NMED Exhibit 64 – Compressor Seals – Reciprocating Engines Spreadsheet; and NMED Exhibit 66 – Compressor Seals – Turbines Spreadsheet. The Board should find that the estimated costs associated with Section 20.2.50.113 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

<u>NMED:</u> **Description of Equipment or Process**

A control device is any mechanical, thermo, or chemical means to capture, convert, destroy, or recover air contaminants. The purpose of control devices as defined in Part 50 is the reduction of VOCs and NOx. Some control devices are specific to a particular process or type of equipment, while others can be used for multiple processes or types of equipment. Examples of control devices include, but are not limited to, open flares, enclosed combustion devices (ECDs), thermal oxidizers "TOs), vapor recovery units (VRUs), fuel cells, condensers, and catalytic converters (oxidative, selective, and non-selective). A control device may also include any other air pollution control equipment or emission reduction technologies approved by the Department to comply with emission standards in Part 50. NMED Exhibit 32, p. 70.

Open Flares

Open flares or "flaring" refers to the routing of natural gas from anywhere in the process to a device where the gas is combusted as it leaves the tip of the flare. Flaring is a high-temperature oxidation process used to burn or incinerate waste gases containing combustible components such as VOCs, natural gas (methane), carbon monoxide (CO), and hydrogen (H2). Flares convert, or destroy, waste gases into less harmful components (ideally, water vapor and carbon dioxide). The flare system consists of a header, stack, tip, and ignition system. Gas is sent to the flare through a header system and is combusted as it exits the flare stack at the tip. The flare tip is designed to ensure the proper mixing of gas and air to achieve the proper burn efficiency. Ignition of the gas stream is through the use of a continuously burning pilot or auto-ignition system. Flaring is a necessary part of drilling and completion activities, oil and natural gas field production, pipeline gas gathering, and facility processing of oil and natural gas because of safety considerations (personnel and equipment) and its effectiveness in combusting harmful emissions (environmental). *Id.* at 71.

Enclosed Combustion Devices and Thermal Oxidizers

Enclosed combustion devices use a high-temperature oxidation process to control VOCs in many industrial settings because the enclosed combustor can normally handle fluctuations in concentration, flow rate, heating value, and unreactive (i.e., noncombustible) compounds found in the gas stream. For this analysis, it is assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuous basis. Combustion devices can be designed to meet a 98 percent control efficiency, and can control emissions by 98 percent on average, or more in practice when properly operated. Combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions. A typical combustor used to control emissions from storage vessels in the oil and natural gas sector is an enclosed combustion system. *Id.* at 71-72.

Thermal oxidizers – also referred to as direct flame incinerators, thermal incinerators, or afterburners – can also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e. vented) to the atmosphere. *Id.* at 72.

Vapor Recovery Units

Vapor recovery units ("VRUs") route vapors from an emission source back to the inlet line of a separator, to a sales gas line, or to another process line for beneficial use, such as use as a fuel. A VRU is often referred to as a compressor that is used to boost recovered vapors back into the line. In a typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator or suction scrubber to collect any condensed liquids, which are recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite. *Id.* at 73.

Condensers

A condenser is a heat exchanger used to condense a gaseous substance into a liquid state through cooling. Condensers are often used to control VOC emissions from glycol dehydration units by condensing the organic vapors from the regenerator still vent. *Id.* at 74.

Fuel Cells

A fuel cell is an electrochemical cell that converts the chemical energy of a fuel (typically hydrogen but may also be methane or organic vapors) and an oxidizing agent (commonly oxygen) into electricity through oxidation and reduction reactions that convert the fuel into water vapor (in the case of hydrogen fuel) or into carbon dioxide and water vapor (in the case of methane or organic vapors). The use of fuel cells has been investigated as a potential VOC emission control option for the surface coating industry, but has not yet been demonstrated for controlling VOC emissions from oil and natural gas production operations. *Id.*

Gaseous Emission Control of Stationary Internal Combustion Engines

Gas compressor operations are an essential element of oil and gas production. To produce oil and natural gas and keep natural gas pressures at the level required to move gas from the wellhead to the consumer, compressors and the associated driver are found at multiple locations in the natural gas value chain. In addition to driving compressors, engines may also be used as the driver for power generators that provide electrical power to sites that are not connected to the commercial electrical grid. *Id.*

Catalytic Converters (oxidative, selective, and non-selective)

Stationary engines, typically fueled by natural gas or propane, are widely used for prime power and for gas compression. In gas compression, the types of engines are either rich-burn or lean-burn. The difference between rich-burn and lean-burn engine operation lies in the air-to-fuel ratio: a rich-burn engine is characterized by excess fuel in the combustion chamber during combustion, while a lean-burn engine is characterized by excess air in the combustion chamber during combustion. For gas transmission, engines are typically lean-burning. Gas engines are also used for prime power applications, especially where it is convenient to connect a natural gas line to the engine. Depending on the application, engines in oil and natural gas operations range in size from relatively small (approximately 50 hp) for certain types of pumps and generators to thousands of horsepower for natural gas compressors at transmission compression stations. Different emission control technologies have to be applied to engines depending on their air-to-fuel (A/F) ratio. This is because the exhaust gas composition differs depending on whether the engine is operated in a rich, lean, or stoichiometric burn condition. *Id.* at 74-75.

Rule Language

The proposed general requirements for control devices in Paragraphs (1) through (5) of Subsection B of Section 20.2.50.115.B are based on similar rules for closed vent systems and control devices in Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38), Colorado Reg. 7, Section II.C.5 (NMED Exhibit 39), NSPS Subpart OOOOa (NMED Exhibit 36), and EPA's NSPS regulations at 40 C.F.R. 60, Subpart A – General Provisions ("NSPS Subpart A"). The proposed requirements for closed vent systems for centrifugal compressor wet seal fluid degassing systems in Paragraph (6) of Subsection B of Section 20.2.50.115 are based on Colorado Reg. 7, Section I.J.1; and NSPS Subpart OOOOa, Section 60.5380a. The proposed requirements for open flares in Subsection C of Section 20.2.50.115 are based on NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b). The proposed requirements for enclosed combustion devices and thermal oxidizers in Subsection D of Section 20.2.50.115 are based on Pennsylvania GP-5, Section J; Colorado Reg. 7, Sections I.C.1 and II.B.2; NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b). The proposed requirements for VRUs in Subsection E of Section 20.2.50.115 are based on Pennsylvania GP-5, Section J; and NSPS Subpart OOOOa, Section 60.5412a. *See* NMED Exhibit 32, pp. 78-79.

A. Applicability: These requirements apply to control devices and closed vent systems as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

NMED: The requirements of Section 20.2.50.115 apply to control devices and closed vent systems used to comply with the emission standards and emission reduction requirements found in Part 50. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 70-78.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle the reasonably expected range

of inlet VOC or NOx concentrations or volumes.

(3) The owner or operator shall inspect control devices visually or consistent with applicable federally approved inspection methods at least monthly to identify defects, leaks, and releases, and to ensure proper operation. Prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, in order to minimize venting of unburnt gas to the atmosphere.

(5) The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, natural gas driven pneumatic pump, or storage vessel using a control device or routing emissions to a process shall:

<u>Oxy proposes to insert "flowback vessel" related to proposed new Section 127:</u>

"The owner or operator of a permanent closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, natural gas driven pneumatic pump, ~~or~~ storage vessel <u>or</u> <u>flowback vessel</u> using a control device or routing emissions to a process shall:"

(a) ensure the control device or process is of sufficient design and capacity to accommodate the expected range of emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that emissions from the affected equipment are routed to the control device or process; and

(c) have the assessment certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of closed vent system(s) in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system assessment was prepared under my direction or supervision. I further certify that the closed vent system assessment was conducted, and this report was prepared, pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(d) an owner or operator of an existing closed vent system shall comply with the requirements of Paragraph (5) of Subsection B of 20.2.50.115 NMAC within three years of the effective date of this Part and within 90 days of startup for a new closed vent system.

(6) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include the unique identification number, type of unit, manufacturer name, make, model, capacity, and destruction or reduction efficiency data.

NMED: Subsection B of Section 20.2.50.115 sets forth general requirements for control devices and closed vent systems. Control devices must be designed and sized to achieve the emission standards required by Part 50, and must be installed, operated, and maintained consistent with manufacturer specifications and good engineering and maintenance practices. Each device must be inspected at least monthly to ensure proper operation, and must operate as a closed vent system that minimizes venting of unburnt gas to the atmosphere. Permanent closed vent systems for the equipment specified in Paragraph (5) of Subsection B must have a design and capacity to accommodate the expected emissions from the affected sources and owners and operators must conduct an assessment to ensure the emissions are routed to the control device or process. This assessment must be certified by a professional engineer or an in-house engineer with relevant expertise. Existing closed vent systems have three years from the effective date to comply with the requirements of Paragraph (5), while new closed vent systems must comply within 90 days of startup. Manufacturer specifications for control devices must be kept on file by the owner or operator and must include identifying information, specific operational parameters (e.g., maximum rated capacity) and control efficiency data. The Board should adopt these proposals for the reasons stated in NMED Exhibit 32, pp. 75-76, 78; NMED Rebuttal Exhibit 1, pp. 50-52.

[Earlier proposed revisions to Subsection B by GCA and NMOGA are not in their final proposals following adjustments to NMED's earlier language.]

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare, and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

NMOGA would revise Section C(1)(a):

(a) the flare shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare, and combustion shall be

maintained for the duration of time that <u>sufficient</u> gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity. <u>Failure to combust during the auto-igniter reignition cycle is not a violation of this requirement.</u>

<u>NMOGA:</u> There is not sufficient gas at the end of an event to sustain combustion. That should not be a violation. By definition, there will be a period between the "sparks" generated by the autoigniter and some gas could be emitted in those periods. This language clarifies that this period is not a violation.

<u>NMED opposes this revision:</u> NMOGA proposes revisions to Subsection C, Subparagraph 1(a) providing that combustion shall be maintained for the duration of time that sufficient gas is sent to the flare. The Department disagrees with this proposal. This proposal would create uncertainty in what amount of gas should be deemed "sufficient." Further, the addition of "sufficient" is unnecessary because the rule does not require 100% combustion efficiency for flares, and amounts of gas that are not sufficient for combustion can be included within the percentage of gas that is not required to be combusted.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (c) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following no later than one year after the effective date of this part, unless otherwise specified:

(i) a flare 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 when gas is being sent to the flare.

<u>NMOGA would add a sentence to the end of C(1)(b)(i):</u>

"Failure of the flare to be lit prior to the auto-igniter reignition cycle is not a violation of this requirement."

By definition, there will be a period between the "sparks" generated by the autoigniter and some gas could be emitted in those periods. This language clarifies that this period is not a violation.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream shall be equipped with a continuous pilot.

NMOGA: NMOGA would insert the word **"waste"** between "continuous" and "gas stream" in paragraphs (iii) and (iv), proposing this as a clarification so that it is clear the pilot fuel is not a continuous gas stream implicating this requirement.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 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. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(e) the owner or operator shall repair the flare within three business days of any thermocouple or other flame detection device alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto-igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto-igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions;

(d) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm

activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the most recent gas analysis for the gas being flared, including VOC content and heating value; and

NMOGA would insert words **"if any"** after "heating value" in paragraph (d): At midstream facilities, there may not be a gas analysis because many facilities are combined prior to flaring.

(e) the date and time stamp(s), including GPS of the location, of any monitoring event.

NMED: Subsection C of Section 20.2.50.115 sets forth specific requirements for open flares. Flares must be sized and designed to ensure proper combustion efficiency to combust the gas sent to the flare and maintain combustion for the duration of time that gas is sent to the flare. Owners and operators using open flares are required to install a continuous pilot, auto-igniter, or require manual ignition no later than one year after the effective date of Part 50 for both new and existing flares. Flares with a continuous pilot flame or auto ignitor must be equipped with a system to ensure that a flame is present at all times when gas is being sent to the flare. Owners and operators of manually ignited flares must inspect and ensure a flame is present upon initiating a flaring event.

Existing flares controlling a continuous gas stream must be equipped with a continuous pilot. For existing flares at facilities with an average daily production of 10 bbls/day of oil or 60,000 scf/day of natural gas, owners and operators are required to install an auto-igniter, continuous pilot, or flare malfunction alarm technology upon replacement or reconstruction. Flares must be operated with no visible emissions except as provided. Flares must be designed so that observers can determine proper operation by visual observations or other means such as continuous monitoring technology, and all repairs must be completed within three business days of an alarm activation. Flares with a continuous pilot or auto-ignitor must be continuously monitored for the presence of a pilot flame or flame during flaring using a thermocouple equipped with an alarm, and manually ignited flares must be continuously visually monitored for the presence of a flame during a flaring event. Owners and operators are required to perform quarterly EPA Method 22 (40 C.F.R. Part 60, Appendix A) observations to ensure compliance with visible emissions and opacity limits. *See* NMED Exhibit 67 – EPA Reference Method 22 – *Visual determination of Fugitive Emissions from Material Sources and Smoke from Flares* (January 14, 2019). Inspections and monitoring events must be date and time stamped.

Owners and operators must keep records of alarm activation, cause of the alarm, corrective actions taken and name of personnel conducting the action, and any maintenance activities performed. Records must also be kept with respect to EPA Method 22 observations, monitoring of manual flares, and results of gas analyses for the gas being flared. Owners and operators must comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 76-77, 79 and NMED Rebuttal Exhibit 1, pp. 53-54.

[NMOGA's earlier proposals to delete Subsection C(1)(b)(ii), to remove the 10 barrels of oil a day threshold, and to require that only new flares be monitored, are not part of its final proposal.]

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

NMOGA would delete paragraph (4) of Section C because this language appears in Subsection G.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall be properly sized and designed to ensure proper combustion efficiency to combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new ECD/TO with a continuous pilot flame or an auto-igniter upon startup. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than two years after the effective date of this Part.

(c) ECD/TO 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 when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO. New ECD/TOs shall comply with this requirement upon startup, and existing ECD/TOs shall comply with this requirement within 2 years of the effective date of this Part.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto-igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto-igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes. The observation may be terminated if visible emissions are observed and recorded and action is taken to address the visible emissions.

(c) prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the monitoring requirements of this Part.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of thermocouple, other approved technology, or flame detection device alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the person(s) conducting the inspection, and any maintenance activities performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the date and time stamp(s), including GPS of the location, of any monitoring event; and

(d) the results of the most recent gas analysis for the gas being combusted, including VOC content and heating value.

NMOGA would insert words **"if any"** after "heating value" in paragraph (d): Midstream facilities receive gas from multiple facilities and may not have a traditional gas analysis.

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

NMED: Subsection D of Section 20.2.50.115 sets forth requirements for combustion devices and thermal oxidizers ("ECD/TOs"). ECD/TOs must be designed and sized to ensure proper combustion efficiency to gas sent to the equipment. Owners and operators must install continuous pilot flames or auto-igniters upon startup for new ECD/TOs, or within two years of the effective date of Part 50 for existing ECD/TOs. New ECD/TOs must operate with a continuous flame present and with no visible emissions during flaring events upon startup, and existing ECD/TOs must comply with this requirement within 2 years of the effective date.

ECD/TOs with a continuous pilot must be monitored continuously for the presence of a pilot flame. When an auto igniter is used, the presence of a flame must be continuously monitored during flaring using a thermocouple or alternative equivalent technology approved by the Department. Owners and operators are required to perform quarterly EPA Method 22 observations to ensure compliance with visible emissions and opacity limits. Inspections and monitoring events must be date and time stamped.

Owners and operators of ECD/TOs are required to keep records of alarm activation, cause of the alarm, corrective action taken, name of personnel conducting the inspection, and any maintenance activities performed. Additionally, owners and operators must record the results of the quarterly EPA Method 22 observations. Gas analysis results must be recorded for the combustion gas to include the VOC content and heating value.

Owners and operators of ECD/TOs are required to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 77, 79 and NMED Rebuttal Ex. 1, pp. 54-55.

[NMOGA's earlier proposal to remove the requirement for quarterly monitoring of visible emissions from ECD/TOs in paragraph (2)(b) is not part of its final submittal.]

NMOGA would delete Section D, paragraph 4: This language appears in Subsection G.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

NMOGA would delete the word **"all"** before "VOC emissions": It is impossible to prevent all VOC emissions such as during maintenance or VOCs that cannot be captured. Meyer rebuttal testimony, NMOGA Exhibit 42:2:18-27.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime, unless otherwise approved in an air permit issued prior to the effective date of this Part. Alternatively, the owner or operator may shut down and isolate the source being controlled by the VRU. For sites that already have a VRU installed as of the effective date of this Part, the owner or operator shall install backup control devices or redundant VRUs within three years of the effective date of this Part.

NMOGA would add the words **"except during a facility-wide upset"** at the beginning of (b): If there is a facility-wide upset, it would cause all VRUs (and likely other control devices) to go down. In most cases, exhaust gases would be sent to a flare, if one is present, in such situations. Meyer rebuttal testimony, NMOGA Exhibit 42:2:25-27. Moreover, NMOGA does not believe redundant control requirements for VRUs are appropriate. NMOGA generally supports the standards for control devices in the Department's latest proposal, except that the record does not demonstrate that the more stringent redundant control requirements under 20.2.50.115.E.1(b) NMAC are more protective of ozone concentrations. The Board should not adopt these requirements. Under proposed 20.2.50.115.E(1)(b), owners and operators must "control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU during the period of VRU downtime." To the best of NMOGA's understanding, the Department has not estimated the costs or emissions reductions associated with a redundant control device. Because these control devices are required to be used only during "startup, shutdown, maintenance, or other VRU downtime" and such events are inherently infrequent, the emissions reductions to be gained from redundant controls are slight, while the cost of acquiring, installing, and maintaining these redundant controls are relatively similar to the costs associated with acquiring, installing, and maintaining the primary control device. Consequently, the cost-per-ton reduced of the redundant control requirement is excessive.

The redundant control requirement also has no federal corollary. As such, the Board must find that these requirements are more protective than federal law to support their adoption. There is no evidence in the record to suggest that the minimal emissions reductions associated with redundant controls would have a demonstrable impact on ozone concentrations. For this reason, the Board should not adopt these standards. If the Board determines against the weight of evidence to adopt these standards, NMOGA urges the Board to not require redundant controls during a facility-wide upset. The reason for this is simple: the conditions that caused the primary VRU to be down will also impact any redundant controls. To ensure this standard is technically feasible, it should not apply during such events.

Beyond this concern, the Department and other stakeholders have worked throughout this rulemaking to clarify and refine section 20.2.50.115 NMAC in several ways, as documented in NMED and NMOGA's final redline. NMOGA asks that the Board adopt these critical changes. [See alternative proposed NMOGA SOR 77-78.]

<u>Oxy proposes to change three years to five years in E(1)(b):</u>

…."For sites that already have a VRU installed as of the effective date of this Part, the owner or operator shall install backup control devices or redundant VRUs within ~~three~~ <u>five</u> years of the effective date of this Part."

<u>Oxy:</u> Under 20.2.50.115.E(1)(b) NMAC, sites that already have a VRU installed as of the effective date of the rule are required to install a backup control device or redundant VRU. Although the Department's January 18, 2022 proposal incorporates a three-year phase-in schedule, Oxy USA continues to believe that a five-year phase-in timeline is more appropriate. Parties on all sides of the proceeding, including members of the Board, acknowledged during the hearing that the new equipment and retrofits required by these rules are substantial. As Mr. Holderman noted in his testimony, steel shortages, component shortages, lack of skilled manufacturing labor, limited manufacturing

capacity, lack of skilled installers, supply chain issues, and growing demand for similar equipment in New Mexico and other states all limit operators' abilities to meet the proposed rule's retrofit and installation requirements within the proposed three-year timeframe. Hearing Transcript at TR-1897:5-11.

When discussing storage vessel requirements, NMED's Elizabeth Bisbey-Kuehn acknowledged that there will be supply chain issues, competition among manufacturers, and "… real construction and logistical challenges to, I think, even probably having that infrastructure -- that infrastructure available to comply with these requirements." Hearing Transcript at TR-2894:4-23. These concerns also apply to the installation of VRUs. As Mr. Holderman's testimony noted, control device manufacturers estimate that the market as a whole can produce up to 500 VRUs in a year, which is not enough to meet the substantial increase in demand triggered by the rule. Oxy USA alone would need approximately 150 to 200 backup VRUs for the 2,700 wells it operates in the state. That does not include any primary VRUs that Oxy USA will need for normal operations. Hearing Transcript at TR-1898:21-25.

In addition, Oxy USA would not be the only operator affected by the requirements of 20.2.50.115 NMAC. Every other operator impacted by this rule would also need to begin obtaining VRUs and other control devices in order to comply. This means that the 500 total VRUs available to the market each year would be split between new facilities, existing facilities without a primary VRU, and existing facilities without a backup VRU. Splitting the limited resources among these facilities will likely prevent some facilities from obtaining a primary VRU, let alone a backup. However, facilities without a primary VRU have greater emissions – and a greater potential for emissions reductions – than those that only lack a backup VRU. Oxy USA's proposed five-year timeline would allow sufficient time for these facilities to obtain and install primary VRUs, before triggering the demand for backup VRUs.

Finally, even if the VRU supply were eventually able to meet demand, operators would still need skilled personnel to install and maintain the equipment. It could take years for manufacturing capacity and the labor force to scale to the necessary levels. Oxy USA believes it is critical to provide additional phase-in time that accounts for the realities of these resource restrictions and allows operators to target higher-emitting sources first. Without meaningful additional relief on the deadline for VRU installation, Oxy USA and other operators run the risk of being out of compliance for reasons that are completely beyond their control.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with the requirements of this Part.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event, including the name of the person(s) conducting the inspection, any maintenance or repair activities required, and the date and time stamp(s), including GPS of the location, of any monitoring event. The owner or operator shall record the type of redundant control device used during VRU downtime, or keep records of the source shut down and isolated and the time period during which it was shut down, or records of compliance with an air permit issued prior to the effective date of this Part.

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

<u>NMED:</u> Subsection E of Section 20.2.50.115 sets forth requirements for vapor recovery units. All VRUs must be operated as a closed vent system that captures and routes VOC emissions back to the process or to a sales pipeline. Venting to the atmosphere is prohibited and a backup control device (e.g. flare, ECD,TO) or a redundant VRU is required during periods of startup, shutdown, maintenance, or other downtime such as malfunctions. Based on a proposal by Oxy USA, the Department added a provision allowing a three-year time frame for installation of redundant controls at locations that already have VRUs to accommodate supply chain issues. NMED Rebuttal Ex. 1, p. 56.

Based on proposals by NMOGA, the Department added provisions that authorizes an exemption from the requirement to install a redundant VRU if approved in a state permit, and to authorize owners and operators to shut down and isolate the source being controlled by a VRU in lieu of using a backup VRU during the startup, shutdown, or maintenance of the primary VRU. *Id.* at 55. Owners and operators of VRUs must comply with the monitoring requirements for equipment leaks as specified in Section 20.2.50.116, or implement a program that meets the requirements of NSPS Subpart

OOOOa. NMED Exhibit 32, p. 77.

For each VRU inspection or monitoring event, the owner or operator must record the result of the event, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator must also record the type of redundant control device used during VRU downtime. Inspections and monitoring events must be date and time stamped in accordance with the requirements of Part 50. *Id.*

Owners and operators of VRUs are required to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 78-79 and NMED Rebuttal Exhibit 1, pp. 55-56. [NMOGA's earlier proposals to change to the title of this subsection and to remove the requirements to record information related to the inspection and monitoring of VRUs are not part of its final proposal.]

<u>NMOGA would delete paragraph (4):</u> This language appears in Subsection G.

F. Recordkeeping requirements: In addition to the general recordkeeping requirements of 20.2.50.112 NMAC, 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 assessment, where applicable, and as required by this Part; and

(2) the information required in Paragraph (6) of Subsection B of 20.2.50.115 NMAC.

<u>NMED:</u> Subsection F of Section 20.2.50.115 sets forth recordkeeping requirements for all control devices. Owners and operators must maintain records of a certification of the closed vent system assessment if applicable, and the information required in Paragraph (6) of Subsection B. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 75-79.

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]

NMED: Subsection G of Section 20.2.50.115 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 75-79.

Estimated Emissions Reductions and Costs Resulting from Section 20.2.50.115

There are no emissions reductions from control devices themselves; rather, control devices are used to reduce emissions associated with the equipment and processes addressed in Part 50. The estimated reductions are therefore discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Likewise, the estimated annualized costs of the VOC and NOx emissions reductions resulting from implementation of Part 50 are discussed in the testimony regarding the proposed requirements for the specific equipment and processes addressed in Part 50. Details on the emissions, costs, and reductions are found in the 'Reductions and Costs' spreadsheets for each of the various equipment and process categories regulated under the proposed rule. These costs are specific to the particular equipment/process and the pollutant being controlled. NMED Exhibit 32, p. 79.

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

NMED: **Description of Equipment or Process**

The processing of natural gas includes the removal of natural gas liquids from field gas and/or the fractionation of mixed liquids to natural gas products. There are a number of potential sources of equipment leaks during production and processing, such as pumps, pressure relief devices, valves, flanges, and other connectors that have a leak potential due to seal failure. In addition, leaks can occur from open-ended lines and valves as well as from corrosion of welded connections, flanges, and valves. The large number of valves, pumps, and other equipment associated with natural gas production and processing can be a significant sources of VOC emissions.

There are also a number of potential sources of fugitive emissions throughout the oil and gas sector. These can occur from poorly fitted connection points or deterioration of seals and gaskets. Fugitive emissions can also be caused by changes in pressure, temperature, or mechanical stresses. A "fugitive emissions component" may be defined as any component that has the potential to emit fugitive emissions at any of the sources previously identified, including valves; connectors; pressure relief devices; open-ended lines; access doors; flanges; closed vent systems; thief hatches or other openings on storage vessels; agitator seals; distance pieces; crankcase vents; blowdown vents; pump seals or diaphragms; compressors; separators; pressure vessels; dehydrators; heaters; instruments; and meters. Devices that would naturally vent as part of normal operations, such as natural gas-driven pneumatic controllers or pumps, are not included as fugitive emissions components. NMED Exhibit 32, p. 80; NMED Exhibit 34.

Control Options

Emissions from fugitive emission sources such as leaking valves, connectors, and flanges can be controlled through implementation of an emission leak detection and repair (LDAR) program. In simple terms, LDAR programs reduce emissions by requiring owners and operators to inspect their facilities to find and repair leaks. Leak detection methods include:

- Audio, visual, and olfactory (AVO) inspections;
- Instrument monitoring according to EPA Reference Method 21, 40 C.F.R. Part 60, Appendix A-7 ("EPA Method 21"); and
- Monitoring using optical gas imaging (OGI).

AVO inspections rely on the use of sight, sound, and smell to identify leaking components by listening for hissing or unusual sounds coming from equipment (audio); looking for cracks, holes, visible liquids leaks, or staining (visual); and smelling for unusual or strong odors (olfactory).

EPA Method 21 is an established reference method that identifies leaks using a portable instrument that can detect the presence of organic gases and measure their volumetric concentration in parts per million (ppm). The method also allows for the use of a soap solution applied to components that will form bubbles if there is a leak present. OGI is a newer method for leak detection that utilizes forward-looking infrared (FLIR) cameras to conduct inspections of equipment components to identify leaks. OGI infrared cameras are highly specialized thermal cameras that can identify methane using its infrared absorption characteristics. OGI cameras can be used to survey large numbers of components in a short amount of time, whereas EPA Method 21 inspections require inspecting one component at a time with the instrument probe.

When using EPA Method 21, a leak is detected whenever the measured concentration exceeds the defined concentration threshold standard. In Subparagraph (c) of Paragraph (4) of Subsection C of Section 20.2.50.116, this is specified as 500 ppm. When using OGI, a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation.

The control effectiveness of an LDAR program is based on the frequency of monitoring and the leak definition. More frequent monitoring means that leaks are detected and repaired sooner, so that they emit for a shorter time period, and possibly while they are still small and before they grow larger. A lower ppm leak definition will mean that a larger number of leaks must be repaired than with a higher ppm definition. NMED Exhibit 32, pp. 80-82.

Rule Language

The requirements in Section 20.2.50.116 are based on similar rules for LDAR programs for oil and gas sources adopted by Colorado and Pennsylvania, and in NSPS Subparts OOOO and OOOOa, as described in detail in NMED Exhibit 32, pp. 84-86.

A. Applicability: Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Components in water or air service are not subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility-wide PTE and in determining the monitoring frequency requirements of this Section.

<u>NMED:</u> Subsection A of Section 20.2.50.116 lists the facilities to which this Section applies. The requirements of Section 20.2.50.116 apply to well sites, tank batteries, gathering and boosting stations, natural gas processing plants, transmission compressor stations, and associated piping and components. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at well sites, tank batteries, gathering and boosting stations, natural 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. Tank batteries supporting multiple facilities are subject to the requirements for the most stringently regulated facility of which they are

a part.

<u>NMED:</u> Subsection B of Section 20.2.50.116 requires owners and operators to perform the monitoring, recordkeeping and reporting activities specified in Subsections C through G. The Department and NMOGA agreed to add a provision addressing tank batteries based on the inclusion of a new definition for that term. *See* Tr. Vol. 4, 1110:2-7, 1121:15-17The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, and Tr. Vol. 4, 1110:2-7, 1121:15-17.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements:

(1) The owner or operator of a facility with an annual average daily production or average daily throughput of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct an external 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 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; and

(d) any positive detection during the AVO inspection shall be repaired in accordance with Subsection E if not repaired at the time of discovery.

<u>NMED:</u> Paragraph (1) of Subsection C of Section 20.2.50.116 sets forth default monitoring requirements for owners and operators of facilities with an annual average daily production greater than 10 barrels of oil (bbls) per day, or an average daily production greater than 60,000 standard cubic feet per day of natural gas. Owners and operators of these facilities are required to inspect 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 using AVO leak detection method at least weekly. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

[NMOGA and Kinder Morgan's earlier edits in this paragraph are not part of their final proposal.] The frequencies for AVO inspections proposed by NMED are critical to ensuring that the sources are maintained in good working order, operating as intended, and are not causing excess emissions. Liquids from facilities that are primarily oil producing facilities can still be sources of VOC emissions. The existing provisions require reasonable and appropriate AVO inspections to supplement the required LDAR requirements, which occur on a less frequent basis. See NMED Rebuttal Ex. 1, p. 58.

GCA: The GCA supports the NMED's proposed requirements relating to the tagging and repair of leaks detected during an AVO inspection in 20.2.50.116(C)(1)(d) and 20.2.50.116(E). The requirement in the July 2021 draft rule that a leaking component discovered through an AVO inspection be tagged within three calendar days presented significant challenges for GCA companies responsible for providing gas compression services; the sites are often quite remote and are manned most frequently by the customers' personnel. GCA Ex. 15 (Copeland Direct) at 22-23. The proposed rule retains the obligation to tag and repair leaking components found through AVO inspection, but eliminates the three-day deadline for affixing a visible tag to the leaking component. [See GCA Closing Argument pp. 18-19, SOR 54-57 for more of Mr. Copeland's testimony.]

(2) The owner or operator of a facility with an annual average daily production or average daily throughput of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an external 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 defects and leaking components as specified in Subparagraphs (a) through (d) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

NMED: Paragraph (2) of Subsection C of Section 20.2.50.116 sets forth default monitoring requirements for owners and operators of facilities with an annual average daily production equal to or less than 10 bbls per day, or an average daily production equal to or less than 60,000 standard cubic feet per day of natural gas. Owners and operators of these facilities are required to inspect 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 using AVO leak detection method at least monthly. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

<u>NMOGA:</u> If the EIB determines that proximity LDAR, discussed below, is within its statutory authority, then NMOGA's weekly AVO language could be inserted here: **"except that an owner or operator of a well site within 1,000 feet (as measured from the center of the well site to the applicable structure or area of public assembly) of an occupied area shall conduct the AVO inspection at least weekly."**

(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, and upon request by the department for good cause shown:

(a) for existing well sites and standalone tank batteries, the owner or operator shall comply with these requirements no later than two years from the effective date of this Part.

<u>NMOGA would revise paragraph (a):</u>

(a) for existing well sites, <u>inactive well sites</u>, <u>standalone</u> tank batteries, <u>gathering and boosting stations, natural gas processing plants, and transmission compressor stations</u>, the owner or operator shall comply with these requirements within two years of the effective date of this Part.

NMOGA states that the words are inserted to prevent conflicts in effective dates between facility types for tank batteries associated with another facility type; and there needs to be an implementation date for these other facilities.

(b) for well sites and standalone tank batteries:

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

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

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

(c) for gathering and boosting stations and natural gas processing plants:

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

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

NMED: Paragraph (3) of Subsection C of Section 20.2.50.116 requires owners and operators of the following facilities to perform inspections using EPA Method 21 OGI according to the schedules outlined below.

Subparagraphs (a), (b) and (c)

For wellhead sites and standalone tank batteries, owners and operators must conduct inspections annually at facilities with a PTE less than two tpy VOC; semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and quarterly at facilities with a PTE equal to or greater than five tpy VOC. For gathering and boosting stations and gas processing plants, owners and operators must conduct inspections quarterly at facilities with a PTE less than 25 tpy VOC; and monthly at facilities with a PTE equal to or greater than 25 tpy VOC. The Department is also proposing an extended compliance period of two years from the effective date of Part 50 for existing wellhead sites and tank batteries, in response to comments raised by Oxy USA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 80-83, 84-90. In further support of this proposal, the Department refers the Board to the testimony of EDF witnesses Dr. David Lyon (EDF Exhibits RR and XXa, and Tr. Vol. 2537:15 – 2581:18) and Hillary Hull (EDF Exhibits FF and JJJ, and Tr. Vol. 8, 2591:9 – 2635:3).

NMOGA proposes less frequent surveys at higher emission thresholds for well sites and tank batteries. In support of this proposal, NMOGA cited data submitted to EPA by the API in their December 17, 2018 comments on the EPA’s October 15, 2018 proposed reconsideration of the Oil and Gas Sector NSPS, based on two years of NSPS Subpart OOOOa leak surveys. The Board should find that these data should not be used to justify less frequent surveys and higher emissions thresholds. NSPS Subpart OOOOa applies to facilities for which construction, modification, or reconstruction commenced after September 18, 2015. Therefore, facilities subject to NSPS Subpart OOOOa were still no more than three years old at the time those NSPS Subpart OOOOa surveys were completed. The Board should find that those results cannot be considered representative of the existing facilities that will be covered by the requirements of Proposed Part 50, some of which are several decades old. For example, according the NMED Equipment Data the average age of a storage tank in New Mexico is over 10 years old. It is important to note that standards for "new" sources, as defined in NSPS regulations and proposed Part 50, are intended to apply to sources constructed or reconstructed after a certain date into the foreseeable feature, even after those sources would no longer be considered new in the general sense of that term. NMED Rebuttal Exhibit 1, pp. 63-64.

NMOGA also cited to a recently published peer reviewed research study of upstream leak frequencies to support less frequent surveys at higher emission thresholds. *See* NMOGA Appendix B at p. 32, citing to "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." The Board cannot properly rely on this study because NMOGA did not provide a detailed comparison of the results of that study to the frequency or emission rates that were the basis of the 2016 CTG estimates of cost effectiveness. NMED Rebuttal Exhibit 1, p. 64.

NMOGA also cited a recent paper commissioned by the U.S. Department of Energy and led by Colorado State University and noted that 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. Based on this assertion, NMOGA concluded that "less potential for equipment leaks translates to less reductions from a leak detection and repair program." *See* NMOGA Appendix B at p. 32. However, NMOGA failed to note the findings of the study that "the study indicates that study emission factors ***either agree with, or are larger than***, current greenhouse gas reporting program (GHGRP) emission factors for the western U.S." (Emphasis added). NMOGA did not provide any details regarding how the results of the second paper were used to adjust the VOC reduction estimates from those in the 2016 CTG to those in NMOGA's testimony, or how they were used to adjust the cost per ton of VOC reduced. For example, NMOGA relied on the fact that the recent studies have found fewer components and lower leak frequencies in their surveys, and then uses that information in reducing the estimated VOC emission reductions. However, there was no discussion of how the same information would affect the costs of an LDAR program (e.g., fewer components and fewer leaks to repair should also lead to lower costs). The NMOGA analysis also did not take into account the estimated leak rates (in standard cubic feet per hour), including the presence of large emitters relative to those that were the basis of the 2016 CTG estimates. *See* NMOGA Exhibit 7 at page 47. The Board should therefore find that it cannot properly rely on the cited study to support less frequent surveys at higher emission thresholds. NMED Rebuttal Exhibit 1, p. 65.

NMED reviewed the two cited papers and agreed that they present useful data on leak frequencies and emission rates. However, other commenters also submitted peer reviewed studies showing that fugitive emissions from oil and gas production may be higher than previously estimated. *See, e.g.*, Environmental Defense Fund ("EDF") Exhibits C, D, E, F, H, I, and J. The Board should find that it is beyond the scope of this rulemaking to conduct a comprehensive literature review of all the recent relevant research on fugitive emissions and establish new cost effectiveness values for LDAR programs specific to the different basins in New Mexico. NMOGA's testimony and comments do not present sufficient data or explanation for Board to determine whether the cost effectiveness values presented in NMOGA Appendix B are based on an analysis that accounts for all of the variables that would actually determine the cost effectiveness of a specific LDAR program. NMED Rebuttal Exhibit 1, pp. 65-66.

NMOGA further argued that the incremental VOC reductions and the cost effectiveness of the proposed LDAR requirements for gas processing plants were not properly calculated, citing the fact that the 2016 CTG cost per ton of VOC was used even though the proposed requirements in Section 20.2.50.116 go beyond the requirements of the 2016 CTG and NSPS Subparts OOOO and OOOOa. NMOGA proposed changes that would allow compliance with NSPS Subpart OOOO or OOOOa, as revised, to satisfy the requirements of Section 20.2.50.116, and that would decrease the frequency of monitoring at those gas processing plants not subject to NSPS Subpart OOOO or OOOOa from quarterly to semiannually for plants with a PTE of VOC less than 25 tpy VOC, and from monthly to quarterly for those with a PTE equal to or greater than 25 tpy VOC.

The Board should reject NMOGA's proposal and find that it is not appropriate to allow compliance with the LDAR requirements in NSPS subparts OOOO or OOOOa ***as revised*** to constitute compliance with Section 20.2.50.116. One of the central purposes of proposed Part 50 is to provide state-level regulations that are not subject to the changes that occur at the federal level. Adopting NMOGA's proposal would give New Mexico no certainty over the future regulatory requirements limiting VOC emissions from equipment leaks at oil and gas facilities in the State. Notably, NSPS subpart OOOOa was promulgated in 2016 under the Obama administration, then both NSPS Subparts OOOO and OOOOa were substantially amended in 2020 during the Trump administration, and the 2020 amendments were then disapproved in June 2021 under the Congressional Review Act following the 2020 election. In addition, the NSPS, although it requires monthly checks of pumps and valves at gas processing plants, allows for extended periods of time between checks of connectors, depending on the percent of connectors that are found leaking at any one facility. *See* NMED Rebuttal Exhibit 1, p. 66.

<u>NMOGA proposes changes in paragraphs (b) and (c):</u>

(b) for well sites and standalone tank batteries:

(ii) annually at facilities with a PTE less than ~~two~~ ten tpy VOC;

(iii) semi-annually at facilities with a PTE equal to or greater than t~~wo~~ <u>ten</u> tpy and less than <u>twenty</u>-five tpy VOC; and

(iv) quarterly at facilities with a PTE equal to or greater than <u>twenty</u>-five tpy VOC.

(c) for gathering and boosting stations and natural gas processing plants:

(i) ~~quarterly~~ <u>semiannually</u> at facilities with a PTE less than 25 tpy VOC; and

(ii) ~~monthly~~ <u>quarterly</u> at facilities with a PTE equal to or greater than 25 tpy VOC.

<u>NMOGA:</u> See the testimony of John Smitherman, NMOGA Exhibit A1, p. 23:16-24:40; NMOGA Exhibit 58; Tr. 8:2668 ff. The Board should reject the more stringent LDAR thresholds and frequencies proposed by NMED and adopt NMOGA's proposal because the added stringency of NMED's proposal has minimal impacts on VOC reductions and fails to account for the diminishing returns of increased survey frequency. The record reflects that VOC emissions reductions are not very effective at reducing ozone in New Mexico. The Board must give due consideration to the "character and degree of injury to or interference with health, welfare, visibility and property." NMSA 1978, § 74-2-5. This means the Board must consider the harm at issue and develop rules that are responsive to that harm. By requiring the Board to consider character and degree of injury, the legislature seeks to establish a fit between the problem and solution. For example, if the character of injury is such that only certain types of measures will redress that injury, the

statute implicitly directs the Board to only adopt those standards that are responsive.

While New Mexico needs strong measures to address ozone, the weight of evidence fails to support the proposition that reducing VOC emissions through measures such as LDAR will redress that injury. The areas of New Mexico impacted by this rule are NOx sensitive, meaning that VOC emissions reductions have a relatively lesser impact on ozone concentrations, particularly in the quantities attributable to anthropogenic sources, such as oil and gas. As Mr. McNally testified, “additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.” NMOGA Exhibit A4, at 16. Based on the limited efficacy of VOC controls, it makes little sense to adopt some of the most stringent statewide leak detection and repair standards in the country when those standards will do little to help the state combat its ozone challenges.

While NMOGA supports a strong LDAR program as a matter of good policy, NMOGA does not believe the onerous proposals advanced by NMED are warranted given the limited impact VOC emissions reductions are anticipated to have on ozone concentrations. Adopting these proposals would reflect inadequate consideration of the “degree and character” of the injury and the ability of these standards to redress that injury. In addition to considering the character and degree of injury, the Board also must consider the “technical practicability and economic reasonableness of reducing or eliminating air contaminants from the sources involved.” NMSA 1978, § 74-2-5. This mandatory consideration reflects the legislature’s assessment that not all possible emissions reductions are worth pursuing: where there are technical or economic challenges that outweigh the benefits of implementing the proposed standards, based on the weight of evidence, such standards should not be adopted. Based on this consideration, the Board should reject the excessive leak frequencies proposed by the department because they impose unreasonable costs on the oil and gas industry and provide little emissions benefit. The competing proposals are as follows:

	Well Sites & Standalone Tank Batteries		Gathering and Boosting Stations, Gas Plants, and Transmission Compressor Stations	
Frequency	**NMED**	**NMOGA**	**NMED**	**NMOGA**
Annually	<2 TPY	<10 TPY	None	None
Semiannually	=>2 to <5 TPY	=>10 to <25 TPY	None	<25 TPY
Quarterly	=>5 TPY or more	=>25 TPY or more	<25 TPY	=>25 TPY
Monthly	None	None	=>25 TPY	None

As is clear from these proposals, although NMOGA is not aligned with the department, NMOGA has nevertheless proposed an aggressive leak detection program. NMOGA's proposal ultimately strikes a more appropriate balance. Mr. Smitherman's testimony makes clear that most leaks are identified and repaired during initial surveys. NMED's own data demonstrates that 40% of all emissions reductions from LDAR are achieved with annual surveys, 60% are achieved with semiannual surveys, and 80% are achieved with quarterly surveys. *See* NMOGA Exhibit 58, at 14. A study from the American Petroleum Institute consisting of 6,000 surveys across 3,482 sites also found less than 2 leaks per site during initial surveys, with the leak rate falling quickly to less than 1 leaking component on average in subsequent surveys.

Although the quantity of leaks detected diminish with increased frequency, the per-survey cost of conducting LDAR remains relatively the same, meaning that less emissions per dollar are reduced with each additional survey. NMOGA's technical testimony demonstrates the exorbitant incremental costs associated with increasing LDAR frequency. The following tables summarize the costs of transitioning from annual to semiannual (NMOGA Exhibit 58, at 46), annual to quarterly (NMOGA Exhibit 58, at 47), and semiannual to quarterly (NMOGA Exhibit 58, at 48) at well sites.

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Annual to Quarterly	Incremental VOC Reductions (tpy)	Incremental Annual Cost (2019)	Incremental Cost per Ton
NG Well Site	0.509	$3,016	$5,923
Oil Well Site (GOR < 300)	0.096	$3,016	$31,553
Oil Well Site (GOR >= 300)	0.122	$3,016	$24,681

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Annual to Semiannual	Incremental VOC Reductions (tpy)	Incremental Annual Cost (2019)	Incremental Cost per Ton
NG Well Site	0.255	$ 1,005	$3,947
Oil Well Site (GOR < 300)	0.048	$ 1,005	$21,028
Oil Well Site (GOR > 300)	0.061	$ 1,005	$16,448

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Semiannual to Quarterly	Incremental VOC Reductions (tpy)	Incremental Annual Cost (2019)	Incremental Cost per Ton
NG Well Site	0.255	$ 2,011	$7,899
Oil Well Site (GOR < 300)	0.048	$ 2,011	$42,078
Oil Well Site (GOR > 300)	0.061	$ 2,011	$32,913

The following table illustrates the incremental costs of increased LDAR monitoring at gathering and boosting sites (NMOGA Exhibit 58, at 50):

Incremental Cost per Ton of VOC Reduction			
	ERG Costs & Reductions	NMOGA Costs & Reductions	
	New Mexico	San Juan	Permian
Annual to Semiannual	$3,068	$17,154	$6,905.55
Semiannual to Quarterly	$6,136	$34,313	$13,813.14
Annual to Monthly	$9,586	$80,303	$32,326.67
Semiannual to Monthly	$13,940	$122,402	$49,274.08
Quarterly to Monthly	$29,627	$298,580	$120,195.96

As this analysis demonstrates, increasing LDAR frequency achieves minimal emissions reductions relative to the costs incurred. For well sites, NMOGA's analysis uses NMED's own data, except that NMOGA has used a different model plant. As discussed in Mr. Smitherman's testimony, a model plant is a statistically average facility commonly used in rulemaking efforts to quantify costs and emissions reductions associated with a proposal. In the leak detection context, the goal of a model plant is to estimate the average population of potentially leaking components at a given facility type. Roughly speaking, constructing a model plant involves gathering data on the number of potentially leaking equipment and components at facilities to derive an average component count. An emissions estimate is then derived by multiplying the component count by the leaking component emissions factor.

While NMED relied on well site model plant data from 1996 based on equipment surveys conducted outside of New Mexico, NMOGA relied on a model plant derived from data gathered from New Mexico oil and gas operators in 2019. NMOGA's more recent and geographically relevant data came from EPA's 2019 GHG report and showed that, on average, New Mexico sites have fewer pieces of equipment per site, fewer components per piece of equipment, and lower potential leak emissions than was observed in the 1996 study NMED has relied upon. Unlike adjustments to the well site model plant, NMOGA's incremental analysis for well sites does not alter the cost data NMED relied upon, even though there is ample evidence in the record to suggest that NMED has underestimated such costs. Similarly, while NMED relied on gathering and boosting station model plant data derived from a 1995 EPA/GRI study, NMOGA relied on a 2019 Colorado State University study, which showed fewer equipment, fewer components, and lower potential leak emissions relative to NMED's data. NMOGA Exhibit 28.

Several parties fought hard to keep NMOGA's incremental LDAR analysis from being admitted into evidence. Nevertheless, since the incremental LDAR analysis has been admitted, its substantive conclusions have largely gone unrefuted. On rebuttal, NMED argued it could not evaluate the model plants because it did not understand how they were constructed. On surrebuttal, NMOGA countered that it provided the model plant data, and NMOGA applied the same methodology to construct its model plant that EPA applied in constructing the model plant upon which NMED relied. On surrebuttal, Mr. Palmer testified that the CTG does not direct states to conduct an incremental cost analysis, implying that such a review is not appropriate. Tr. 8:2778:18-20. But Mr. Palmer does not take issue with the methodology or mathematical conclusions reached by Mr. Smitherman. And the fact that the CTG does not recommend an incremental cost analysis is of no consequence. The CTG is guidance and has no bearing on the factors the Board must consider in fulfilling its statutory duty under state law. The Board is obligated to consider the "economic reasonableness" of the proposals put before it. NMOGA's uncontroverted incremental analysis establishes that the Department's LDAR proposal is not economically reasonable and should not be adopted. This does not mean that NMOGA believes that no LDAR requirements should be adopted. Instead, NMOGA believes that the frequencies and thresholds it has provided in its comments represent a more reasonable way of attaining VOC reductions at a less exorbitant cost.

<u>CEP opposes NMOGA's proposal:</u> The EIB should reject attempts to weaken the Department's proposal by requiring less frequent inspections at well sites and compressor stations. NMED's proposed LDAR inspection requirements are necessary to ensure that operators find and fix leaking equipment promptly.

Dr. Lyon testified that the Permian Basin is very leaky. 8 Tr. 2542:5-2547:21. Direct measurement studies conducted in the Permian Basin between 2020 and 2021 demonstrate a leak rate of approximately 3%, which means that oil and gas operators in the Permian Basin leak 3% of the natural gas they produce. This is a higher leak rate than the national average estimated by EDF. 8 Tr. 2549:16-25. According to Dr. Lyon, "The Permian has some of the highest emissions encountered in -- in the US . . . ." 8 Tr. 2548:5-7. Measurements taken in 2018 at well pads in the New Mexico Permian Basin found high emissions that were "five to nine times higher than estimates based on the EPA National Emissions Inventory and about 10 times higher than based on the Greenhouse Gas Reporting Program." 8 Tr. 2544:17-21. EDF Ex. XX at 8.

Frequent inspections, using modern leak detection instruments, are necessary to identify leaks such as those commonly found in the Permian Basin. 8 Tr. 2541:1-3, 2546:9-12; EDF Ex. XX at 8. There are several lines of evidence that support frequent inspections as proposed by NMED. First, studies conducted in the Permian Basin as well as other U.S. and international oil and gas basins demonstrate that leaks are intermittent. 8 Tr. 2546:8-12, -2579:10-11; EDF Ex. XX at 7. As Dr. Lyon described: "super-emitters often are intermittent and may occur for a day or hours or even minutes, and -- and they can occur at all sites. So it's critical that sites are inspected to really find these super-emitting sites." 8 Tr. 2548:22-25, -2549:1; EDF Ex. XX at 10. Second, a single large leak or "super-emitter" can release hundreds of tons of pollution to the atmosphere. Super emitters are quite prevalent in the Permian Basin. A recent study using satellites detected over 37 very large leaks in the Permian that each had the potential to release over 4,000 tons per year of methane if left unabated for one year. 8 Tr. 2545:18-22. Another study conducted in August 2021 detected over 900 methane plumes from 500 sources that also could have emitted 200 tons per year of methane if left unabated for one year. 8 Tr. 2546:1-3. Because a single leak can be responsible for hundreds of tons of pollution, according to Dr. Lyon "using the number of leaks is an inappropriate way of estimating emissions or the efficacy of LDAR, I think particularly because it's really the magnitude of the emissions rather than the number of leaks." 8 Tr. 2549:6-10. Third, leaks can re-occur at the same site over time. Many large plumes detected in 2021 at sources in the Permian Basin had also been detected previously at the same sources in 2019. 8 Tr. 2546:4-7. Fourth, frequent inspections can not only detect and help mitigate leaks and super emitters, they can also help operators optimize their operations. 8 Tr. 2586:6-17, -2587:7-15; 10 Tr. 3224:5-18. A number of studies show that poorly maintained or operated equipment or operations can lead to leaks and super emitters. 8 Tr. 2555:1-13.

One of the major sources of super emitters in the Permian and elsewhere are controlled storage tanks that are venting to the atmosphere due to some kind of equipment malfunction. EDF Ex. RR, 4. Another example is a malfunctioning pneumatic controller. 7 Tr. 2225:12 to 7 Tr. 2227:14.

Frequent instrument-based inspections can help an operator identify malfunctioning equipment and other problems that can leak significant amounts of VOCs and methane to the atmosphere. According to Dr. Lyon, LDAR can help both “looking for equipment leaks, but also looking for underlying problems, including maintenance issues that could lead to future emissions.” 8 Tr. 2586:8-12, -2588:9-16. Frequent inspections as proposed by the Department are necessary to identify stochastic and heterogeneous leaks from poorly operating or maintained equipment and operations, some of which can release hundreds of tons of pollution to the atmosphere per leak, while also helping operators optimize their operations.

AVO inspections are not a substitute for instrument-based inspections. Frequent inspections are only valuable if the methods operators use to look for leaks are reliable. The Department’s proposed instrument-based inspections are essential to identifying leaks, including large leaks or super-emitters, as sensory-based AVO inspections do not reliably detect leaks. 8 Tr. 2559:8-15, -2575:14-15; 10 Tr. 3223:15-3224:3, -3225:6-25. AVO inspections are “highly dependent on both the kind of skill and attention of the operator and the conditions in the environment, including things like the wind . . . .” 8 Tr. 2559:10-13; 10 Tr. 3223:19-23. AVO inspections are also flawed because of a lack of verification. According to Mr. Alexander, “. . . there's no way to really document or verify AVO inspections other than just to take one's word for it and fill out a piece of paper, whereas routine OGI inspections are verifiable, and the evidence is physical and can be documented.” 10 Tr. 3223:24-3224:3. Dr. Lyon testified that AVO cannot reliably detect emissions from malfunctioning pneumatic controllers, 7 Tr. 2228:6-16, or from large emitters such as unlit flares due to the height of the flares. 8 Tr. 2575:14-15.

Low-producing wells can be significant emitters and must be inspected at least annually, as proposed by NMED. The scientific studies, including one conducted in the New Mexico Permian in 2018, show a weak relationship between well pad emissions and production. These studies demonstrate that low-producing wells can emit substantial amounts of VOC emissions, sometimes in excess of the potential to emit, due to malfunctions that cause abnormally high emissions. 8 Tr. 2540:18-2541:3. Frequent inspections with instruments such as optical gas imaging cameras are necessary to mitigate emissions from these low-producing wells. 8 Tr. 2540:18-2541:3.

Dr. Lyon described three separate studies that identified significant leaks from low-producing wells. The first, the 2020 Robertson et al. study, found that wells with production below 10 barrels of oil equivalent per day (BOE/d) had similar emissions as non-marginal wells, based on a comparison of absolute methane emissions and gas production by site. The second study, conducted in 2020 by Deighton et al., found that marginal wells are a disproportionate source of methane and VOCs relative to oil and gas production. The third study, conducted by Omara et al. in 2018, found that low natural gas production sites accounted for 85% of the total number of sites in the study yet were responsible for nearly two-thirds (63%) of the total methane emissions. 8 Tr. 2554:10-25. Many studies identify poor maintenance as a driver of observed methane leakage at marginal sites. These avoidable methane emissions typically are not well represented in traditional emission factor calculations and contribute to the large differences that have often been observed between inventory-based estimates and measurement studies. 8 Tr. 2555:9-18. These studies demonstrate that low production wells are likely a disproportionately large source of oil and gas methane emissions nationally. Mitigating the methane emitted from these sites could reduce a significant proportion of oil and gas methane emissions nationally. 8 Tr. 2555:19-24. Inspecting low-producing wells is essential to curbing emissions from oil and gas facilities. 8 Tr. 2555:19-24.

The Department conservatively estimated the pollution reductions that can be achieved by its proposed LDAR provisions. EDF analysis, based on direct measurements of emissions taken from oil and gas sources in New Mexico as well as other U.S. basins, demonstrates that the proposed inspections will reduce significantly more pollution than ERG estimates. ERG estimated the Department's LDAR proposal would apply to approximately 24,000 well sites in New Mexico and would result in the reduction of 7,131 tons of VOCs per year. NMED Ex. 69; 8 Tr. 2551:3-6. This is a gross underestimate of the pollution from New Mexico well sites that can be reduced by frequent leak inspection and repair requirements based on recent direct measurement studies. EDF Ex. XX at 6-7; 8 Tr. 2551:6-11. A 2018 study conducted by Robertson et al. estimated annual average well pad emissions in the New Mexico Permian Basin are 37 tons methane per year. 8 Tr. 2551:12-15. Using New Mexico gas composition, EDF converted the per well site methane emissions to VOCs. 8 Tr. 2551:16-18. Using these calculations, EDF estimates the average well pad in the Permian emits approximately 11 tons of VOC per year. 8 Tr. 2551:16-18. EDF then applied this per-well VOC emission factor to the 24,000 well sites in New Mexico that are subject to NMED's proposal. This calculation indicates that the total unabated VOC emissions from New Mexico well sites is closer to 260,000 tons of VOCs per year. 8 Tr. 2551:18-20. This is a significantly higher estimate of emissions that can be abated by LDAR inspections than the 7,131 tons of VOCs estimated by ERG estimated.

Direct measurements of emissions from well sites in the Permian Basin indicate that the Department's proposed LDAR requirements underestimate actual emission reductions because ERG grossly underestimated the baseline emissions that can be abated by frequent instrument-based inspections. 8 Tr. 2552:20-25. Other studies conducted in the Permian Basin indicate that Robertson's estimate of well site emissions is actually low, further underscoring the cost effectiveness of the Department's proposed LDAR program. 8 Tr. 2551:21-25; 8 Tr. 2552:1-2. Dr. Lyon refuted NMOGA's assertions that ERG overestimated the reductions associated with the Department's proposed LDAR program. 8 Tr. 2552:12-18. NMOGA based its estimate of emissions reductions on estimates submitted by operators to the EPA pursuant to EPA's Greenhouse Gas Reporting Program. 8 Tr. 2552:3-11.

Direct measurement studies conducted by EDF in the Permian Basin as well as numerous other basins throughout the U.S. demonstrate that emission estimates consistently underestimate measured emissions by significant magnitudes. 8 Tr. 2542:4-8 Tr. 2547:21. A 2018 meta-analysis of the various direct measurement studies conducted by EDF and other scientists concluded that measured U.S. emissions are 70% higher than estimates generated by EPA. 8 Tr. 2549:17-25; 8 Tr. 2550:1. The available scientific studies refute NMOGA's claim that ERG overestimated emission reductions.

The Department's estimate of the costs and VOC reductions associated with proposed 20.2.50.116 are reasonable and, if anything, quite conservative. 8 Tr. 2605:24-

2606:4; EDF Ex. JJJ at 6. EDF reviewed ERG's LDAR Reductions and Costs VOC Spreadsheet, NMED Ex. 69. Using more recent inspection cost information than ERG, EDF estimates the per well site cost of conducting semi-annual inspections is $1,658 for semi-annual inspections. This is 30% lower than ERG's estimate. 8 Tr. 2602:13-14. EDF's cost estimate represents the full cost of implementing an LDAR program in-house, which includes LDAR set up costs, survey costs, repair costs, and recordkeeping and reporting costs. 8 Tr. 2602:9-14. ERG relied on site-level data taken from EPA's 2016 Control Techniques Guidelines (CTG) to estimate the costs of conducting annual, semi-annual, and quarterly inspections. 8 Tr. 2602:15-18. EPA assumed $1,318 for annual OGI, $2,285 for semi-annual OGI, and $4,220 for quarterly OGI -- using 2012 dollars. 8 Tr. 2602:18-20. ERG assumed the same costs as assumed by EPA in 2016, except that ERG scaled the costs for inflation using the Chemical Engineering Plant Cost Index from 2012 dollars to 2019 dollars. 8 Tr. 2602:21-24. This resulted in ERG estimates of $1,370 for annual OGI, $2,375 for semi-annual OGI, and $4,385 for quarterly OGI. 8 Tr. 2602:15-15; 8 Tr. 2603:1-4. ERG assumed all sites would conduct semi-annual inspections at an annual cost of $2,375. 8 Tr. 2603:1-4.

A comparison of LDAR compliance costs relied on by the Colorado Air Pollution Control Division for its tiered LDAR program in 2014 and ERG's analysis underscores the conservative nature of ERG's cost estimates. In 2014, Colorado adopted a similar inspection program to that proposed by NMED. 8 Tr. 2603:17-19. Colorado's program, like the Department's proposal, requires differing inspection frequencies based on a facility's emissions. 8 Tr. 2603:19-21. In 2014, Colorado estimated the average cost effectiveness of conducting instrument-based inspections at well sites to be $1,259 per ton for well production facilities. 8 Tr. 2603:22-25. This assumed a tiered program consisting of monthly, quarterly, annual, and once-in-a-lifetime inspections. 8 Tr. 2603:25-8 Tr. 2604:1. While the comparison is not exact, the two estimates indicate the Department's estimate is conservative. 8 Tr. 2604:5-7.

Information submitted by operators to EPA in compliance with EPA LDAR requirements further underscores the likelihood that ERG has overestimated costs. 8 Tr. 2604:8-16. Reports submitted by operators to EPA in 2018 demonstrate that the average time to conduct an LDAR survey is decreasing as the operators have been implementing state and federal LDAR programs. 8 Tr. 2604:8-22. In 2018, M.J. Bradley analyzed approximately 120 reports containing compliance data from LDAR surveys of 3,832 well sites conducted by operators in 2017 and 2018. Of the well sites surveyed, 3,202 contain information on survey time. 8 Tr. 2604:15-16. These reports indicate that average time to conduct an LDAR survey is decreasing as the operators have been implementing state and federal LDAR programs. 8 Tr. 2604:17-20. The reports reviewed by M.J. Bradley indicate an average LDAR inspection takes approximately 1.25 to 1.6 hours per well, including travel time. 8 Tr. 2604:8-22.

Information from a new study demonstrates that inspection times are likely to continue to decrease due to the emergence of even more efficient screening methods such as aerial surveys which operators can use to screen multiple facilities for leaks in a much shorter time frame than can be achieved using ground based OGI methods. 8 Tr. 2604:8-2605:5. The rapid growth in advance methane detection technologies such as aerial surveys is likely to continue to reduce inspection times and thus LDAR compliance costs. 8 Tr. 2604:23-8 Tr. 2605:18. The Department's proposal allows operators to obtain approval to use alternative equipment leak monitoring plans. It is likely many of these plans will rely on a combination of fixed censors, aerial surveys, and satellites. 8 Tr. 2605:18-23. In sum, recent data regarding actual inspection time and the emergence of more efficient LDAR inspection methods indicates that the Department's estimate of the costs associated with conducting ground based OGI or Method 21 vehicle inspections is quite conservative. 8 Tr. 2605:16-2606:4.

NMOGA's proposal would increase the emission thresholds triggering each LDAR tier fivefold compared to NMED's proposal and result in substantial pollution to the atmosphere that can be cost effectively mitigated. EDF Ex. JJJ at 4; 8 Tr. 2608:6-18. EDF's analysis shows that NMOGA's proposal would result in 23,000 additional tons of VOCs and 79,000 additional tons of methane left unabated annually. EDF Ex. JJJ at 4; 8 Tr. 2608:22-25. NMOGA has significantly over estimated compliance costs for NMED's proposed LDAR requirements. EDF Ex. JJJ at 3; 8 Tr. 2606:6-16. NMOGA's estimate of the costs of conducting inspections is magnitudes higher than estimates conducted by NMED as well as other regulators who have adopted LDAR provisions. NMOGA estimates a per well site inspection cost of $6,400. 8 Tr. 2606:23-24. This is 169% higher than NMED’s, 286% higher than EDF’s estimate, and 168% to 228% higher than EPA’s. EDF Ex. JJJ at 7-8. NMOGA bases this inspection cost, in part, on comments submitted to EPA by API in 2016. 8 Tr. 2606:16-19. EPA rejected the API costs, however, when it finalized its requirements to reduce ozone precursors from oil and gas sources in 2016. 8 Tr. 2607:2-4. Ms. Hull reviewed NMOGA and API’s comments and found that API’s reasoning was critically flawed and NMOGA’s reliance upon this information is misplaced. EDF Ex. JJJ at 7; 8 Tr. 2606:16-2607:9.

API presumed that all operators would create their own in-house LDAR survey program from scratch rather than employ third-party providers. 8 Tr. 2607:5-9. This assumption inflates the cost of implementing an LDAR program. 8 Tr. 2607:8-9. For small operators it is often more economical to hire a third-party contractor to conduct leak inspections than to purchase its own infrared camera and other equipment necessary to conduct inspections. 8 Tr. 2607:10-14. For example, when Colorado first adopted its LDAR program in 2014, it assumed that operators who have less than 500 wells would hire a third-party contractor to conduct LDAR as they would not be able to fully utilize an infrared camera. 8 Tr. 2607:15-19; EDF Ex. BB. API also used basin-level averages to imply that for each survey, an operator would travel approximately 340 miles roundtrip. Ms. Hull testified that this estimate appears "extraordinarily high." 8 Tr. 2607: 20-23; EDF Ex. JJJ, pp. 7-8. 8 Tr. 2607:25-2608:3. NMOGA provided no support for how, if at all, API's comments to EPA that were rejected by EPA, are applicable to this proceeding. The EIB should reject NMOGA's weaker LDAR proposal as well as its inflated cost estimates. [See CEP proposed SOR 249-302 for additional detail; see also CEP’s Closing Argument, pp. 34-40 and proposed SOR 325-357 on the lack of reliability of NMOGA’s cost analysis by Mr. Dunham.]

(d) for transmission compressor stations, quarterly or in compliance with the federal equipment leak and fugitive emissions monitoring requirements of New Source Performance Standards, 40 C.F.R. Part 60, as may be revised, so long as the federal equipment leak and fugitive emissions monitoring requirements are at least as stringent as the New Source Performance Standards OOOOa, 40 CFR Part 60, in existence as of the effective date of this Part.

<u>NMED:</u> For transmission compressor stations, pursuant to an agreement with Kinder

Morgan and EDF, the Department is proposing that the required inspections be done quarterly, or in compliance with the requirements of the federal NSPS so long as those requirements are at least as stringent as those in existence as of the effective date of Part 50. This provision is warranted because more frequent monitoring would not be cost effective due to the low VOC profile of transmission compressor stations. The Board should adopt this proposal for the reasons stated in Tr. Vol. 8, 2516:10 – 2519:12, 2444:14 – 2446:15.

<u>Kinder Morgan:</u> On September 24, 2021, Kinder Morgan and EDF filed a joint proposal for leak detection and repair (LDAR) at transmission compressor stations. Notice of Joint Proposal Regarding Sur-Rebuttal Testimony of Kinder Morgan and EDF (Sept. 24, 2021) ("Joint Proposal"). Under the Joint Proposal, transmission compressor stations, regardless of potential to emit, would be afforded two compliance options for the frequency of monitoring under Paragraph (3) of Subsection C of 20.2.50.116 NMAC: (1) conduct quarterly monitoring, or (2) comply with equipment leak and fugitive emissions monitoring requirements set out in federal NSPS so long as such standards are at least as stringent as the NSPS OOOOa, 40 C.F.R. Part 60, as in existence on the effective date of the Proposed Rules. Joint Proposal, at 1–2.

The Department adopted the Joint Proposal in the December 16 Draft, and retained it in the January 18 Draft. Prior to this change, transmission compressor stations had been subject to the same LDAR inspection frequencies as gathering and boosting stations and natural gas processing plants. See Petition, Draft Proposed Rules, 20.2.50.116.C.(3)(b) NMAC. During the hearing, when asked if "the Department recognize[s] and agree[s] that the VOC content of natural gas transported by a transmission compressor station is lower – much lower than the VOC content of gas moved in gathering and boosting and at gas plants," the Department's witness responded, "Yes." Hearing Transcript, Vol. 8, 2441:24–2442:4. Next, when asked if the Department's witness "agree[d], then, that it would be reasonable to treat transmission compressor stations differently than [gathering and boosting stations and natural gas processing plants] with respect to inspection frequency" under the LDAR rule proposal, the witness again responded, "Yes." Id. at 2442:5-9. The Department then stated that it supports the Joint Proposal. Id. at 2444:25–2445:4. The Department also acknowledged that stringency in the context of an LDAR program is a function of how frequently inspections are required, and that the Department's goal with respect to LDAR at transmission compressor stations is that inspections will be conducted at least quarterly. Hearing Transcript, Vol. 8, 2445:5–2446:15. The Joint Proposal is now reflected in the January 18 Draft at 20.2.50.116.C.(3)(d) NMAC. Kinder Morgan respectfully requests that the Board adopt the Joint Proposal in the final rule.

Many sources, including many transmission compressor stations, are subject to EPA's LDAR program, and the federal LDAR program may differ from the state LDAR program, creating implementation challenges. Compounding these matters is the fact that the VOC content of natural gas present at a transmission compressor station is very low relative to the natural gas in other segments of the oil and gas industry. To address these issues, the Board should adopts 20.2.50.116.C.(3)(d) NMAC, which affords transmission compressor stations two compliance options for the frequency of monitoring under Paragraph (3) of Subsection C of 20.2.50.116 NMAC: (1) conduct quarterly monitoring, or (2) comply with equipment leak and fugitive emissions monitoring requirements set out in federal NSPS so long as such standards are at least as stringent as the NSPS OOOOa, 40 C.F.R. Part 60, as in existence on the effective date of the Proposed Rules. This approach ensures that transmission compressor stations are monitoring at least quarterly while appropriately managing overlap with the federal LDAR program.

<u>CEP adds support for the Joint Proposal:</u> Gathering compressor stations are one of the largest sources of emissions, contributing about 20% of total emissions. 8 Tr. 2546:16-18. According to Dr. Lyon, there have been several recent studies that have looked at methane emissions from gathering and boosting stations, including an EDF-sponsored study for Colorado State University that used site-level measurements to estimate gathering compressor emissions. Colorado State University has conducted subsequent work looking at component-level emissions and found that compressors can have leaks and anomalous emissions. 8 Tr. 2579:22-2580:6. Recent work by EDF, including aerial surveys by Carbon Mapper, have found that in the Permian Basin, gathering stations are a disproportionately large source of emissions compared to other basins, with the stations

themselves accounting for about 25% of the measured methane emissions from large emitters. 8 Tr. 2580:7-13. Many of these emissions are due to both leaks and inefficient operations, including flares that are not properly burned. 8 Tr. 2580:14-19. In the Permian in particular, there are pressure issues where some of the gathering pipelines are over pressurized, and have anomalous pressure relief venting from these gathering stations, causing very high emissions. 8 Tr. 2580:20-24. For this reason, in Dr. Lyon's opinion, it is critical that the sites are maintained well, including making sure they are operating under proper pressure, to avoid large emissions from gathering compressor stations. 8 Tr. 2580:25-2581:4.

It is critical to have frequent LDAR at gathering stations because they can have anomalous very high emission events. 8 Tr. 2581:7-12. Through EDF's analyses, Dr. Lyon has found that these emission events can be short-term, often only a couple hours or days. 8 Tr. 2581:7-12. It is critical to continuously look for problems by doing frequent inspections and, if possible, have some kind of continuous monitoring of these facilities to make sure that when operators notice problems, they are fixed very quickly. 8 Tr. 2581:13-18.

The Department's proposal will reduce significant pollution from compressor stations. The Department's proposal requires quarterly LDAR for gathering compressor stations emitting less than 25 ton per year VOC and monthly LDAR for compressor stations emitting equal to or greater than 25 ton per year VOC. 8 Tr. 2609:5-8. Based on Ms. Hull's analysis, the Department's LDAR requirements for well sites and gathering and boosting compressor stations is highly cost effective and will remove 153,000 tons of VOCs from the atmosphere annually. In addition, the program has a co-benefit of reducing 531,000 tons of methane annually. 8 Tr. 2610:9-14.

NMOGA's proposal will leave thousands of tons of pollution unabated. Ms. Hull estimated the pollution that will be left unabated if the EIB adopts NMOGA's compressor stations LDAR proposal. According to Ms. Hull, NMOGA's proposal to decrease the frequency of inspections at well sites and compressor stations will result in the release of thousands of additional tons of volatile organic compounds and methane to the atmosphere annually. These emissions contribute to unhealthy levels of ozone pollution and the climate crisis. 8 Tr. 2594:22-2595:3. Compared to the Department's proposal, NMOGA's proposal decreases the inspection frequency from monthly to quarterly for compressor stations emitting 25 ton per year VOC or more and from quarterly to semi-annually for those emitting below 25 ton per year VOC. 8 Tr. 2609:9-13. Ms. Hull estimates NMOGA's proposal will result in up to 8,400 additional tons of VOC and up to 34,000 additional tons of methane leaked annually using EDF emission estimates that would not be leaked to the atmosphere if the Board adopted the Department's proposal. 8 Tr. 2609:19-25; EDF Ex. JJJ at 5.

Ms. Hull found that NMOGA's proposal to reduce the frequency of leak inspections at compressor stations will result in a 20% decrease in emission reductions from gathering and boosting sites. EDF Ex. JJJ at 3. Frequent LDAR, as the Department has proposed, can effectively curb the unhealthy levels of ozone pollution that form in part from oil and gas operations, including from compressor stations. 8 Tr. 2595:4-5.

<u>NMOGA opposes the Joint Proposal:</u> Many owners and operators of oil and gas operations subject to Part 50 already conduct extensive leak detection and repair efforts pursuant to federal New Source Performance Standards under 40 C.F.R. Part 60, Subpart OOOO and OOOOa. The Board should find that leak detection and repair efforts conducted pursuant to these or any other state- or federally-mandated programs satisfy the conditions of 20.2.50.116 NMAC to the extent that they require identical or more stringent monitoring activities. For existing well sites and standalone tank batteries, proposed Part 50 requires the owner or operator to comply with 20.2.50.116.C.3 within two years of the effective date. The Board should find that a similar two-year phase-in for inactive well sites, gathering and boosting stations, natural gas processing plants, and transmission compressor stations is appropriate.

For well sites and standalone tank batteries, proposed Part 50 would require facilities with a PTE less than two tpy VOC to conduct annual OGI or EPA Method 21 surveys, facilities with a PTE equal to or greater than two tpy VOC and less than five tpy VOC to conduct semiannual surveys, and facilities with a PTE equal to or greater than five tpy VOC to conduct quarterly surveys. 20.2.50.116.C(3)(b) NMAC. For gathering and boosting stations and natural gas processing plants, owners and operators would have been required to conduct quarterly surveys at facilities with a PTE less than 25 tpy VOC and monthly surveys at facilities with a PTE equal to or greater than 25 tpy. 20.2.50.116.C(3)(c) NMAC. For transmission compressor stations, owners and operators would have been required to conduct quarterly surveys or complete surveys in compliance with 40 C.F.R. Part 60, provided the federal standards are at least as stringent as the current requirements under 40 C.F.R. Part 60, Subpart OOOOa. 20.2.50.116.C(3)(d) NMAC. For well sites within 1,000 feet of an occupied area, owners and operators would have been required to conduct surveys quarterly at facilities with a PTE less than 5 tpy VOC and monthly at facilities with a PTE equal to or greater than 5 tpy VOC. 20.2.50.116.C(3)(e) NMAC. For wellhead only sites and inactive well sites, owners and operators would have been required to conduct annual surveys. 20.2.50.116.C(3)(f),(g) NMAC. The parties generally agree on the proposed leak standards for 20.2.50.116.C(3)(d),(f), and (g). The Board should find the leak survey requirements in 20.2.50.116.C(3)(d),(f), and (g) are supported by the record. The remaining leak standards remain controversial.

While leak detection and repair measures reduce VOC emissions, the record does not demonstrate that reducing VOC emissions will significantly redress injuries to New Mexico air quality associated with ozone. The areas of New Mexico impacted by this rule are NOx sensitive, meaning that VOC emissions reductions have a relatively modest impact on ozone concentrations, particularly in the quantities attributable to anthropogenic sources, such as oil and gas. As Mr. McNally testified, “additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County.” NMOGA Exhibit A4:16.

VOC emissions reductions attributable to leak detection and repair measures diminish rapidly with increasing frequency. Mr. Smitherman credibly testified that most leaks are identified and repaired during initial surveys. NMED’s own data demonstrates that 40% of all emissions reductions from LDAR are achieved with annual surveys, 60% are achieved with semiannual surveys, and 80% are achieved with quarterly surveys. NMOGA Exhibit 58:14. A study from the American Petroleum Institute consisting of 6,000 surveys across 3,482 sites also found less than 2 leaks per site during initial surveys, with the leak rate falling quickly to less than 1 leaking component on average in subsequent surveys. NMOGA Exhibit 25:B-2. The Board should give weight to the diminishing returns that occur with increasing leak frequency.

The leak detection frequencies proposed by the Department would impose unreasonable costs on the oil and gas industry relative to the ozone benefits projected to occur and, therefore, are not supported by the weight of evidence. The Board should find that NMOGA's methodology more credibly estimates the cost of leak detection and repair requirements. For well sites, NMOGA's analysis uses NMED's own data, except that NMOGA has used a different model plant. Smitherman testimony, Tr. 8:2673:12-25 - 2674:1-15. While NMED relied on a model plant from data developed in 1996 based on equipment surveys conducted outside of New Mexico, NMOGA relied on a model plant derived from data gathered from New Mexico oil and gas operators in 2019. Smitherman Testimony, Tr. 8:2668:1-11. NMOGA's more recent and geographically relevant data came from EPA's 2019 GHG report and showed that, on average, New Mexico sites have fewer pieces of equipment per site, fewer components per piece of equipment, and lower potential leak emissions than was observed in the 1996 study NMED has relied upon. NMOGA Exhibit 58:9. Similarly, while NMED relied on gathering and boosting station model plant data derived from a 1996 EPA/GRI study, NMOGA relied on a 2019 Colorado State University study, which showed fewer equipment, fewer components, and lower potential leak emissions relative to NMED's data. Smitherman testimony, Tr. 8:2678:23-25 - 2679:1; NMOGA Exhibit 28; NMOGA Exhibit 58:28. By relying on more current and geographically relevant model plant data, the Board should finds that NMOGA has put forward a more credible methodology for estimating the costs of LDAR for New Mexico oil and gas operators at varying frequencies and thresholds.

Based on this more refined analysis, the Board should find that the incremental costs of the greater frequencies at the lower thresholds proposed by NMED are not economically reasonable. As the emissions reductions available reduces with increased frequency, the per-survey cost of conducting LDAR remains relatively the same, meaning that less emissions per dollar are reduced with each survey. Smitherman testimony, Tr. 8:2688:11-15. NMOGA's technical testimony demonstrates that the incremental costs associated with increasing LDAR frequency are exorbitant. NMOGA Exhibit 58:46-48, 50, 54-56. For example, under NMOGA's proposal, an oil well site with a PTE of 4 tpy VOC would be required to conduct an annual survey, while NMED's proposal would require a semiannual survey. The cost-per-ton of VOC reduced of going from an annual to semiannual survey is between $16,448 and $21,028 per ton. NMOGA Exhibit 58. Given the limited impact of VOC reduction on ozone, adopting a semiannual frequency for such facilities would be inconsistent with the Board's duty to consider and give the weight it deems appropriate to economic reasonableness and the proposal's capacity to redress the targeted injury.

The Department declined the invitation to revise Part 50 to make clear that a leak, in and of itself, is not a violation if repaired. As Ms. Bisbey-Kuehn explained, "There may be instances where the Department discovers egregious violations from leaking components that present an imminent and substantial danger to human health or the environment or repeated leaks from the same components that indicate a systemic pattern of failure by the owner or operator to maintain sources and components in good working order." Tr. 8:2458:13-19. The Board should find that, based on the weight of substantial evidence, violations of Part 50 for leaking equipment should be limited to instances of failure to repair consistent with 20.2.50.116 NMAC or instances when the Department identifies "leaking components that present an imminent and substantial danger to human health or the environment or repeated leaks from the same components that indicate a systemic pattern of failure."

The Board should find that the leak survey frequencies proposed in the NMOGA Final Redline at 20.2.50.116.C.3(b)-(c) NMAC are reasonable and supported by substantial evidence and the weight of evidence.

(e) for well sites within 1,000 feet of an occupied area:
(i) quarterly at facilities with a PTE less than five tpy VOC; and
(ii) monthly at facilities with a PTE equal to or greater than five tpy VOC.

<u>NMED:</u> The Department is proposing that the Board adopt the proposal of CAA and EDF to require enhanced inspection frequencies for well sites within 1,000 feet of an occupied area as defined in Part 50 (the "Proximity Proposal"). Specifically, inspections would be required quarterly at facilities with a PTE less than 5 tpy VOC, and monthly at facilities with a PTE equal to or greater than 5 tpy VOC. In support of this proposal, the

Department refers the Board to the testimony of EDF witness Dr. Tammy Thompson (EDF Exhibit TT, and Tr. Vol. 2717:11 – 2729:2, 2735:20 – 2741:11), and CAA witness Lee Ann Hill (CAA Exhibit 25, and Tr. Vol. 9, 2836:21 – 2847:1, 2849:20 – 2858:25).

CEP and Oxy support the LDAR Proximity Proposal: Prior to and during hearing, the Community and Environmental Parties and Oxy came to a consensus on the proposal to increase the frequency of inspections at well sites located within 1,000 feet of an "occupied area." See, e.g., CAA Ex. 26 at 17 [Joint Proposed Second Revised Amendments to Proposed 20.2.50 NMAC]; Oxy Reb. Ex. 1 at 16. At the close of evidence on this section during the hearing, the Department adopted the Proximity Proposal as well and proposes it for adoption by the EIB. Notably, there is widespread support for the proximity proposal.

The Proximity Proposal requires more frequent LDAR inspections at wellsites 1,000 feet within an "occupied area" (defined at 20.2.50.7.LL NMAC), which generally include homes, businesses, schools, and parks. The Proposal requires quarterly inspections for facilities with PTE of less than 5 tpy VOC and monthly inspections for facilities with PTE equal to or greater than 5 tpy VOC.

Implementation of the Proximity Proposal will help keep New Mexico in compliance with federal ozone standards and has the co-benefits of reducing methane, a potent greenhouse gas, and reducing air pollutants harmful to human health. People who live, work, and play in close proximity to oil and gas operations are at higher risk of suffering from adverse health impacts due to exposure to pollutants emitted from oil and gas operations. In New Mexico, substantial numbers of persons of color, Native Americans, and vulnerable individuals live within 1,000 feet of well sites, many of whom already suffer from health conditions that can be exacerbated by exposure to additional pollution from oil and gas sources. The benefits of this proposal are great while the costs are reasonable. The proximity proposal will reduce VOCs and help New Mexico stay in attainment with federal health-based standards for ozone

The Proximity Proposal will reduce volatile organic compounds that contribute to ozone pollution, thereby helping New Mexico protect clean air and remain in attainment with the NAAQS for Ozone. EDF Ex. TT at 3. EDF estimates that the Proposal will impact 3,365 or 7.7% of the sites in the state, will reduce VOC emissions by 3,600 tons per year, and will increase VOC emissions reductions at those sites by 73%. These reductions in VOCs will help New Mexico reduce local formation of ozone and help New Mexico stay in attainment of the NAAQS for ozone. 8 Tr. 2718:6-22, -2595:19-20.

Air pollutants hazardous to human health, the environment, and the climate — including greenhouse gases, hazardous air pollutants, and criteria air pollutants — are emitted from upstream oil and gas development sites. CCA Ex. 25 at 1 [Hill Reb. Test.]. Air pollutants emitted directly from oil and gas facilities may also contribute to the secondary formation of air pollutants in the atmosphere that also pose risks to human health and the environment (e.g., ground-level ozone). CCA Ex. 25 at 1.

At least 61 HAPs have been measured near upstream oil and gas sites or investigated from secondary data sources in the peer-reviewed literature. HAPs emitted from oil and gas facilities include benzene which is a known human carcinogen, toluene, ethylbenzene, xylene, and n-hexane. CCA Ex. 25 at 7-9. The risks to human health from VOCs emitted from oil and gas facilities are many and varied and include harm to the central nervous system, eyes, skin and respiratory tracts, as well as the liver, kidney, and endocrine systems. CCA Ex. 25 at 7-9.

Persons living, working, and going to school near oil and gas facilities are at greater risk due to emissions of air pollutants. Chronic or long-term exposure to VOCs, NOx, and ground-level ozone may result in longer lasting or more severe public health consequences. Generally, the duration of exposure is a key factor that influences the development of adverse health outcomes. CAA Ex. 25 at 10. There is a reasonable degree of scientific certainty that living in close proximity to oil and gas facilities results in increased health risks and impacts from elevated air pollution levels and that these health risks are increasingly attenuated further from these operations. CAA Ex. 25 at 2, 11. The public health risks and impacts associated with air pollutant emissions from oil and gas facilities that go unaddressed would be disproportionately experienced by people who live, work, and go to school near oil and gas facilities. CAA Ex. 25 at 2-3.

Peer-reviewed air quality health risk assessment studies indicate cancer and noncancer health risks increase with increasing proximity to oil and gas development sites. CAA Ex. 25 at 14. The scientific literature points to the need for frequent if not continuous leak detection using modern and advanced leak detection methods capable of identifying leaks. EDF Ex. RR at 8. The body of epidemiological literature strongly supports that geographic proximity to active oil and gas development is an important risk factor for a variety of adverse health outcomes, including: respiratory outcomes, cardiovascular outcomes and cardiovascular disease indicators, childhood cancer, hospitalizations, and adverse birth outcomes. CCA Ex. 25 at 1, 14-15.

The increased frequency of LDAR inspections within 1,000 feet of "occupied areas" proposed by the Community and Environmental Parties, the Environment Department, and Oxy at 20.2.50.116 NMAC is a targeted strategy to increase public health protections. The proximity proposal will protect the health of vulnerable persons living near oil and gas facilities, some of whom already suffer from adverse health conditions. EDF estimates that the proposal will protect the health of over 35,000 New Mexicans living within 1,000 feet of a wellsite. Of those, over 2,700 are children under the age of 5, more than 4,500 are adults 65 years or older, more than 5,700 are living in poverty, and 19,000 are people of color, including over 5,800 Native Americans. EDF Ex. SS at 15.

Many of these people already suffer from health conditions that could be exacerbated by exposure to additional air pollution. These include more than 3,800 adults with asthma, over 2,200 adults with coronary heart disease, almost 2,600 with chronic obstructive pulmonary disease, and more than 1,200 adults who have experienced or are at risk of a stroke. EDF Ex. DD; EDF Ex. SS at 15; 8 Tr. 2596:23-2597:4. Many of the people living within 1,000 feet of a well site in New Mexico are people of color and Native Americans. 8 Tr. 2626:14-16. People of color and Native Americans in New Mexico are at a disproportionately higher risk of health conditions exacerbated by additional air pollution, which includes asthma, heart disease and cancers. 8 Tr. 2624:16-24, 2626:17-21.

The Proximity Proposal is cost effective. The Proposal's LDAR requirements are highly cost effective when calculating the compliance costs divided by the VOC reductions. The Proposal will increase annual emissions reductions by 3,600 tons of VOC. 8 Tr. 2595:19-20. This represents an incremental increase in LDAR costs of $4.8 million (or 13% higher) from the Department's initial proposal, and results in an average cost of $894 per ton VOC reduced within the proposed 1,000 foot boundary (or $349 per ton VOC reduced statewide). EDF Ex. DD; EDF Ex. SS at 4-5; 8 Tr. 2595:19-20. A review of other jurisdiction's LDAR requirements demonstrates that an average cost of $894 per ton of VOC reduced is very reasonable, as other jurisdictions have adopted LDAR requirements with significantly higher compliance costs. 8 Tr. 2599:2-2600:1. The costs to implement the Proximity Proposal are economically feasible and entirely reasonable. 10 Tr. 3214:19-22.

In summary, the Proximity Proposal is beneficial for several reasons:

1. The Proximity Proposal will reduce volatile organic compounds that contribute to ozone pollution, thereby helping New Mexico protect clean air and remain in attainment with the National Ambient Air Quality Standards for Ozone. EDF Ex. TT at 3.

2. The Proximity Proposal results in the co-benefits of reducing methane and HAPs emissions. The proximity proposal will secure important co-benefits by reducing 14,300 tons of methane and 150 tons of hazardous air pollutant annually. 8 Tr. 2593:21-23; EDF Ex. SS at 11.

3. Air pollutants hazardous to human health, the environment, and the climate — including greenhouse gases, hazardous air pollutants, and criteria air pollutants — are emitted from upstream oil and gas development sites. CCA Ex. 25 at 1.

4. There is a reasonable degree of scientific certainty that living in close proximity to oil and gas facilities results in increased health risks and impacts from elevated air pollution levels and that these health risks are increasingly attenuated further from these operations. CAA Ex. 25 at 2, 11.

5. The Proximity Proposal will protect the health of vulnerable persons living near oil and gas facilities. EDF estimates that the proposal will protect the health of over 35,000 New Mexicans living within 1,000 feet of a wellsite. EDF Ex. SS at 15.

6. The Proximity Proposal's LDAR requirements are highly cost effective when calculating the compliance costs divided by the VOC reductions. EDF analysis and a comparison of the cost effectiveness of the proximity proposal to similar inspection requirements adopted by other air quality agencies support the cost effectiveness of the proposal. 10 Tr. 3214:19-22. <u>See also CEP proposed SOR 122-152.</u>

IPANM opposes the Proximity Proposal: In addition to NMED's proposals, EDF made its own proposal regarding proximity of facilities to occupied residences as part of a request to increase the frequency of LDAR monitoring in 20.2.50.116. EDF Ex. SS at 4 (Hull). EDF proposed that operators must perform LDAR inspections of well sites at greater frequencies when a regulated site is located within 1,000 feet of an occupied area. EDF Ex. SS at 4 (Hull).

This proposal included adding a new definition to 20.2.50.7 NMAC for an "occupied area" that generally provided boundaries and criteria for what would be considered an occupied area. EDF Ex. VV at 3 (Proposed Redline of Rule). It also included additional monitoring requirements under 20.2.50.116(C)(3)(c) NMAC that increased LDAR monitoring frequency for wells near occupied areas. Id. at 17.
EDF was joined by CAA, CCP, NAVA, and Oxy in their proposal. EDF Rebuttal NOI at 1-2; Tr. Vol. 8, 2539:17-23 (Lyons) The New Mexico Environmental Law Center also supported this proposal. Tr. Vol. 8, 2577:14-22 (Lyons).

At the hearing, EDF's witness, Dr. Lyons testified about this proposal and its purpose to "protect frontline communities from excess emissions while also helping New Mexico avoid ozone nonattainment". Tr. Vol. 8, 2539:17-2540:9 (Lyons).
Another EDF witness, Ms. Hull, testified in response to a question about how the proximity proposal relates to exceedances of federal ozone NAAQS that the proximity proposal is a "reference to all [pollutants] . . . that are associated with oil and gas that are creating negative health impacts." Tr. Vol. 8, 2621:1-6. EDF witness, Dr. Thompson testified regarding the Proximity Proposal that she believes it goes to both compliance with NAAQS and preventing unnecessary health risks. Tr. Vol. 8, 2731:18-19. The Proximity Proposal was questioned by IPANM as being unrelated to regulation of ozone precursors and implementing ozone NAAQS. Tr. Vol. 8, 2733:8-22 (Rose). The Board should find that the Proximity Proposal is unrelated to the implementation of the federal ozone NAAQS and therefore cannot be included in the final rule.

NMOGA opposes the Proximity Proposal: The Department has endorsed the leak detection and repair proposal requiring owners and operators of well sites within 1,000 feet of an occupied area to conduct quarterly surveys at sites with less than 5 tpy VOC and monthly surveys at sites with 5 tpy or more VOC. 20.2.50.116.C.3(e) NMAC. Increasing LDAR within one-thousand feet of an occupied area is not related to reducing ozone concentrations for those targeted locales. Instead, as Ms. Lee Ann Hill, witness for CAA testified, the concern driving the LDAR proximity proposal is the direct emissions of VOCs and hazardous air pollutants, not the secondary ozone that may form as the results of these direct emissions. Tr. 9:2847:21-25 – 2849:1-6. When questioned about whether ozone would form within 1,000 feet of the wellhead, Ms. Hill testified that she had "not personally evaluated ozone formation given particular distances from oil and gas sites." See Tr. 9:2848:15-21. Other witnesses questioned on this point did not provide testimony or evidence that ozone formation within 1,000 feet of a well site is occurring or will be prevented by the implementation of this standard in a way that will meaningfully contribute to the attainment and maintenance of the primary ozone standard. See, e.g., Tr. 8:2730:4-25 – 2735:1-11.

Because the LDAR proximity proposal has no federal corollary, it is more stringent than federal requirements and is subject to NMSA 1978, § 74-2-5.G. Given that the record contains no evidence that ozone forms within 1,000 feet of a wellhead, the Board has no evidence upon which to conclude the standard is more protective of the primary benefits targeted by this rulemaking, ozone reductions. The statutory authority for this rulemaking and the public notice provided do not contemplate regulation of direct emissions for purposes unrelated to ozone formation. Adopting such standards as part of this rulemaking would deprive the public of fair notice and exceed the operative statutory authority, contrary to law. This does not foreclose the Department or any other party from petitioning the Board to adopt these standards in a different context.

The Board should reject the Proximity LDAR Proposal because it is beyond the scope of this rulemaking, does not demonstrably contribute to the objective of attaining and maintaining the primary ozone standard, and is not cost-effective. Ensuring attainment and maintenance of the ozone standards is the statutorily prescribed objective of this rulemaking. Per the statute, the rule ultimately adopted by the Board seeks to "provide for attainment and maintenance of the primary ozone NAAQS" set by EPA in areas of the state "where the ozone concentrations exceed ninety-five percent" of the standard. NMSA 1978, § 74-2-5.C. The Board lacks authority to adopt any Department or stakeholder proposals that do not demonstrably contribute to this attainment and maintenance goal.

This limitation is imposed by the statute itself. Under NMSA 1978, § 74-2-5.C, the Board is authorized to adopt a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds. However, this authority is limited those measures necessary "to provide for attainment and maintenance of the standard." *Id.* Consequently, proposals that call for control of air toxics, for example, in ways that have nothing to do with mitigating ozone are not within the Board's authority in this rulemaking. While the Board may adopt standards that have co-benefits, such as NOx emissions limits for engines that also reduce hazardous air pollutant emissions, a proposal must provide a demonstrable benefit towards attaining or maintaining the primary ozone standard. If a proposal does not, it is not made "to provide for attainment and maintenance of the standard," and it is beyond the scope of Board's authority under NMSA 1978, § 74-2-5.C. The Board does not have authority to adopt standards that only provide or primarily provide a benefit tangential to the primary target of the regulation, and allowing adoption of such rules would remove all effective limits on rulemaking authority. Ms. Paranhos, representing EDF, conceded as much. Tr. 8:1245:20-8:1246:2.

The Board is also limited to adopting rules that provide for the attainment and maintenance of the ozone standard because that is what Board's public notice stated. Pursuant to NMSA 1978, § 10-15-1, the Board must provide public notice announcing its intention to consider a petition by the Department to adopt rules addressing ozone. "Compliance with prescribed notice requirements is a prerequisite to any valid action by [the Board], and failure to give proper notice constitutes a jurisdictional defect rendering action of [the Board] null and void." N.M. Att'y Gen. Op. No. 90-29 (Dec. 20, 1990). The public notice provided:

The purpose of this public hearing and is narrow—to reduce emissions of ozone precursor pollutants "*to ensure attainment and maintenance*" of the NAAQS standard. While the Board has authority to otherwise undertake a rulemaking to reduce pollutants that have no bearing on NAAQS, such as regulation of hazardous air pollutants, such an undertaking is not described in the public notice and is not authorized under NMSA 1978, § 74-2-5.C.

Clean Air Advocates, EDF, and others have urged the Board to require leak detection monitoring at well sites within 1,000 feet of an occupied area on a quarterly basis where sites have a PTE less than 5 tpy VOC and monthly where sites have a PTE equal to or greater than 5 tpy VOC. *See* CAA, Exhibit 22, at 17. After extensive testimony on this issue, the Department signaled its support. Mr. Smitherman, on behalf of NMOGA, also testified that NMOGA would support weekly AVOs and quarterly Method 21 or OGI, as opposed to the monthly inspections. Other industry stakeholders did not endorse more frequent LDAR for well sites near occupied areas.

While this proposal has been endorsed by the NMED and others, after fuller consideration of the evidence adduced in support of the proposal and consideration of NMSA 1978, § 74-2-5, NMOGA respectfully disagrees that the Board has authority to adopt such a rule given the evidentiary record before it. Increasing LDAR within one-thousand feet of an occupied area has no relationship to reducing ozone concentrations for those targeted locales. Instead, as Ms. Lee Ann Hill, witness for Clean Air Advocates testified, the concern driving the LDAR proximity proposal is the direct emissions of VOCs and hazardous air pollutants, not the secondary ozone that may form as the results of these direct emissions. *See* Tr. 9:2847:21-25 – 2849:1-6. When questioned about whether ozone would form within 1,000 feet of the wellhead, Ms. Hill testified that she had "not personally evaluated ozone formation given particular distances from oil and gas sites." *See* Vol. 9, 2848:15-21. Other witnesses questioned on this point failed to provide any testimony, let alone evidence, that ozone formation within 1,000 feet of a well site is occurring or will be prevented by the implementation of this standard in a way that will ensure attainment and maintenance of the primary standard. *See, e.g.,* Vol. 8, 2730:4-25 – 2735:1-11. As CDG witness, Ms. Lori Marquez testified, "ozone is a regional pollutant," and "technical work performed by EPA demonstrates that individual minor sources in New Mexico [such as well head sites subject to the proximity proposal] do not cause or contribute to ozone NAAQS violations." Testimony of Lori Marquez, Tr. 5:1476:15-19. The purpose of this rulemaking is to ensure attainment and maintenance on a large scale—in counties and groups of counties.

Because the LDAR proximity proposal has no federal corollary, it is more stringent than federal requirements and triggers the heightened substantial evidence standard in NMSA 1978, § 74-2-5.G. Given that the record contains no evidence that secondary ozone is forming within 1,000 feet of a wellhead, the Board has no evidence upon which to conclude the standard is more protective of the primary benefits targeted by this rulemaking—ozone reductions. Although the record contains evidence that the LDAR proximity proposal may be more protective in a general sense, that is not sufficient to satisfy the statutory standard for this rulemaking. The statutory authority for this rulemaking and the public notice provided do not contemplate regulation of direct emissions for purposes unrelated to ozone formation. Adopting such standards on this basis as part of this rulemaking would deprive the public of fair notice and exceed the operative statutory authority.

If the Board determines against this weight of evidence that it has authority and has provided sufficient notice, the Board should not adopt any standard more stringent than NMOGA's good faith offer to conduct weekly AVO inspections and quarterly Method 21 or OGI monitoring within 1,000 feet of an occupied area.

As Mr. Smitherman testified, increasing LDAR frequency yields diminishing returns. As Member Honker noted, most of the emissions reductions from LDAR come from the first few cycles of conducting the survey. Although emissions available for reduction decrease the more frequently surveys are conducted, the primary cost driver of conducting LDAR—the survey itself—remains the same. The more frequently LDAR is conducted, the less frequently leaks are identified, the less emissions there are to prevent, and the less cost-effective the entire exercise becomes. This fact becomes especially apparent when reviewing the incremental cost-effectiveness of conducting LDAR. Consider the cost effectiveness of moving from semiannual to quarterly LDAR surveys:

Incremental cost per ton of VOC reduction - ERG Costs & NMOGA Reductions			
Semiannual to Quarterly	Incremental VOC Reductions (tpy)	Incremental Annual Cost (2019)	Incremental Cost per Ton
NG Well Site	0.255	$ 2,011	$7,899
Oil Well Site (GOR < 300)	0.048	$ 2,011	$42,078
Oil Well Site (GOR > 300)	0.061	$ 2,011	$32,913

NMOGA Exhibit 58, at 48.

While the costs are excessive for natural gas well sites, they are astronomical for oil well sites. Mr. Smitherman conducted additional analysis on the costs of transitioning from quarterly to monthly LDAR consistent with the LDAR proximity proposal; this is analysis is contained in the proffered materials for which Board has yet to issue a ruling. But the Board can draw its own conclusions from the evidence already in the record: if transitioning from twice a year to four times a year is not cost-effective, transitioning from four times a year to twelve times a year is also not cost-effective. Because the rationale for increasing LDAR near well sites is not targeted at the ozone problem, the Board lacks authority to adopt this proposal as part of this rulemaking. While the Board may have authority to adopt such a proposal in a properly noticed public hearing addressing this issue, that is not the case here, where the statutory basis and public notice only contemplate measures to address ozone.

NMOGA proposes changes to paragraph (e):

(e) quarterly for well sites within 1,000 feet of an occupied area:

~~(i) quarterly at facilities with a PTE less than 5 tpy VOC; and~~

~~(ii) monthly at facilities with a PTE equal to or greater than 5 tpy VOC.~~

NMOGA: NMOGA's proposed inspection frequencies and thresholds achieve significant emissions reductions, are supported by the record, and should be adopted by the Board. NMOGA urges the Board to not adopt the Department's proposed thresholds and frequencies under 20.2.50.116 NMAC, which imposes unduly burdensome leak detection and repair requirements that contribute little to the statutorily prescribed goals of ozone attainment and maintenance. The Department's proposed leak inspection frequencies under 20.2.50.116.C(3)(b), (c), and (e) impose a stringency that does not account for the diminishing returns of repetitive inspections and the escalating, exorbitant incremental costs. The proximity proposal under 20.2.50.116.C(3)(e) to require more frequent inspections at well sites within 1,000 feet of an occupied area also miss the mark and is worrying vague. The Board's authority under NMSA 1978, § 74-2-5.C and the notice provided to the public require that standards under 20.2.50 NMAC be targeted at attaining and maintaining the ozone primary standards. The proximity proposal is directed at mitigating impacts from direct emissions, not from ozone, which expert testimony admitted would not form in the 1,000-foot distance prescribed. Testimony of Lee Ann Hill, Tr. 9:2848:10-10:2849:6.

(f) for existing wellhead only facilities, annual inspections shall be completed on the following schedule: 30% by January 1, 2024; 65% by January 1, 2025; and 100% by January 1, 2026.

NMED: For existing wellhead only facilities, the Department is proposing that owners and operators conduct annual inspections that beginning after the effective date of Part 50 according to the specified phase-in schedule. This language was included based on a proposal by Oxy USA in lieu of Oxy's previous proposal to entirely exempt such facilities from the LDAR requirements. The Board should adopt this proposal for the reasons stated in Tr. Vol. 8, 2524:18 – 2526:24.

(g) for inactive well sites:

(i) for well sites that are inactive on or before the effective date of this Part, annually beginning within six months of the effective date of this Part;

(ii) for well sites that become inactive after the effective date of this Part, annually beginning 30 days after the site becomes an inactive well site.

NMED: For inactive well sites, NMED is proposing annual inspections beginning within 6 months of the effective date of Part 50 for well sites that are inactive on or before the effective date. For well sites that become inactive after the effective date, the requirement to conduct annual inspections would begin 30 days after a site becomes an inactive well site. This language was also included based on a proposal by Oxy USA. The Board should adopt this proposal for the reasons stated in Tr. Vol. 8, 2524:18 – 2526:24.

NMOGA proposes changes to paragraph (g):

(g) ~~for inactive well sites:~~

~~(i) for well sites that are inactive on or before the effective date of this Part, annually beginning within 6 months of the effective date of this Part;~~

(ii) for well sites that become inactive after the effective date of this Part, annually beginning 30 days after the site becomes an inactive well site.

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

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

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

NMED: Paragraph (4) of Subsection C of Section 20.2.50.116 requires that instruments used in inspections using EPA Method 21 must be calibrated pursuant to the procedures specified in that method, as well as by the instrument manufacturer, before each day of use. Regulated leaks are defined as those with a measurement of 500 ppm or greater of hydrocarbons and that are not associated with normal operations. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86, and NMED Rebuttal Exhibit 1, pp. 60-61.

(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; and

(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.

NMED: Paragraph (5) of Subsection C of Section 20.2.50.116 requires that inspections using OGI must comply with the requirements in EPA's regulations at 40 C.F.R. Section 60.18. Under this method, a leak is deemed to exist if the emission images recorded by the OGI instrument are not associated with normal equipment operation. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86.

(6) 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;

(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.

NMED: Paragraph (6) of Subsection C of Section 20.2.50.116 provides that components that are difficult, unsafe, or inaccessible to monitor are not required to be inspected until it becomes feasible to do so. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 82-86, and NMED Rebuttal Exhibit 1, p. 61.

(7) Owners and operators of well sites must conduct an evaluation to determine applicability of Subparagraph (e) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC within 30 days of constructing a new well site, and within 90 days of the effective date of this Part for existing well sites.

CEP proposes to insert a sentence here:

"Homeowners may contact NMED to request an owner or operator conduct the evaluation required by this Part."

(8) An owner or operator conducting an evaluation pursuant to Paragraph (7) of Subsection C of Section 20.2.50.116 NMAC shall measure the distance from the latitude and longitude of each well at a well site to the following points for each type of occupied area:

(a) the property line for indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities and outdoor venues or recreation areas;

(b) the property line for outdoor venues or recreation areas, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly;

(c) the location of a building or structure used as a place of residency by a person, a family, or families; and

(d) the location of a commercial facility with five-thousand (5,000) or more square feet of building floor area that is operating and normally occupied during working hours.

NMED: Paragraphs (7) and (8) of Subsection C of Section 20.2.50.116 are part of EDF and CAA's Proximity Proposal. These provisions are necessary for determining what facilities are subject to the LDAR requirements under that provision. In support of this proposal, the Department refers the Board to the testimony of EDF witness Dr. Tammy Thompson (EDF Exhibit TT, and Tr. Vol. 2717:11 – 2729:2, 2735:20 – 2741:11), and CAA witness Lee Ann Hill (CAA Exhibit 25, and Tr. Vol. 9, 2836:21 – 2847:1, 2849:20 – 2858:25).

NMOGA proposes changes to paragraphs (7) and (8):

(7) Owners and operators of well sites subject to the requirements in Subparagraph (e) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC must conduct an evaluation to determine applicability ~~within 30 days of constructing a new well site, and within 90 days of the effective date of this Part for existing well sites~~ prior to the applicable compliance date specified in Subparagraph (a) of Paragraph (3) of Subsection C of Section 20.2.50.116 NMAC. An evaluation is not required if the frequency requirements in subparagraph (e) are being met.

(8) An owner or operator conducting an evaluation pursuant to Paragraph (7) of Subsection C of Section 20.2.50.116 NMAC shall measure the distance from the latitude and longitude of the center of each ~~well at a~~ well site to the following points for each type of occupied area:

(a) the property line for indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities and outdoor venues or recreation areas;

(b) the property line for outdoor venues or recreation areas, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly;

(c) the location of a building or structure being used as a place of residency by a person, a family, or families; and

(d) the location of a commercial facility with five-thousand (5,000) or more spare feet of building floor area that is operating and normally occupied during working hours.

NMOGA: An evaluation of occupied areas should not be required if the frequency under the proposed rule is being used in any event. In support of the changes in paragraph (8), NMOGA states it is making it clear how the circumference is determined; as stated, it could require multiple measurements around an irregular shape, greatly increasing cost and uncertainty while not creating more protection; and that "used" can mean use in the past. The proposed change makes it clear that the structure is "being" used as an occupied structure.

(9) Injection well sites and temporarily abandoned well sites are not subject to the leak survey requirements of Paragraphs (3) through (6) of Subsection C of 20.2.50.116 NMAC.

NMED: Paragraph (9) of Subsection C of Section 20.2.50.116 expressly exempts injection well sites and temporarily abandoned well sites from the leak survey requirements of Paragraphs 3 through 6 of Subsection C of Section 20.2.50.116. This proposal is based on language jointly proposed by Oxy USA, EDF, CAA, CCP, and

NAVA. The Board should adopt this language because leak surveys are not anticipated to result in emissions reductions at these facilities. Tr. Vol. 2525:8-21.

(10) Prior to any monitoring event, the owner or operator shall date and time stamp the monitoring event.

NMED: Paragraph (10) of Subsection C of Section 20.2.50.116 requires the owner or operator to date and time stamp each monitoring event. The Board should adopt this proposal for the reasons stated above regarding Subparagraph (b) of Paragraph (8) of Subsection A of Section 20.2.50.112. *See* NMED Rebuttal Exhibit 1, p. 23-24; Tr. Vol. 5, 1358:24 – 1359:14; 1368:21 – 1369:23; 1370:10 – 1371:5; 1428:2-25, 1427:4 – 1439:11.

D. Alternative equipment leak monitoring plans: An owner or operator may comply with the equipment leak requirements of Subsection C of 20.2.50.116 NMAC through an equally effective and enforceable 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 the department on an application form provided by the department. Within 90 days of receipt, the department shall issue a letter approving or denying the requested alternative monitoring plan. An owner or operator shall comply with the default monitoring requirements of Section 20.2.50.116 NMAC and may not operate under an alternative monitoring plan until it has been approved by the department.

(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 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 of Subsection C of 20.2.50.116 NMAC within 15 days.

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

(a) the owner or operator shall notify the department in writing of the intent to conduct monitoring under a pre-approved alternative 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 alternative monitoring plan by the owner or operator 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 the violation.

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

NMED: Subsection D of Section 20.2.50.116 provides owners and operators with the option to submit an alternative monitoring plan to comply with the monitoring requirements of Subsection C. Paragraph (1) gives the option for an owner or operator to propose an individual alternative monitoring plan for approval by the Department. The plan would have to be reviewed by a third-party prior to submission to ensure it is an equivalent, enforceable and appropriate monitory strategy. Paragraph (2) provides an option to use an alternative monitoring plan that has been preapproved by the Department. The Department will provide preapproved plans on its website and owners and operators can seek approval from the Department to use one of these preapproved plans. Use of an alternative monitoring plan must be approved by the Department and can be terminated by the Department if the owner/operator fails to comply with elements of the plan, or fails to correct or disclose a violation within 15 days of discovery. The Board should adopt this proposal because it provides flexibility to owners and operators and allows for the use of new technologies that are more efficient at discovering leaks. *See* NMED Exhibit 32, p. 84, NMED Exhibit Tr. Vol. 8, 2437:15 – 2439:16.

[NMOGA's earlier proposed revisions to Subparagraph 1(b) are not part of its final proposal.]

Oxy and CEP would insert a new (a): **"(a) proposed alternative monitoring plans may utilize alternative monitoring methods."**

Oxy: Oxy USA supports the Department's proposal to allow for alternative equipment leak monitoring plans in 20.2.50.116.D NMAC and requests that the Department clarify that this provision allows for alternative monitoring methods. Oxy USA believes this is NMED's intent, but seeks confirmation and clarification in the final rule. Other parties to the hearing already interpreted the proposed regulations to allow for alternative methods. For instance, the witness for the EDF stated that, "NMED's proposal allows operators to obtain approval to use alternative . . . equipment leak monitoring plans in Section [116.D]. Most likely many of these plans will rely on a combination of fixed [sensors], aerial surveys and/or satellites." Hearing Transcript at TR-2605:18-23. EDF's expert assumed the rule would allow the option for plans to use alternative technologies (i.e., alternative methods). Oxy USA agrees with this interpretation, but requests that the final rule make it clear on its face that alternative technologies are allowed.

In addition to being more practical, alternative monitoring methods can also be more effective. As Mr. Holderman noted in his testimony, "Oxy USA has been piloting sensor-based technology to electronically capture gas emissions, audio data and visual data from locations as an alternative compliance method to AVO inspections. This method has the potential to be a more cost effective and accurate form of data capture than traditional AVOs which can enable greater emissions reductions. Alternative technologies have potential to result in more rapid identification and response than AVO inspections." Hearing Transcript at TR-2527:5-14. In turn, more rapid identification and response capabilities allow operators to effectively reduce emissions.

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 as soon as practicable but no later than 30 days from discovery;

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

(4) if the leak cannot be repaired within 30 days of discovery without a process unit shutdown, the leak may be designated "Repair delayed," the date of the next scheduled process unit shutdown must be identified, and the leak must be repaired before the end of the scheduled process unit shutdown or within 2 years, whichever is earlier; and

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

NMED: Subsection E of Section 20.2.50.116 sets forth repair requirements for leaks detected under this Section. When a leak is detected, the component must be visibly tagged until repaired and the leak must be repaired as soon as practicable but no later than 30 days from discovery. Equipment must be re-monitored no later than 15 days after discovery of a leak to demonstrate that the leak has been repaired. In agreement with NMOGA, NMED is proposing revisions to Paragraph (4) of Subsection E to ensure that repairs will occur promptly while protecting against unexpected shutdowns. Accordingly, this provision specifies that, for leaks that cannot be repaired in the required timeframes above without a process shutdown, the leak may be designated as “Repair Delayed” and must be repaired before the end of the next scheduled process unit shutdown. For leaks that cannot be repaired in the required timeframes above due to a shortage of parts, the leak may be designated as “Repair Delayed” and must be repaired within 15 days of resolution of the shortage. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 83, NMED Rebuttal Exhibit 1, p. 62, and Tr. Vol 8, 2439:17 – 2440:13. [NMOGA’s proposed changes to E(4) have already been incorporated into NMED’s proposal.]

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM 21, OGI, or alternative equipment leak monitoring inspections conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location (latitude and longitude);

(b) time and date stamp, including GPS of the location, of any monitoring;

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

(d) name of the 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 tag was placed on the leak.

(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. If a delay is due to a parts shortage, a record documenting the attempt to order the parts and the unavailability due to a shortage is required;

(ii) the date of next scheduled process unit shutdown by which the repair will be completed; and

(iii) name of the person(s) who determined that the repair could not be implemented without a process unit shutdown.

(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.

NMED: Subsection F of Section 20.2.50.116 sets forth recordkeeping requirements for the leak monitoring and repairs required under this Section. Owners or operators must keep records of the following for all AVO, EPA Method 21, OGI, or alternative equipment leak monitoring inspections conducted pursuant to Section 20.2.50.116: facility location; date of inspection; monitoring method; name of the personnel performing the inspection; description of any leak requiring repair or a note that no leak was found; and whether a visible flag was placed on the leak or not. The owner or operator is required to record any leak detected, the date of detection, and the date of attempted repair. For leaks designated "repair delayed," the owner or operator must record the reason for delay for leaks not repaired within the allowed time frame, and an authorized representative's signature who determined the leak could not be implemented without process unit shutdown. The owner or operator must also record information regarding repair and follow-up monitoring. For a leak detected using OGI, the owner or operator must keep records as specified in EPA regulations at 40 C.F.R. Section 60.18(i)(1)-(3). Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86. [NMOGA's proposed changes to paragraphs (2)(c)(ii) and (iii) have already been incorporated into NMED's proposal.]

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]

NMED: Subsection G of Section 20.2.50.116 sets forth reporting requirements for the leak monitoring and repairs required under this Section. Owners and operators are required to certify the use of an alternative equipment leak monitoring plan under Subsection D to the Department annually. Owners and operators must also comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 84-86.

Estimated Emissions Reductions Resulting from Section 20.2.50.116

ERG estimated total emission reductions of 4,654 tons per year of VOC for non-wellhead facilities and 14,896 tons per year of VOC for well site facilities, as detailed in NMED Exhibit 32, pp. 86-88, and NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet.

Estimated Costs of Section 20.2.50.116

The costs of implementing an LDAR program to reduce fugitive equipment leak emissions are those associated with labor required to conduct inspections and repair leaking components. ERG estimated the costs required to implement a new LDAR program under the proposed rule for well sites based on estimates for well sites from the EPA CTG (NMED Exhibit 34) and from the cost analysis for the 2014 amendments to Colorado Reg. 7. *See* NMED Exhibit 71 – Colorado Dept. of Public Health and Environment, *Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6 and 7 (5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)*, (February 11, 2014) ("2014 Colorado Regulatory Analysis"). NMED Exhibit 32, p. 88. The total annualized costs of implementing the LDAR requirements in Part 50 are estimated to be $2,847,945 for non-wellhead facilities, and $52,220,185 for well site facilities. A detailed explanation of how ERG estimated these costs is provided on pages 88-90 of NMED Exhibit 32. Given the emissions reductions expected as a result of the proposed rule, ERG estimated the cost effectiveness of reducing emissions from non-wellhead facilities at $5,100 per ton of VOC, and $3,506 per ton of VOC for well site facilities. A detailed explanation for *See id.* at 88-90.

NMOGA provided extensive comments in its redline at NMOGA Appendix B, pp. 30-34, regarding NMED's cost effectiveness analyses that were used to support the proposed emission thresholds and inspection frequencies in Section 20.2.50.116.

NMOGA argued that the model plants included in the 2016 CTG were out of date and were not representative of the well sites in the San Juan and Permian Basins. NMOGA further claimed that model plants based on information in the GHGRP for the Permian and San Juan Basins better reflect well production facilities in New Mexico and should be used instead of the model plants in the 2016 CTG, and these would lead to lower emission reductions compared to those in the 2016 CTG. NMED could not evaluate the validity or representativeness of the alternative model plants mentioned by NMOGA, because NMOGA did not document in its testimony or exhibits the actual model plants they created and on which they estimated new emission reductions and cost effectiveness numbers. NMED Rebuttal Exhibit 1, pp. 62-63. The Board should therefore find that NMED properly relied on the model plants included in the 2016 CTG as the basis for its cost effectiveness analysis for this Section.

NMOGA also argued that the costs in the 2016 CTG did not account for additional cost elements that were discussed in comments submitted to the EPA on the draft CTG by the American Petroleum Institute (API). NMOGA argues that NMED should use the revised costs reflected in the API comments on the draft CTG. EPA, in its "Responses to Public Comments on the Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, October 2016," fully responded to the API comments mentioned in the NMOGA testimony and adjusted the cost estimates in the 2016 CTG as appropriate. *See* NMED Exhibit 34, pp. 191-196. The Board should find that it is beyond the scope of this rulemaking to reassess the EPA's response to these particular API comments on the 2016 CTG in the absence of any additional information from API or NMOGA relative to those original comments and EPA's response. NMED Rebuttal Exhibit 1, p. 63.

The Board should find that NMED's estimated costs associated with Section 20.2.50.116 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

<u>NMED:</u> **Description of Equipment or Process**

Liquids unloading is used to remove accumulated fluids in the wellbore of a natural gas production well. Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells, and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the gas velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow gas production to overcome the surface equipment and flow out of the wellbore. While pressure is a factor, it is generally a lack of velocity that causes liquids to accumulate in the wellbore (i.e., to "load" or "load up"). New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics, and varies from well to well. A full description of the liquids unloading process and related issues is provided in NMED Exhibit 32, pp. 91-93

Control Options

VOC emissions from liquids unloading operations occur when the well is vented to the atmosphere to unload fluids or when the liquids are unloaded through atmospheric tanks and the gas mixed with the liquid is vented to the atmosphere. To reduce emissions and waste of gas during manual (i.e., non-automated) liquids unloading activities, operators can monitor manual liquids unloading events onsite within close proximity to the well or via remote telemetry to ensure that the well returns to normal production operation as soon as possible. NMED Exhibit 32, p. 93.

Rule Language

The proposed operational requirements and best management practices for limiting VOC emissions during natural gas well liquids unloading events are based on requirements in Colorado Reg. 7, Pennsylvania GP-5 and GP-5A, and the Wyoming Permitting Guidance, as detailed in NMED Exhibit 32, pp. 95-96.

CEP supports the Department's proposal in Section 117. [See CEP's SOR 314-324.]

IPANM proposed edits throughout Section 117, see below the end of NMED's proposal.

A. Applicability: Liquid unloading operations resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Liquid unloading operations that do not result in the venting of any natural gas are not subject to this Part. Owners and operators of a natural gas well subject to this Part must comply with the standards set forth in Paragraph (1) of Subsection B of 20.2.50.117 NMAC within two years of the effective date of this Part.

NMED: The requirements of Section 20.2.50.117 apply to liquid unloading operations resulting in the venting of natural gas at natural gas wells. Owners and operators of natural gas wells that are subject to this section have two years from the effective date of Part 50 to comply with the provisions of Paragraph (1) of Subsection B. The Department made a number of revisions to this Subsection based on comments from IPANM and NMOGA, as detailed in NMED Rebuttal Exhibit 1, pp. 68-69.

NMOGA and IPANM proposed to change the term "liquid unloading" to "manual liquid unloading" in Subsection A and throughout the rule where the term "liquid unloading" is cited. The Board should reject this proposal because it would restrict the type of unloading events covered under this Section. NMED testified that it intended to regulate both manual and automated liquid unloading events that result in venting of natural gas. NMED Rebuttal Exhibit 1, p. 68.

IPANM proposed to add language that this Section only applies in areas of the state specified in Section 20.2.50.2. The Board should reject this as unnecessary and redundant because Section 20.2.50.2 already expressly provides that all the requirements in Part 50 are only applicable to sources in the specified areas of the State. NMED Rebuttal Exhibit 1, p. 69. IPANM also proposes to add language that the emissions standards, monitoring, recordkeeping and reporting requirements in Section 20.2.50.117 only apply to the liquids unloading described in Section 20.2.50.117. The Board should reject this language as circular and redundant. *Id.*

B. Emission standards:

(1) The owner or operator of a natural gas well shall implement at least one of the following best management practices during the life of the well to avoid the need for venting of natural gas associated with liquid unloading:

(a) use of a plunger lift;

(b) use of artificial lift;

(c) use of a control device;

(d) use of an automated control system; or

(e) other control if approved by the department.

(2) The owner or operator of a natural gas well shall implement the following best management practices during venting associated with liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

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

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

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

NMED: Subsection B of Section 20.2.50.117 requires owners and operators of natural gas wells to implement at least one of several specified best management practices to avoid the need for venting of natural gas associated with liquid unloading. This Subsection also requires the use of certain best management practices to minimize emissions during venting associated with liquid unloading. These provisions are based on similar requirements in Colorado, Pennsylvania, and Wyoming. The Department made numerous revisions to its original proposal based on comments from NMOGA and IPANM, as detailed in NMED Rebuttal Exhibit 1, pp. 69-70.

[NMOGA's earlier edits in Paragraph (2) are not part of its final proposal.] The methods proposed by the Department are a selection of the technically feasible methods identified in the MAP Technical Report (NMED Exhibit 10), NMOGA's Methane Mitigation Roadmap (NMED Rebuttal Ex. 7), and EPA's Oil and Natural Gas Sector Liquids Unloading Processes (NMED Rebuttal Ex. 8).

NMED proposed revisions to this Subsection to provide a suite of available options to forestall the need for venting, as discussed in the three technical documents mentioned above, and control emissions during venting (blowdown) events. Owners and operators are given flexibility to choose an appropriate method for any given source that is subject to these provisions.

The Board should adopt NMED's proposal for the reasons stated in NMED Exhibit 32 pp. 93-96 and NMED Rebuttal Exhibit 1, pp. 69-70.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with liquid unloading:

(a) wellhead pressure;

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

(c) duration of venting to the storage vessel, tank battery, or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted during a venting event associated with a liquid unloading event.

(3) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.117 sets forth monitoring requirements for liquid unloading events, including monitoring well-head parameters and performing VOC volume and mass calculations during an unloading event. Owners and operators must also comply with the general monitoring requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32 pp. 93-96. [NMOGA's earlier proposal in Subsection C is not part of its final proposal.] NMED's proposed language provides flexibility regarding this requirement and owners and operators can estimate this flow rate. NMED provided guidance in the rule when the flow rate of vented gas cannot be monitored directly by using the maximum potential flow rate in the emission calculation. NMED Rebuttal Exhibit 1, p. 71.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date of the unloading event;

(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 estimated flow rate in the emission calculation);

(e) duration of venting to the storage vessel, tank battery, or atmosphere;

(f) a description of the best management practices used to minimize venting of VOC emissions during the life of the well and before and during the liquid unloading; and

(g) a calculation of the VOC emissions vented during a liquid unloading event based on the duration, calculated volume, and composition of the produced gas.

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

<u>NMED:</u> Subsection D of Section 20.2.50.116 sets forth recordkeeping requirements for liquid unloading events. Owners and operators are required to maintain records of well location and ID number, liquid unloading dates, wellhead pressure, vented gas flow rate (to the extend feasible), duration of venting event, VOC management practice used before and during liquid unloading, device used to control VOC emissions during unloading, and calculation of VOC emissions vented during unloading. The VOC calculation is based on the duration, volume, and mass of the VOC. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32 pp. 93-96, and NMED Rebuttal Exhibit 1, p. 71.

IPANM proposed to remove the requirement in Subparagraph D(1)(g) to record the type of control device or technique used to control emissions during an unloading event. The Board should reject this proposal. NMED testified that this is an essential recordkeeping requirement that requires owners and operators to affirmatively record the type of device or technique used to reduce emissions. Without such information the Department cannot know what, if any, control reduction methods were implemented. This would essentially make the requirement to control emissions during an unloading event unenforceable because it does not allow the Department to determine compliance with the emissions standards of this Section. NMED Rebuttal Exhibit 1, p. 71.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.117 NMAC - N, XX/XX/2021]

<u>NMED:</u> Subsection E of Section 20.2.50.117 specifies that owners and operators must comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 94-96.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.117

As described in NMED's rebuttal testimony, ERG estimated that installation of plunger lifts on wells requiring liquids unloading that currently do not employ this technology would result in reductions of 4,272 tpy of VOC, or 36% of the baseline VOC emissions. No estimates were available to quantify the reductions expected from implementation of the proposed best management practices requirements under Part 50. NMED Rebuttal Exhibit 1, pp. 96-97.

The ICF Economic Analysis estimated that costs associated with installation of a plunger lift include capital costs of $20,000 and operating costs of $2,400. In a 2011 report, EPA estimated that the payback period for installing a plunger lift could be from 1 to 8 years, depending on the value of natural gas and well-specific parameters. EPA has further found that the advantages of a plunger lift, in addition to reduced VOC and methane emissions, include increased productivity and reduced well maintenance, such as treatments to remove scale and paraffin. NMED Exhibit 32, pp. 97-98.

The Board should find that NMED's estimated costs associated with Section 20.2.50.117 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

<u>IPANM's proposed Section 117; from pp. 6-7 of its "redline" attachment</u>:

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: <u>Manual</u> liquid unloading operations resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. <u>Manual</u> Liquid unloading operations that do not result in the venting of any natural gas are not subject to 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 within two years of the effective date of this Part.

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 <u>manual</u> liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during venting associated with liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown or 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 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 reduce emissions during venting associated with a manual liquid unloading event:

(a) use of a plunger lift;

(b) use of artificial lift;

~~(c) use of a control device;~~

(d) use of an automated control system; or

(e) other practices ~~control~~ if approved by the department.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during venting associated with manual liquid unloading:

(a) wellhead pressure;

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

(c) duration of venting to the storage vessel, tank battery, or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC emitted during a venting event associated with a manual liquid unloading event.

~~(3) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.~~

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for manual liquid unloading:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date of the manual unloading event;

(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 vessel, tank battery, or atmosphere;

(f) a description of the management practice used to minimize venting of VOC emissions before and during the manual liquid unloading;

~~(g) the type of control device or control technique used to control VOC emissions during venting associated with the liquid unloading event;~~ and

(h) a calculation of the VOC emissions ~~vented~~ emitted during a manual liquid unloading event based on the duration, calculated volume, and composition of the produced gas.

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

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

<u>IPANM:</u> Section 117 applies to liquid unloading operations that include down-hole well maintenance events at a natural gas well. NMED Ex. 32 at 91 (Bisbey-Kuehn/Palmer Direct). Liquids unloading is an important process to maintain optimal production and maximize the production of the well. IPANM Ex. 2 at 9 (Davis Direct); NMED Ex. 32 at 91 (Bisbey-Kuehn/Palmer Direct). "Liquid loading begins when the gas velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow gas production to overcome the surface equipment and flow out of the wellbore." NMED Ex. 32 at 91 (Bisbey-Kuehn/Palmer Direct).

VOC emissions from manual liquid unloading operations occur "when the well is vented to the atmosphere to unload fluids or when the liquids are unloaded through atmospheric tanks and the gas mixed with the liquid is vented to the atmosphere." NMED Ex. 32 at 93 (Bisbey-Kuehn/Palmer Direct). IPANM supports the use of best management practices to reduce emissions associated manual liquids unloading. IPANM Ex. 2 at 7 (Davis Direct). IPANM, however, opposes the prescriptive nature of the lift methodologies in Section 117.B(3). Id.

IPANM and NMOGA both suggested limiting the applicability of this section to only those events that vent to the atmosphere. IPANM Ex. 1 at 5 (Proposed Rule Changes); NMOGA Appendix A1 at 25 (Smitherman Direct). EDF supported NMED's proposal in the original rule to require operators to reduce emissions during liquids unloading. EDF Ex. WW at 37 (Alexander Rebuttal). EDF stated that the methods suggested by NMED have been around for a significant amount to time and are both economically and technically feasible for installation and use. Id. at 37-38.

NMED agreed with a number of revisions proposed by NMOGA and IPANM. NMED Rebuttal Ex. 1 at 68 (Bisbey-Kuehn/Palmer Rebuttal). NMED disagreed with the inclusion of the term "manual" to describe the liquid unloading events as it is NMED's intent that this section cover both manual and automated liquid unloading events. Id. NMED rejected IPANM's proposal to remove the prescriptive paragraph 3 of 20.2.50.117.B, however, NMED added additional flexibility to this paragraph to allow operators to use a different control that meets the needs of their source. NMED Rebuttal Ex. 1 at 70 (Bisbey-Kuehn/Palmer Direct). NMED's changes included the addition of use of an automated control system as suggested by NMOGA. NMOGA Appendix A1 at 25 (Smitherman Direct); NMED Rebuttal Ex. 2 at 22 (Proposed Rule, Sept. 7, 2021).

NMED testified about emissions that occur from well liquid unloading. Tr. Vol. 9, 3131:2-13 (Bisbey-Kuehn). NMED also testified that the basis of the rule requirements being from Colorado Regulation 7, Pennsylvania General Permits 5 and 5A and Wyoming Permitting Guidance. Tr. Vol. 9, 3131:19-3132:16 (Palmer). IPANM testified about the requirement for using a control device on a storage tank during a manual well unloading is a significant safety concern. Tr. Vol. 9, 3143:5-12 (Davis). IPANM also testified that the best management practices listed in Paragraph 3 of Section 117.B are better listed in Paragraph 1, as these are measures that are taken during the life of the well and not necessarily something that is employed as a control strategy for manual liquids unloading. Tr. Vol. 9, 3145:1-10 (Davis).

IPANM also requested that NMED revise the recordkeeping requirements to reflect an estimated flow rate during a manual unloading event rather than a maximum potential flow rate. Tr. Vol. 9, 3145:24-3146:7 (Davis). This is because the whole purpose of a manual unloading event is because a well is not performing at its maximum potential, so a maximum potential flow rate would overestimate emissions. Tr. Vol. 9, 3146:5-7 (Davis). NMED agreed with IPANM that the list of methodologies in Paragraph B.3 be moved to B.1. Tr. Vol. 9, 3150:17-22 (Bisbey-Kuehn). EDF testified in support of the move of the list of best management practices, but reiterated that it did not want the list to be completely removed. Tr. Vol. 10, 3219:15-330:6 (Alexander).

NMED also agreed to use the estimated flow rate, instead of the maximum potential flow rate, in the Recordkeeping Requirements Section. Tr. Vol. 9, 3150:24-3151:3 (Bisbey-Kuehn). EDF also testified that it supports the use of artificial lifts as a way to increase production, enhance well economics and reduce emissions. Tr. Vol. 10, 3221:4-9 (Alexander).

The Board should find that the language as proposed in the September 16, 2021, version of the rule for 20.2.50.117 NMAC and modified by IPANM is appropriate as it provides sufficient flexibility for operators to choose the most appropriate methodology to employ during a manual unloading event.

NMOGA supports applying the rule only to manual unloading events that result in venting of gas and encouraging smart technology: The Department's proposal for natural gas well liquid unloading under 20.2.50.117 NMAC only apply to unloading events that result "in the venting of natural gas." Mr. Smitherman testified that the rule should be modified to recognize that only manual liquid unloading events that result in venting of gas to the atmosphere are covered, since there is no benefit to emissions reductions to apply the requirements to activities that do not cause emissions. NMOGA Exhibit A1:25:1-46. The Board should find that limiting section 20.2.50.117 NMAC to hydrocarbon liquid unloading events that cause emissions is supported by substantial evidence and the weight of evidence.

The Department's proposal includes automatic control systems as an option for controlling hydrocarbon liquid unloading events. Mr. Smitherman testified that these systems help minimize venting volumes by detecting the end of an unloading event and triggering the actuation of the valve to send gas back to the facilities and sales. NMOGA Exhibit A1:25:29-36. Mr. Smitherman testified further that allowing use of the automated control system will encourage development of these smart systems. The Board should find that encouraging use of this proven technology is prudent and supported by substantial evidence and the weight of evidence. Smitherman testimony, NMOGA Exhibit A1:25:41-46.

CEP opposes IPANM's revisions: EDF witness Tom Alexander testified the best management practices proposed in NMED's proposed Section 117 are all effective, cost effective, and technologically practicable methods to reduce emissions during liquids unloading. EDF Ex. WW at 2. In his experience, these are not only standard industry practices, but have been in the production engineering toolkit for decades. EDF Ex. WW at 2-3; 10 Tr. 3216:25-3218:6, -3220:15-3221:9. In Mr. Alexander's experience, artificial lift is a preferred method of keeping a well unloaded and producing efficiently.

And in the end, a well that is produced properly will have a higher estimated ultimate recovery. 10 Tr. 3231:5-3232:1.

The EIB should reject IPANM's proposed revisions. IPANM's revisions significantly weaken the proposed rule and will result in less emissions reductions. EDF Ex. WW, p. 4. IPANM proposes to limit the applicability of the liquids unloading provision to manual unloading events only. This would significantly narrow the applicability of the rule by completely ignoring emissions from artificial lift technologies used during non-manual unloading activities. While resulting in far fewer emissions than manual unloading, the use of artificial lift technologies to unload a well nevertheless results in some emissions. EDF Ex. WW at 4. Mr. Alexander strongly disagrees with IPANM's proposal to strike the use of a control device as a listed method to reduce emissions during unloading events for two reasons. EDF Ex. WW at 4. First, the methods to reduce emissions during unloading listed by NMED are all feasible and economic. 10 Tr. 3220:21-3221:9; EDF Ex. WW at 4. Second, because the rule only requires "at least one of the following best management practices," the operator is free to select the method best suited to the particular well. 10 Tr. 3251:11-3252:13.

Finally, Mr. Alexander strongly disagrees with the revision to apply only to manual unloading since artificial lift methods, such as plunger lifts, can result in some minimal emissions. EDF Ex. WW at 5.

20.2.50.118 GLYCOL DEHYDRATORS:

NMED: **Description of Equipment or Process**

A glycol dehydrator is a liquid desiccant system for the removal of water from natural gas and natural gas liquids. Triethylene glycol is the most commonly used desiccant in these systems. Failure to remove water results in formation of crystalline hydrates at the high pressures used to transport the gas. Hydrates can block pipelines, jam valves, and can generally wreak havoc on pipeline equipment and instrumentation. In the glycol dehydrator, the triethylene glycol absorbs water and VOCs from the gas. The triethylene glycol is then regenerated by heating it to release the absorbed compounds. The reboiler from a large glycol dehydrator can discharge more than one hundred tons per year of

VOCs, including benzene, toluene, ethylbenzene and xylene (collectively, "BTEX"). For a full description of glycol dehydrators, see NMED Exhibit 32, pp. 98-100.

Control Options for Glycol Dehydrators

There are a number of options available to owners and operators of glycol dehydrators for controlling emissions. Still vent and flash tank emissions can be routed at all times to the reboiler firebox (for use as fuel), a condenser, combustion control device, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or a natural gas gathering pipeline. See testimony regarding control devices (Section 20.2.50.115) for a discussion of VRUs. A combustion control device is either a flare or an enclosed combustor. A condenser uses water, air, or another coolant to lower the temperature of the vent gases and cause the vapors to condense from gas to liquid phase where they can be collected. Costs were estimated for condensers and combustion control devices because existing cost estimates are readily available and are more universally applicable. Costs for other control options are more site-specific and standardized cost estimating methods are not readily available. NMED Exhibit 32, pp. 100-101.

Rule Language

The proposed requirements in Section 20.2.50.118 are based on similar requirements for dehydrators adopted by Colorado and Pennsylvania, as well as federal regulations. A full discussion of the basis for these requirements is in NMED Ex. 32, pp. 102-103.

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

<u>NMED:</u> Section 20.2.50.118 applies to glycol dehydrators with a PTE equal to or greater than two tons per year of VOC and are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. The Board should adopt this proposal for the reasons stated in NMED Ex. 32, pp. 98, 101-104.

[NMOGA's earlier proposal in Subsection A limiting applicability to those dehydrators with an actual annual average flowrate of greater than 3 MMscfd throughput is not part of its final proposal.] The throughput threshold originally proposed by NMOGA is an exemption threshold present in the federal NESHAP regulations for emissions from glycol dehydrators at 40 C.F.R. Part 63, Subpart HH. The AQCA expressly allows the Board to impose more stringent requirements than federal regulations to address rising ozone concentrations in the State. A 3 MMscfd throughput threshold may have been appropriate for applicability of the NESHAP, which targets hazardous air pollutants, but it is not appropriate for an ozone precursor rule, which is targets reductions of VOC emissions. NMED rejected NMOGA's proposed exemption threshold because VOC emissions from dehydrators vary primarily by composition of the gas, and less by throughput amount. Even dehydrators with throughputs less than 3 MMscfd can still have significant associated VOC emissions. In any event, those units with low VOC emissions are addressed by the PTE thresholds in Subsection B. NMED Rebuttal Ex. 1, p. 72.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) no later than two years after the effective date of this Part. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank (if present) upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following 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 VOC emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas pipeline;

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

(c) the still vent and flash tank emissions shall not be vented

directly to the atmosphere during normal operation.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy of VOC.

<u>NMED:</u> Subsection B of Section 20.2.50.118 sets forth emission standards for glycol dehydrators. Owners and operators of existing dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% no later than two years after the effective date of the rule. Owners and operators of new glycol dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank by at least 95% upon startup. For both new and existing dehydrators, the combustion device (if used) must meet a minimum 98% destruction efficiency. Still vent and flash tank emissions must be routed to a control device, a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline. If a VRU is used, the VRU must be operational at least 95% of the time, resulting in a minimum combined capture and control efficiency of 95%. The requirements of Section 20.2.50.118 cease to apply when the actual annual VOC emissions from a new or existing glycol dehydrator are less than 2 tpy VOC. The Department made a number of revisions to this Subsection based on comments from IPANM and NMOGA, as detailed in NMED Rebuttal Ex. 1, pp. 72-73. The Board should adopt the Department’s proposal for the reasons stated in NMED Ex. 32, pp. 101-105.

<u>NMOGA proposes changes to paragraph B(3) (b):</u>

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that reinjects the vapor into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the ~~facility~~ <u>controlled equipment</u> is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent, <u>which shall supersede any inconsistent requirements in 20.2.50.115 NMAC.</u> The VRU shall be installed, operated, and maintained according to the manufacturer’s specifications; and….

<u>NMOGA:</u> Ms. Bisbey-Kuehn testified that she was agreeable to the change about

superseding inconsistent requirements to address the inconsistency between the allowed 95% downtime and the redundant VRU requirement in 20.2.50.115 NMAC. Bisbey-Kuehn Testimony, Tr. 7:2322:2-6. See also Textor rebuttal testimony, NMOGA Exhibit 46: 14:16-26. Ms. Textor testified that the term "vapor" should replace "natural gas" because the off gases from a flash tank have a lower methane content than natural gas would have. Ms. Textor also testified that the redundant VRU concept must be clarified for purposes of glycol dehydrators. Rebuttal Testimony of Marise Textor, NMOGA Exhibit 46:15:39-46 – 16:1-16. This language clarifies that the redundant VRU requirement does not supersede the allowed 5% downtime.

C. Monitoring requirements:

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

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(4) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

<u>NMED:</u> Subsection C of Section 20.2.50.118 sets forth monitoring requirements for glycol dehydrators. Owners and operators are required to conduct an annual extended gas analysis to determine the composition of the gas being processed by the dehydrator and must to use this gas analysis to calculate the uncontrolled and controlled emissions from the dehydrator. This calculation will demonstrate whether the 95% emission reduction requirement is met. Owners and operators are required to inspect dehydrators and control devices or processes semi-annually to ensure integrity of the equipment and that the equipment is being operated as initially designed and in accordance with manufacturers specifications. Monitoring events must be date and time stamped. Owners and operators complying with Section 20.2.50.118 through the use of a control device must comply

with the monitoring requirements in Section 20.2.50.115. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

[NMOGA's earlier proposed revisions to allow use of a representative gas analysis in the emissions calculations in lieu of unit-specific inlet analyses do not appear in its final proposal.] Estimated emissions from a source should be based on the most accurate information available. A representative gas analysis may be appropriate for a well that has yet to be constructed, but the requirement in this Section is for an annual calculation for all dehydrators in operation whether they qualify as a "new" or "existing" source under this rule. Calculations based on the composition of the actual gas being processed by the subject source are by definition more accurate, and the Department requires extended gas analyses for its permits. NMED Rebuttal Exhibit 1, p. 73.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) unique identification number and dehydrator location (latitude and longitude);

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

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and unique identification number of the control device or process the emissions are being routed;

(f) time and date stamp, including GPS of the location, of any monitoring;

(g) results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(h) a copy of the glycol dehydrator manufacturer specifications.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

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

<u>NMED:</u> <u>Subsection D – Recordkeeping Requirements</u>

Subsection D of Section 20.2.50.118 sets forth recordkeeping requirements for glycol dehydrators. Owners and operators are required to keep records of equipment throughput data, emissions calculations and supporting documentation, inspection results, and manufacturer information. These records must be maintained onsite and submitted to the Department upon request. The recordkeeping requirements of Section 20.2.50.115 apply where a control device is being used to comply with the requirements of Section 20.2.50.118. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.118 NMAC - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.118 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 102-105.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.118

ERG estimated that the controls required under Section 20.2.50.118 would reduce emissions by 1,865 tpy, leading to a 46.2% overall reduction in VOC emissions from dehydrators. The emission reduction analysis is detailed in NMED Exhibit 32, pp. 103-104, and NMED Exhibit 77 – Dehydrators Reductions and Costs Spreadsheet.

ERG estimated the annualized cost for installing and operating a condenser to be $21,560 and the annualized cost for installing and operating a combustor to be $10,583. The total annualized costs of adding condensers to the 199 dehydrator units was estimated at approximately $4,300,000 per year, while the total annualized costs of adding combustors to the 199 dehydrator units was estimated at approximately $2,100,000 per year. Costs for both condensers and combustion controls were presented for information purposes, although for each dehydrator the owner of operator would install either a condenser or a combustor, not both. A full explanation of ERG's cost analysis for glycol dehydrators is presented in NMED Exhibit 32, pp. 104-105. The Board should find that NMED's estimated costs associated with Section 20.2.50.118 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.119 HEATERS:

NMED:

Description of Equipment or Process

Natural gas-fired heaters are used throughout the oil and gas production and processing sectors to prevent equipment from freezing and being blocked by the formation of ice or hydrates; to improve the separation of well products into oil, water, and natural gas; and in certain types of process equipment, such as glycol dehydrators. A full description of heaters and their use in oil and gas operations is provided in NMED Ex. 32, pp. 105-106.

Control Options

NO_X emissions from heaters may be controlled through combustion modifications that reduce the formation of NO_X; through the use of add-on controls to control NOx in the exhaust stack; or through a combination of combustion modifications and add-on controls. Combustion modifications include low-NO_X burners (LNBs), ultra-low NO_X burners (ULNBs), and flue gas recirculation (FGR). Add-on controls include selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). In addition to combustion modifications and add-on controls, many regulatory programs require periodic equipment tune-ups and good combustion practices to keep heaters operating at maximum efficiency in order to reduce emissions. Good combustion practices are also important in controlling CO and VOC emissions. NMED Ex. 32, p. 107.

Rule Language

The proposed NO_X and CO limits are based on limits adopted by the State of Pennsylvania and EPA for natural gas fired combustion units. The NO_X limits are the same as those in the Pennsylvania GP-5 requirements for natural gas-fired combustion units. *See* NMED Exhibit 37 at Section L, p. 24. The CO limits are the same as those in the federal regulations at 40 C.F.R. 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters* ("NESHAP Subpart DDDDD"). *See* NMED Exhibit 80. CO is commonly regulated as a surrogate for VOC or organic hazardous air pollutants (HAPs) because CO is a good indicator of incomplete combustion and VOC and HAP are products of incomplete combustion. EPA used CO limits instead of hazardous air pollutant limits in NESHAP Subpart DDDDD because it "concluded that

CO, which is less expensive to test for and monitor, is appropriate for use as a surrogate for non-dioxin organic HAP." *Id.*, at p. 52210. NMED Exhibit 32, p. 108.

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

NMED: Section 20.2.50.119 applies to natural gas-fired heaters with a rated heat input equal to or greater than 20 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. In response to comments from IPANM proposing to raise the applicability threshold for heaters to 50 MMBtu/hr, NMED agreed to revise its original applicability threshold for heaters NMED presented costs associated with the requirements for heaters in Part 50 in the ERG – Heaters Reductions and Costs NO2 Spreadsheet at NMED Exhibit 82.

As explained in NMED's direct testimony at NMED Exhibit 32, these costs were taken from the EPA 1993 ACT document at NMED Exhibit 53, and were based on a 17 MMBtu/hr heater, which is the smallest heater size for which cost data is available. A review of the available heater data in the costing spreadsheet indicates only 2 of the 82 heaters that would be subject to the rule are 10 MMBtu/hr heaters. The EPA 1993 ACT document indicates the cost effectiveness for a 17 MMBtu/hr heater operating at 90% capacity is $4,742/ton NOx, which NMED considers reasonable. A 10 MMBtu/hr heater would have lower emissions than a 17 MMBtu/hr heater, which would result in a higher cost effectiveness using the same annualized costs as a 17 MMBtu/hr heater. Based on the increased costs for the smallest heaters subject to the rule, NMED proposed to revise the applicability threshold to 20 MMBtu/hr, which is larger than the heater size used in the cost calculations and supports more cost-effective reductions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 105-110, and NMED Rebuttal Exhibit 1, pp. 75-76.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 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**	**400**
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	**30**	**400**

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than three years after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

NMED: Subsection B of Section 20.2.50.119 sets forth emissions standards for natural gas-fired heaters. Existing and new natural gas-fired heaters are limited to 30 ppmvd NO_X at 3% oxygen, and 400 ppmvd CO at 3% oxygen. Existing heaters must comply with these standards no later than three years after the effective date of Part 50, while new heaters must comply upon startup. NMED revised the emissions limits for CO from 300 ppmvd to 400 ppmvd, and raised the timeline for compliance for existing heaters from one year after the effective date to three years after the effective date based on comments from NMOGA. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 107-110, and NMED Rebuttal Ex. 1, pp. 73-75.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing 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 specifications;

(iii) inspecting the AFR controller and ensuring it is

calibrated and functioning properly, if present;

(iv) optimizing total emissions of CO consistent with the NO_x requirement and manufacturer specifications, and good combustion 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 Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer 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 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load in a prior test plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring event, the owner or operator shall date and time stamp the event, and the required monitoring data entry shall be made in accordance with this Part.

(5) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.119 sets forth monitoring requirements for natural gas-fired heaters. Owners and operators are required to conduct emission testing for NO_X and CO within 180 days of the applicable compliance date, and at least every two years thereafter. The equipment must be inspected, maintained, and repaired in accordance with the manufacturer's specifications at least once every two years after the applicable compliance date. An owner or operator may deviate from the specified periodic testing procedures by submitting a written request to use an alternative procedure to the Department at least 60 days prior to performing the periodic testing, but must receive written approval from NMED prior to conducting periodic testing using an alternative procedure. The owner or operator must comply with the general monitoring requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Ex. 32, pp. 107-110, and NMED Rebuttal Ex. 1, pp. 73-75. [NMOGA's earlier proposed revisions to provide for testing are not in its final proposal.] The rule allows for testing at highest achievable load ***or*** within ten percent of one hundred percent peak load. Heater tests already have the option to verify emissions only at the highest achievable capacity. NMED Rebuttal Exhibit 1, p. 74.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) unique identification number and location (latitude and longitude) of the heater;

(2) summary of the complete test report and the results of periodic testing;

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date and time stamp, including GPS of the location, of the inspection, testing, maintenance, or repair conducted;

(b) name of the person(s) conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

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

NMED: Subsection D of Section 20.2.50.119 sets forth recordkeeping requirements for natural gas-fired heaters. Owners and operators are required to maintain records of the following information: location of the heater; summary of the complete test report and results of periodic testing; and inspections, testing, maintenance, and repairs. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 107-110.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.119 NMAC - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.119 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 107-110.

Estimated Costs and Emission Reductions Resulting from Section 20.2.50.119

ERG estimated total reductions of 216 tons per year of NO_X for an overall reduction of 16% from the baseline of 1,355 tpy NOx. ERG estimated a total annualized cost to meet the proposed emission limits of approximately $684,341 at a cost effectiveness of $3,162 per ton of NO_X reduced. A full description of ERG's costs and emission reductions analyses for Section 20.2.50.119 is provided in NMED Exhibit 32, pp. 108-110 and NMED Exhibit 82 – Heaters Reductions and Costs NO2 Spreadsheet.

The Board should find that NMED's estimated costs associated with Section 20.2.50.119 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

NMED: **Description of Equipment or Process**

Hydrocarbon liquid transfers involve moving hydrocarbon liquid from a transfer vessel to a storage tank, or from a storage tank to a transfer vessel. There are three primary methods of vessel loading: splash loading, submerged fill pipe (a pipe inserted into a tank to facilitate loading) and bottom loading. For splash loading, the fill pipe is lowered only part way into the vessel, and the resultant splashing generates VOC emissions. In submerged fill pipe loading, the fill pipe will extend close to the bottom of the vessel. In bottom loading, a permanent fill pipe is connected at the bottom of the vessel. Both submerged fill pipe loading and bottom loading reduce the generation of VOC emissions. During the transfer of hydrocarbon liquids from one vessel to another, the remaining VOC-containing vapor from the previous contents of the vessel will also be vented as the vessel is filled. NMED Exhibit 32, p. 110.

Control Options

The options typically used to reduce VOC emissions from hydrocarbon liquid transfers are similar those for storage tanks, and include: (1) routing emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – "route to a process" (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or (2) routing emissions from the storage vessel to a combustion device. In practice, many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks. NMED Exhibit 32, p. 111.

In addition to these control options, emissions from hydrocarbon liquid transfers are also commonly controlled using vapor balancing service, whereby the vapors in the tanker truck or railcar are routed back into the storage vessel as the liquids in the storage vessel are emptied into the receiving vessel (the truck or railcar). Vapor balancing requires a pipe or hose connected between the storage vessel and the receiving vessel prior to transfer. Bottom loading and submerged filling are additional best management practices used to reduce emissions from hydrocarbon liquid transfers. *Id.*

Rule Language

The proposed control and operational requirements are based on requirements in Colorado's Reg. 7, Section II.C.5 (NMED Exhibit 39); Pennsylvania GP-5 and GP-5A (NMED Exhibits 37 and 38); Utah's Rule R307-504 – Oil and Gas Industry: Tank Truck Loading, (NMED Exhibit 83); and Wyoming's presumptive BACT for oil and gas truck loading operations, found in the Wyoming Permitting Guidance (NMED Exhibit 40). As described in NMED Exhibit 32, these other states require various best management practices and/or the use of control devices such as enclosed combustors to control emissions from hydrocarbon liquid transfers. NMED Exhibit 32, pp. 113-115.

A. Applicability: Hydrocarbon liquid transfers located at existing well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC within two years of the effective date of this Part. Hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 NMAC on the schedule specified in Paragraph 1 of Subsection B of 20.2.50.123 NMAC. Hydrocarbon liquid transfers located at new well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants,

or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC upon startup. The following facilities and operations are not subject to the requirements of this Section:

(1) Any facility connected to an oil sales pipeline that is routinely used for hydrocarbon liquid transfers;

(2) Well sites, standalone tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations not connected to an oil sales pipeline that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year; and

(3) Transfers of hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC.

NMED: Section 20.2.50.120 is applicable to hydrocarbon liquid transfer operations (or hydrocarbon liquid loading) at well sites, standalone tank batteries, gathering and boosting stations with one or more controlled storage vessels, natural gas processing plants, and transmission compressor stations. Transfer operations at existing facilities have two years from the effective date to comply with this Section, and transfers at new facilities must comply upon startup. The Department included the extended timeline for existing facilities based on comments from Oxy USA and NMOGA. NMED Exhibit 32, pp. 110-116; NMED Rebuttal Exhibit 1, p. 76.

NMED is also proposing to include a revised schedule for a subset of hydrocarbon liquid transfer operations, namely, transfer operations at existing gathering and boosting stations without any controlled storage vessels. This proposal is based on concerns raised by NMOGA regarding how the requirements of Section 20.2.50.120 interact with the requirements for storage vessels in 20.2.50.123. NMED agrees with the proposed language; see NMOGA's justification for this proposal below.

Paragraphs (1), (2), and (3) provide an offramp from the requirements of Section 20.2.50.120 for facilities that are connected to an oil pipeline routinely used for hydrocarbon liquid transfers, for facilities that load out hydrocarbon liquids to trucks fewer than 13 times per year, and for transfers from a transfer vessel to a storage vessel subject to the emissions standards of 20.2.50.123. NMED added these paragraphs in response to comments by NMOGA and CDG. NMED Rebuttal Exhibit 1, p. 76.

The Board should adopt the Department's proposal for the reasons stated above and in NMED Exhibit 32, pp. 110-116, and NMED Rebuttal Exhibit 1, p. 76.

[CDG's earlier proposal to exclude hydrocarbon liquid transfers with an uncontrolled PTE less than two tpy of VOC emissions is not part of its final proposal.] NMED proposed revisions to exclude facilities that are connected to an oil sales pipeline, and at facilities that load out hydrocarbon liquids fewer than 13 times per calendar year. Those two provisions are sufficient to address facilities with a small number of loadout events. See NMED Rebuttal Exhibit 1A, p. 1-2.

[NMOGA's proposed changes to Section A have already been incorporated into NMED's proposal above.]

NMOGA: To ensure the "technical practicability and economic reasonableness" of standards under 20.2.50.121 NMAC, the Board should finalize several changes proposed by the Department and NMOGA. These include excluding liquid transfers involving produced water, excluding production facilities and associated tank batteries delivering liquids directly to pipelines, excluding sources that perform less than 13 loadouts per year, allowing semiannual inspections at unstaffed locations, and applying the extended implementation deadline under 20.2.50.123.B.(1) (rather than the 2-year deadline under 20.2.50.120 NMAC) to tanks used in hydrocarbon liquid transfers at gathering and boosting stations without controls. These changes are needed to eliminate costly measures that have no demonstrable ozone benefit and adjust implementation to reflect current supply chain challenges.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-five percent, when transferring hydrocarbon liquid from a storage vessel to a tanker truck or tanker railcar for transport. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) An owner, operator, or personnel conducting the hydrocarbon liquid transfer using vapor balance shall:

(a) transfer the vapor displaced from the transfer truck or railcar being loaded back to the storage vessel being emptied via a pipe or hose connected before the start of the transfer operation. If multiple storage vessels are manifolded together in a tank battery, the vapor may be routed back to any storage vessel in the tank battery;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) inspect connector pipes, hoses, couplers, valves, and pressure relief devices for leaks;

(d) check the hydrocarbon liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Connector pipes and couplers shall be inspected and maintained to ensure there are no liquid leaks.

(4) Connections of hoses and pipes used during hydrocarbon liquid transfers shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(5) Liquid leaks that occur shall be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

NMED: Subsection B of 20.2.50.120 sets forth emission standards for hydrocarbon liquid transfer operations. The Department incorporated numerous revisions to its proposal in this Subsection based on comments from NMOGA, as detailed in NMED Rebuttal Exhibit 1, p. 77.

Paragraph (1) requires owners or operators to control VOC emissions by at least 95% via vapor balance, vapor recovery, or a control device. If using a combustion control device, it must have a minimum design combustion efficiency of 98%. Paragraph (2) specifies the requirements that owners or operators using vapor balance must comply with, including the following: displaced vapor must be loaded back to the vessel being emptied via pipe or hose connected before the start of the transfer operation; transfer cannot begin until the vapor collection and return systems are properly connected; connector pipes, hoses, couplers, valves and pressure relief devices must be inspected for leaks; hydrocarbon liquid and vapor line connections must be checked for proper connection prior to commencing the transfer operation; and the transfer equipment must be operated at a pressure that is less than the pressure relief valve setting of the receiving vehicle or vessel.

Paragraphs (3) through (5) specify that, for all transfer operations, connector pipes and couplers must be inspected for liquid leaks, hose and pipe connections must be supported on drip trays to collect any leaks, and the materials collected must be returned to the process or properly disposed of. Liquid leaks must be cleaned and disposed of in a manner that minimizes emissions to the atmosphere, and the material collected must be returned to the process or properly disposed of.

Paragraph (6) provides that owners and operators using a control device to comply with the emission standards of Section 20.2.50.120 must comply with the control device requirements in Section 20.2.50.115.

The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 110-116, and NMED Rebuttal Exhibit 1, p. 77.

NMOGA proposes an edit to NMED's prior draft in B(3):

(3) Connector pipes and couplers shall be inspected and maintained free of ~~in a leak-free condition~~ liquid leaks.

C. Monitoring requirements:

(1) The owner, operator, or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. At least once per calendar year, the inspection shall occur during a transfer operation. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation, or measures must be implemented to mitigate leaks until the necessary repairs are completed.

(2) The owner or operator of a hydrocarbon liquid transfer operation controlled by a control device must follow manufacturer specifications for the device.

(3) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(5) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.120 sets forth the monitoring requirements for hydrocarbon liquid transfer operations. The Department incorporated numerous revisions in this Section based on comments from NMOGA, see NMED Rebuttal Exhibit 1, p. 78.

Paragraph (1) requires owners, operators, or their designated representatives to visually inspect the transfer equipment for leaks monthly at staffed locations, and semi-annually at unstaffed locations. At least once per calendar year, the required inspection must occur during a transfer operation. If leaks are discovered, they must be repaired prior to the next transfer operation, or leaks must be mitigated until necessary repairs are completed.

Paragraph (2) requires operations that employ a control device to follow the manufacturer's specifications for the device. Paragraph (3) requires that an owner or operator using vapor balance, vapor recovery, or a control device to minimize VOC emissions must comply with the monitoring requirements contained in Section 20.2.50.115. Paragraph (4) requires monitoring events under Section 20.2.50.20 to be date and time stamped according to the requirements of Part 50. Paragraph (5) requires owners and operators to comply with the general monitoring requirements in Section 20.2.50.112. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 112-116, and NMED Rebuttal Exhibit 1, p. 78.

Oxy USA proposes removing the requirement that at least one inspection per calendar year under Paragraph (1) must be conducted during a transfer operation. The Department did not agree with this proposal. Ms. Kuehn testified that an inspection during a transfer operation is important component of the inspection requirements in this Section. The Board should reject Oxy USA's proposal for the reasons stated in NMED Exhibit 32, pp. 112-116; and NMED Rebuttal Ex. 1, p. 78; and Tr. Vol. 1962:1-8.

[NMOGA's proposed edit (specifications) has already been incorporated by NMED.]

<u>Oxy proposes a deletion in C(1):</u>

(1) The owner, operator, or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations to ensure that hydrocarbon liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. ~~At least once per calendar year, the inspection shall occur during a transfer operation.~~ Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation, or measures must be implemented to mitigate leaks until the necessary repairs are completed.

<u>Oxy:</u> The final version of the proposed rule includes a requirement to inspect hydrocarbon liquid transfer equipment once per year during a transfer. This requirement

will be difficult to implement at unstaffed locations. Third-party lease operators often conduct transfers at these unstaffed locations and Oxy USA does not always receive notification of a proposed transfer with enough time to ensure that a representative is present for the inspection. As Mr. Holderman noted, "… the majority of the leaks that happen during transfer tend to happen because of operator error, not because the equipment is leaking. And so if we're going to go to the effort [to] institute a rule to minimize emissions, it needs to be around a protocol that allows us to more frequently inspect [the third-party lease operators] that are making those connections rather than an arbitrary once a year test [of] that connection environment." Hearing Transcript at TR-1972:19-25 and TR-1973:1-4. Oxy USA does not believe that an annual inspection during transfer will provide sufficient benefit to offset the logistical issues associated with its implementation. Rather, Oxy USA believes there are more effective measures – targeted at the personnel making the transfers – that can be taken to reduce emissions.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the following:

(a) the location of the facility;

(b) if using a control device, the type, make, and model of the control device;

(c) the date and time stamp, including GPS of the location, of any inspection;

(d) the name of the person(s) conducting the inspection;

(e) a description of any problem observed during the inspection; and

(f) the results of the inspection and a description of any repair or corrective action taken.

(2) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

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

<u>NMED:</u> Subsection D of Section 20.2.50.120 sets forth recordkeeping requirements for hydrocarbon liquid transfer operations. Owners or operators conducting transfer operations must maintain records of the location of the facility; if using a control device, records of the type, make and model; date and time stamp, including GPS location, of any

inspection; and other records relating to required inspections and repairs. Records must also be maintained of the annual total hydrocarbon liquid transferred and annual VOC emissions from each site. On an annual basis, the owner or operator is required to create a company-wide record summarizing the total annual hydrocarbon liquid transferred and the total annual calculated VOC emissions. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 112-116, and NMED Rebuttal Exhibit 1, pp. 78-79.

[NMOGA's earlier proposals in Paragraph (1) are not part of its final submittal.] The record of the control device used is necessary to determine compliance with this Section. Otherwise, there is no record documenting the type of control utilized to meet the emissions standards of this Section. NMED agreed to change the language requiring a record of the location of the storage vessel to requiring a record of the location of the facility. NMED Rebuttal Exhibit 1, p. 78. [NMOGA's earlier proposal in Paragraph (2) is not part of its final proposal.] NMED Exhibit 32 provided the data regarding liquid transfers, and the estimated emissions reductions and costs for the proposed requirements. The records required in Subsection D of 20.2.50.120 are necessary for determining compliance with the emission standards of this Section, and are consistent with requirements for these types of operations in other states. NMED Exhibit 32 at pp. 113-116; NMED rebuttal Exhibit 1, p. 79.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.120 NMAC - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.120 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32 at p. 113-116.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.120

ERG estimated the total emissions reductions from Section 20.2.50.120 at 4,263 tpy of VOC for an overall reduction of 86.8%. The total annualized costs of installing controls at these facilities were estimated at $2,283,886, resulting in an overall cost effectiveness of $536/ton of VOC controlled. A full explanation of ERG's emission reductions and cost analyses is provided NMED Exhibit 32, p. 115 and NMED Exhibit 84 – Transfers Reductions and Costs Spreadsheet. The Board should find that NMED's estimated costs associated with Section 20.2.50.120 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

IPANM supports a limit of 13 hydrocarbon liquid load out events to trucks per year.

NMOGA: The Board should adopt the Department's latest redline with minor revisions because the proposal incorporates several changes consistent with the Board's obligation to consider the "Technical Practicability and Economic Reasonableness" of its rules. Prior versions of proposed 20.2.50.120 NMAC applied to production facilities and associated tank batteries delivering liquids directly to pipelines and produced water transfers. Mr. Smitherman credibly testified that regulating such sources presents technical challenges, would not be cost-effective, and would not result in significant emissions reductions. NMOGA Exhibit A1, 26:1-46 – 27:1-12. The Department's latest proposal adjusts the rule to address this testimony, and NMOGA urges the Board to concur with these conclusions.

The Department's latest proposal exempts facilities from section 20.2.50.120 NMAC that perform less than 13 loadouts per year. 20.2.50.120.A NMAC. This exemption is based on the testimony of Mr. Smitherman, who testified that hydrocarbon liquid transfers are a function of event frequency, that sites that perform liquid transfer infrequently have a low emitting potential, and that the required controls are not warranted on a cost-per-ton basis for low-emitting operations. NMOGA Exhibit A1, 27:15-26. NMOGA urges the Board to find these changes are supported by the record. The Department's current proposal requires industry to visually inspect hydrocarbon liquid transfer equipment monthly at staffed locations and semiannually at unstaffed locations. 20.2.50.120.C.1 NMAC. These requirements reflect the testimony of Mr. Smitherman who testified to the logistical challenges and administrative burden of conducting inspections more frequently, particularly when sites are unmanned or remotely located. NMOGA Exhibit A1, 28:37-46. The monthly and semiannual inspection frequencies reflect a reasonable strategy for evaluating compliance with hydrocarbon liquid transfer requirements, and NMOGA urges the Board to concur.

NMED's latest proposal also requires hydrocarbon liquid transfers to be controlled within 2 years of the effective date. For sources that control transfers by routing vapors to a storage vessel, this effectively supersedes the multiyear phase-in schedule proposed under 20.2.50.123.B.(1) NMAC for storage vessels. Unlike the 2-year deadline under 20.2.50.120 NMAC, section 123 requires that 30% of existing storage vessels be controlled by January 1, 2025, 35% by January 1, 2027, and the remainder by January 1, 2029. *See* 20.2.50.123.B.1(a)-(c) NMAC. Some gathering and boosting sites route vapors back to existing tanks without existing controls during transfer events and do so on a large scale. These operators cannot practically retrofit their entire inventory of storage vessels with combustion controls within two years for the same reason that owners and operators of storage vessels generally need a phase-in period under 20.2.50.123.B.(1) NMAC. Mr. Holderman testified that steel shortages, component shortages, labor shortages, limited manufacturing capacity, and other supply chain issues make meeting these demands within 2 years infeasible. Tr. 9:2899:4-25 - 9:2900:1-9. The Board should direct that hydrocarbon liquid transfers at existing gathering and boosting stations (including associated tank batteries) without any controlled storage vessels are subject to the requirements of 20.2.50.120 on the schedule in 20.2.50.123.B.(1) NMAC.

Finally, in NMED's May 6, 2021 proposal, oil and gas owners and operators were required to conduct vapor tightness testing on tanker trucks or tanker rail cars used for hydrocarbon liquid transfers. In the July 28, 2021, proposal, NMED removed these provisions. The Department explained the reason for this change: "Tanker trucks and tanker rail cars transporting hydrocarbon liquids are not subject to Part 50 and were not analyzed by the Department during the development of the requirements in Part 50. The Department did not intend to impose testing and inspection requirements on equipment not subject to Part 50." NMED Direct Exhibit 32, at 11. NMOGA agrees with the removal of these standards. Under 49 U.S.C. § 5125(b), the vapor tightness standards are preempted because they would have imposed more stringent testing requirements on hazardous material containers than federal hazardous material transportation law. Similarly, under 49 U.S.C. § 10501(b), the standards are federally preempted as they relate to rail shipments because they would have had the effect of managing or governing rail transportation, an area of regulation reserved to the federal government.

20.2.50.121 PIG LAUNCHING AND RECEIVING:

NMED: **Description of Equipment or Process**

Natural gas passing through gathering pipelines contains VOCs, as well as other impurities such as water and carbon dioxide. As this gas passes through the pipeline system, any change in temperature or pressure may result in development of natural gas condensates in a liquid phase in the pipeline. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of these pipelines, operators insert a device called a “pig” into the pipeline which is swept along the pipeline by the pressure of the existing gas flow. Condensate and any other solid or liquid materials that have formed in the pipeline are pushed along in front of the pig until it reaches a “receiver,” at which point the pig is isolated in an offshoot pipeline segment and any condensates and liquids are drained out of the pipeline. The pig is then reinserted and swept along the next segment of pipeline. Pigs may also be used to create physical separation between different fluids flowing through the pipeline, for cleaning the internal surfaces of the pipelines, inspection of the condition of pipeline walls, and recording information relating to pipelines (e.g., size, location). NMED Exhibit 32, pp. 116-17. Emissions to the atmosphere may occur at both the pig launcher and receiver when the pipeline is opened to insert or extract the pig. Emissions from pigging operations depend on factors such as the launcher or receiver volume, pipeline pressure, the amount of liquid trapped in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition. *Id.* at 117.

Control Options

Emissions from pigging operations may be controlled through process modifications, through the use of add-on controls such as a flare, enclosed combustor or thermal oxidizer, or by using a VRU. EPA has identified several process modifications to minimize emissions from pigging operations. These are discussed in detail in NMED Exhibit 32, pp. 118-19, and NMED Exhibit 85 – MarkWest Consent Decree.

Rule Language

The proposed requirements for pigging operations are based on Pennsylvania GP-5 and GP-5A, and Ohio’s General Permit 21.1 for Title V and non-Title V pigging operations

("Ohio General Permits"). NMED Exhibit 32, p. 120.

NMOGA and Kinder Morgan propose to remove Section 20.2.50.121 in its entirety, or alternatively to limit the applicability of the requirements to within a facility's property boundary.

The Department's proposed requirements in Section 20.2.50.121 are based on similar requirements in Pennsylvania GP-5 and GP-5A, and Ohio's General Permits, as discussed in NMED Exhibit 32 at p. 119-120. Colorado also recently proposed regulations targeting emissions from pigging operations. NMED Rebuttal Exhibit 1, p. 79. Thus, other states have found it worthwhile and appropriate to regulate these operations. NMED's direct testimony explained that NMED has data on at least 10 facilities with these operations, and that this rule would reduce VOC emissions by at least 24 tpy. NMED Exhibit 32, p. 120. NMED also testified that they know the universe of affected operations is larger than what the data shows, and therefore the emissions reductions will be greater than what the modeling shows. *See* NMED Exhibit 32, p. 121; NMED Rebuttal Exhibit 1, pp. 79-80. For these reasons, the Board should find that some level of regulation for pigging operations is warranted, and rejects industry's proposals to entirely remove this provision from Part 50. However, NMED did propose significant revisions to this Section to incorporate most of the changes proposed by the industry parties, as discussed below. NMED Rebuttal Exhibit 1, pp. 79-80.

<u>NMOGA:</u> Regarding Pig Launching & Receiving, 20.2.50.121 NMAC, and Well Workovers, 20.2.50.124 NMAC, the record does not demonstrate that pig launching and receiving and well workover standards will contribute demonstrably to ensuring attainment or maintenance of the primary ozone standards. Their adoption is not supported by the record and would imperil the legal soundness of the rule. If the Board decides to proceed anyway, despite the negligible ozone benefit, then the requested redlines should be made to reduce the burden.

To evaluate the impacts of the proposed rule on ozone, NMED commissioned a photochemical model. The purpose of the model was to assess the impacts of proposed Part 50 controls on ozone concentrations in New Mexico. The testimony of NMOGA witness Dennis McNally characterized the model results as follows: The ozone air quality benefits of the proposed rule are quite modest, and what impacts the rule does have are primarily the result of the NOx control measures. Additional controls on oil and gas VOC emissions are not an effective means of controlling ambient ozone levels in New Mexico, except for possibly in a very limited area in northeastern San Juan County. NMOGA Exhibit A4, at 16. NMED's expert Ralph Morris, who conducted the analysis on behalf of NMED, concedes this point. See, e.g., Tr. 2:397:1-20. To provide context on a per-ton basis, Mr. Morris testified that an increase or decrease of 670 tons of NOx emissions per year one way or another would have "no material effect on ozone results." Vol. 2, 381:1-12; 398:9-14. Mr. McNally similarly testified that increases or decreases in VOC emissions in excess of a thousand tons of VOC per year would have no demonstrable impacts on ozone concentrations. Vol. 2, 494:22-25 – 495:1-5.

According to NMED's own witnesses, standards under 20.2.50.121 NMAC for pig launching and receiving and standards under 20.2.50.124 NMAC for workovers will not reduce emissions in amounts exceeding these thresholds. As such, if these standards are not adopted and the anticipated reductions are added back to the inventory, the increase will not have an impact on ozone attainment or maintenance. Ms. Bisbey-Kuehn testified that NMED estimates overall emissions reductions of 22.9 tons of allowable VOC emissions from implementation of the proposed standards for pig launching and receiving under 20.2.50.121 NMAC. Tr. 9:3053:5-11. Ms. Bisbey-Kuehn testified this number did not account for all emissions because the Department's emissions inventory is not complete. Id. But even if the emissions were underestimated by a factor of 45, they would not move the ozone needle according to the testimony of Mr. McNally and Mr. Morris. Moreover, because the Department's pig launching and receiving standards have no federal counterpart, these standards are more stringent than existing federal law. As such, they trigger the protectiveness evaluation in NMSA 1978, § 74-2-5.G. A statement that the requisite information to justify the rule is not available does not qualify as "substantial evidence" of greater protectiveness. The Board should reject this proposal as it provides no demonstrable benefit to ozone attainment and maintenance.

Similarly, NMED provided no emissions estimates to support the implementation of best management practices for well workovers under proposed 20.2.50.124 NMAC. According to NMED witness, Mr. Palmer, "emissions estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED equipment data." Vol. 9, 3101:19-23. The workover proposal has no federal counterpart and is thus subject to the heightened protectiveness evaluation in NMSA 1978, § 74-2-5.G. Because the record contains no evidence that VOC emissions from workovers have any impact on ozone, the NMED has not provided substantial evidence to support adoption of the standard.

If the Board ultimately adopts these standards against the weight of the evidence cited above, NMOGA urges the Board to also adopt the modifications advocated for by NMOGA, which reduce the burden in light of the negligible emissions benefit. [NMOGA's proposed redlines are below each section. See alternative SOR 103-107.]

A. Applicability: Individual pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership or control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

<u>NMED:</u> Section 20.2.50.121 applies to pipeline pig launcher and receiver operations with a PTE equal to or greater than one tpy VOC located within the property boundary of, and under common ownership and control with, well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. NMED made significant revisions to its original proposal based on comments from NMOGA, Kinder Morgan, and CDG, including proposing an applicability threshold of one tpy VOC, limiting applicability only to pig launching within the property boundary of the listed facilities under common ownership and control with those facilities. *See* NMED Rebuttal Exhibit 1, p. 80. The Board adopts the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 116, 119-123; and NMED Rebuttal Exhibit 1, p. 80.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launcher and receiver operations shall capture and reduce VOC emissions from pigging operations by at least ninety-five percent within two years of the effective date of this Part. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of

ninety-eight percent.

(2) The owner or operator conducting an affected pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to minimize emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that minimizes emissions to the atmosphere to the extent practicable; and

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

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to an individual pipeline pig launching and receiving operation if the actual annual VOC emissions of the launcher or receiver operation are less than one tpy of VOC.

(4) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

NMED: Subsection B of 20.2.50.121 outlines the emissions standards for pig launcher and receiver operations. Owners and operators of affected pigging operations are required to capture and reduce VOC emissions by at least 95% within two years of the effective date of Part 50. In addition, owners and operators must employ a suite of best management practices and equipment modifications during pigging operations to minimize or prevent emissions. These emission standards cease to apply where actual annual VOC emissions from an individual pipeline pig launching and receiving operation are less than 1 tpy VOC. Owners and operators complying with the requirements of Section 20.2.50.121 through the use of a control device must comply with the requirements of 20.2.50.115. NMED agreed to numerous revisions to this Subsection based on comments from NMOGA and CDG, including reducing the capture and control efficiency from 98% to 95%, extending the compliance deadline to two years from the effective date of Part 50, and owners and operators to minimize emissions rather than prevent them. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 119-123; and NMED Rebuttal Exhibit 1, pp. 80-81.

NMOGA proposes to replace the word "prevent" with "minimize" in B(2)(b). See Textor rebuttal testimony, NMOGA Exhibit 46: 10:7-27. Ms. Textor testified that emissions cannot be prevented, they can only be minimized. The rule's language should reflect that.

CDG also proposes to replace the word "prevent" with the word "minimize" in B(2)(b), changing it for consistency with (B)(2)(a) and (B)(2)(c).

NMOGA proposes an addition to section B(4):

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC. An owner or operator complying through use of a portable control device shall install the device consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC.

NMOGA: Regarding applicability, NMOGA directs the Board to Textor rebuttal testimony, NMOGA Exhibit 46:3-5. Ms. Textor testified that the rule should only apply to those individual onsite pig launchers or receivers with emissions greater than or equal to one ton per year VOC to improve cost effectiveness.; Textor rebuttal testimony, NMOGA Exhibit 46:6:34-44, 7:1-14. Ms. Textor testified that it is not feasible to install a pipeline pressure storage tank, a vapor recovery system on a depressurization vessel, and a compressor at off-site locations. Similarly, facilities to control emissions such as flares or combustors would virtually never be available at offsite locations and would need to be brought in as portable equipment for each pigging event, further escalating costs. Regarding emission standards, NMOGA directs the Board to Textor rebuttal testimony, NMOGA Exhibit 46: 8:29-45, 9:1-32. Ms. Textor testified that a emissions reduction of 98% would be difficult to achieve, because devices only achieve that level under steady state conditions. Efficiency in practice will be lower, so the rule should require no more than a design destruction efficiency of 95% control efficiency.

C. Monitoring requirements:

(1) The owner or operator of an affected pig launching and receiving site shall inspect the equipment for leaks using AVO, RM 21, or OGI on either:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

(b) prior to the commencement and after the conclusion of the pig

launching or receiving operation, if less frequent.

(2) The monitoring shall be performed using the methodologies outlined in Subsection (C) of 20.2.50.116 NMAC as applicable and at the frequency required in Paragraph (1) of Subsection (C) of 20.2.50.121 NMAC. The monitoring shall be performed when the pig trap is under pressure.

(3) An owner or operator complying with Paragraphs (1) or (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

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

NMED: Subsection C of Section 20.2.50.121 sets forth monitoring requirement for affected pig launcher and receiver operations. Owners and operators must inspect equipment for leaks using the identified monitoring methods on a monthly basis of pigging operations occur monthly or more frequently, and before commencement and after conclusion of pigging operations if less frequent. Monitoring must be performed using the methodologies outlined in Subsection C of Section 20.2.50.116. Owners and operators complying with the emission standards in Section 20.2.50.121 through the use of a control device must comply with the monitoring requirements in 20.2.50.115.

Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. NMED made several revisions to the requirements in this Subsection based on comments from NMOGA and Kinder Morgan including adding AVO as an option for monitoring; revising the monitoring frequency to match the frequency of operations; removing the requirement to monitor according to Section 20.2.50.112 and substituting monitoring according to Sections 20.2.50.116 and 20.2.50.121; removing the requirement to monitor the amount and type of liquid cleared; and other edits that clarify the intent of this Section. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, pp. 119-23.

Kinder Morgan supports: Infrequent pigging in the transmission segment coupled with the low VOC content natural gas present in the transmission segment results in very low VOC emissions from transmission pigging operations. Rebuttal NOI, Ex. XVI at 1. Kinder Morgan presented data demonstrating that annual VOC emissions from certain of the company's compressor stations in 2020 and 2019 were less than 0.04 tpy per compressor station. Id. at 1; see also Id., Attachment BB. It would be unreasonable to require transmission compressor station operators to monitor pigging units monthly when they are pigging every 2 to 5 years. 20.2.50.121.C.(1)(b) NMAC addresses this concern by requiring monitoring prior to and after the conclusion of pigging operations, if pigging operations at a site occur less frequently than once per month. Kinder Morgan supports this clarification, and respectfully requests that the Board adopt it into the final rule.

<u>NMOGA adds support for C(1):</u> Regarding C(1)(b), see Textor rebuttal testimony, NMOGA Exhibit 46: 11:31-41. Ms. Textor testified that monthly inspections and inspections before and immediately after launch are more cost effective and likely as effective in reducing emissions.

<u>NMOGA proposes an addition to Section C(3):</u>

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC. <u>A portable control device shall be installed consistent with manufacturer's specifications and is not subject to the requirements of 20.2.50.115 NMAC.</u>

<u>NMED opposes NMOGA's revision:</u> NMOGA proposes in Paragraph (3) to exempt portable control equipment from the requirements of Section 20.2.50.115. The Department does not agree with this proposal and maintains that it is important for the requirements of Section 20.2.50.115 apply to all control devices, whether portable or permanent. The Board should reject NMOGA's proposal. It is unclear whether NMOGA is proposing to exempt all portable control devices from the requirements in Section 20.2.50.115, or just those used in pigging operations. Regardless, NMOGA's testimony provides no principled basis for exempting only portable control devices used in pigging operations, and acceptance of NMOGA's proposed language risks creating a major loophole in the rule for portable control devices. NMED believes that the monitoring requirements in Section 20.2.50.115 are appropriate for all control devices whether as well as permanent control devices and are critical for ensuring that the control devices are operating properly and controlling emissions as intended. Absent periodic monitoring of control device operation and performance, there is no way for the owner or operator or the Department to determine if the equipment is operating properly. NMED Rebuttal

Exhibit 1, p. 81.

If the Board is inclined to adopt NMOGA's proposal exempting portable control equipment from the monitoring requirements in Section 20.2.50.121, NMED requests that the Board adopt the following language:

(3) *An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a non-portable control device shall comply with the monitoring requirements in 20.2.50.115 NMAC. A portable control device <u>used to comply with Paragraph (1) of Subsection B of 20.2.50.121 NMAC</u> shall be installed consistent with manufacturer's specifications and is not subject to the <u>monitoring</u> requirements in Section 20.2.50.115.*

D. Recordkeeping requirements: In addition to complying with the recordkeeping requirements in 20.2.50.112 NMAC, the owner or operator of an affected pig launching and receiving site shall maintain a record of the following:

(1) the pigging operation, including the location, date, and time of the pigging operation;

(2) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE;

(3) date and time of any monitoring and the results of the monitoring; and

(4) the type of control device and its make and model.

<u>NMED:</u> Subsection D of Section 20.2.50.121 sets forth recordkeeping requirements for pig launcher and receiver operations. Owners and operators must maintain records of location, date, and time of the pigging operation; the data and methodology used to estimate the actual emissions and the PTE; date and time of monitoring events and results of the monitoring; and information on any control device used. Owners and operators must comply with the general recordkeeping requirements of Section 20.2.50.112. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 119-23, and NMED Rebuttal Exhibit 1, pp. 81-82.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.121 NMAC - N, XX/XX/2021]

<u>NMED:</u> Subsection E of Section 20.2.50.121 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board should adopt

this proposal for the reasons stated in NMED Exhibit 32, pp. 119-23.

Estimated Emissions Reductions from Section 20.2.50.121

Based on the NMED Equipment Data, ERG identified 10 facilities with pigging operations. However, this is not a complete inventory of pigging operations because they are most often located within other facilities and are not identified separately in NMED's permitting and facility databases. Further, pigging operations are also not quantified separately in the data from EPA's Greenhouse Gas Reporting Program for Petroleum and Natural Gas Systems, 40 C.F.R. 98, Subpart W. Of the 10 facilities determined from NMED data, four facilities have five pigging operations with allowable VOC emissions equal to or greater than 1 tpy VOC each. Based on the applicability threshold of 1 tpy VOC, these operations would be required to implement reductions of 98% pursuant to Paragraph (1) of Subsection B of Section 20.2.50.121. Total allowable VOC emissions from these five operations are 24.1 tpy, so the total reductions would be 23.6 tpy VOC based on the 98% control requirement. Total emissions from the pigging operations with emissions below the 1 tpy VOC 98% control applicability threshold are 1.6 tpy VOC, resulting in an overall control efficiency of 92%. NMED Exhibit 32, p. 121.

Estimated Costs for Section 20.2.50.121

EPA Fact Sheet No. 505 provides an estimate of the costs and benefits of capturing liquids and gas from pigging operations. *See* NMED Exhibit 87. According to that document, best management practices for recovery of liquids and gas would require separating pigged liquids from the gas, storing the liquids temporarily at gathering system pressure, and then sending them to a low-pressure storage tank. These liquids (recovered at pipeline pressure) would flash and vent light hydrocarbon gases from the storage tanks. The flash emissions would be recovered by installing a dedicated vapor recovery system on the vessel where the liquids are depressurized. The recovered gas would then be sent to the sales line. This process would reduce emissions and add more gas to the sales line. NMED Exhibit 32, pp. 121-22.

The cost estimates presented in EPA Fact Sheet No. 505 would be appropriate for launching and receiving stations located adjacent to processing plants or pipeline compressor stations that may already have the equipment needed for recovery on-site. In a presentation titled "Vapor Recovery and Gathering Pipeline Pigging" at the July 2008

Producers and Processors Technology Transfer Workshop in Midland, Texas, EPA provided an example from one Natural Gas STAR Program partner that purchased equipment and implemented this process. *See* NMED Exhibit 89, Slide 35. This company installed a dedicated vapor recovery unit with an electric compressor at an installed cost of $24,000 and an annual operating cost of $40,000 (mostly for electricity). However, based on the value of the condensate recovered, the payback period for the same installation was estimated to be approximately 4 months. *Id.* at 122.

Alternatively, companies may choose to use a temporary skid-mounted flare to meet the control standard for remote pigging operations or pigging operations where the existing infrastructure does not support product recovery. EPA Natural Gas STAR Program's PRO Fact Sheet No. 904, *Install Flares* (2011), provided costs to install and operate a flare at a remote site. *See* NMED Exhibit 90. The estimated implementation cost of a skid-mounted flare is $21,000 and the operating costs per year are $3,000, plus any fuel needed for a pilot light. If the flare were portable, it could be moved to sites on an as-needed basis, with additional cost for transport and set-up added for each pigging operation. *Id.* The Board should find that NMED's estimated costs associated with Section 20.2.50.121 are reasonable and necessary to advance the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

NMED: **Description of Equipment or Process**

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves. Natural gas-powered pneumatic controllers use natural gas as motive force to operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate in oil and natural gas production and processing. NMED Ex. 34 (EPA CTG). Pneumatic controllers may also be powered by compressed air instead of natural gas. NMED Ex. 32, pp. 122-23. Pneumatic controllers are used to control multiple processes based on a sensed process parameter, such as liquid level in a tank or oil-water separator. Pneumatic controllers can be used as emergency shutoff devices, to regulate flow or liquid levels, or as temperature and pressure regulators. NMED Ex. 10 (MAP Technical Report), *Id.*

VOC and methane emissions occur from natural gas-powered pneumatic controllers when the pressurized gas is directed to atmosphere after the control action is performed. *See* NMED Exhibit 34 (EPA CTG). *Id.* Pneumatic pumps are used to inject chemicals into the wellbore, to circulate glycol in cold climates, and to move liquids from one place to another (sump pumps). Pneumatic pumps range from chemical injection pumps which may inject a few tablespoons of corrosion inhibitor to a well bore, to large diaphragm pumps which move thousands of gallons of product per hour from one tank to another, to pump water out of containment areas after wet weather, or for heat trace to protect pipes from freezing in cold weather. *See* NMED Exhibit 34 (EPA CTG); NMED Exhibit 10 (MAP Technical Report). NMED Exhibit 32, p. 123.

VOC and methane emissions occur from pneumatic pumps when the pressurized natural gas used to drive the pumping action is released to atmosphere after being used for the pumping action. The quantity of VOCs emitted is dependent on the type of pump employed and the concentration of VOCs in the gas stream. *See* NMED Exhibit 10 (MAP Technical Report). *Id.* at 124.

Depending on their intended use, natural gas-driven pneumatic controllers and pumps are available in a variety of designs, but may be characterized by their bleed rate, which is a measure of how much natural gas is used to operate the pneumatic controller or pump, and therefore the emissions from the pneumatic controller or pump. Continuous bleed pneumatic controllers have a continuous supply of natural gas to the process controller (e.g., liquid level control, temperature control, or pressure control) and emit or "bleed" natural gas continuously while the natural gas pressure in the controller is balanced against the process condition (e.g., liquid level, temperature, and pressure), and compared with the associated process set-point. Continuous bleed controllers may either be low bleed (with a bleed or emissions rate less than or equal to 6 standard cubic feet per hour (scfh), or high bleed (with a bleed or emissions rate greater than 6 scfh). Intermittent pneumatic controllers do not vent continuously, but instead release gas only when they open or close a valve, or as they throttle (i.e, adjust) gas flow. The bleed rate from these controllers depends on the amount of gas vented per actuation (i.e., each opening or closing of a valve or adjustment of gas flow) and the frequency of actuation. Zero bleed pneumatic controllers do not bleed natural gas at all. They are self-contained units that release gas to a downstream pipeline. NMED Exhibit 32, pp. 124-25; NMED Exhibit 91 – EPA Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Pneumatic Devices: Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel as part of the President's Climate Action Plan: a Strategy to Reduce Methane Emissions* (April 2014) ("EPA 2014 O&G Pneumatic Devices Report").

Control Options for Pneumatic Controllers and Pumps

There are several ways to reduce emissions from pneumatic controllers, including replacing high bleed controllers with low bleed or zero bleed models, using instrument air rather than natural gas to drive controllers, and using non-gas-driven controllers such as mechanical or electric controllers, including solar-powered controllers. Regular maintenance and proper adjustment of pneumatic controllers can also be used to minimize emissions by repairing leaks and optimizing the amount of gas needed to operate the device. Options for reducing emissions from pneumatic pumps include using instrument air rather than natural gas to drive pumps, using non-gas-driven pumps, such as electric pumps, or routing emissions to a control device or process. NMED Exhibit 32, p. 125; NMED Exhibit 92 – EPA Office of Air and Radiation, *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry* (October 2006).

Rule Language

As an initial matter, the Department notes that on January 19, 2022, counsel for NMOGA circulated proposed revisions to the Department's proposed language in Section 20.2.50.122 that NMOGA intends to include in its final proposal to the Board. Counsel for NMOGA stated the intent of these revisions was not to change the stringency of any requirements in Section 20.2.50.122, but rather to make the rule more workable in the oilfield. The Department has reviewed these proposed revisions and agrees that they are an improvement to its current proposed language in Section 20.2.50.122. Therefore, while the Department was unable to include these revisions in its final proposal due to insufficient time, the Department supports adoption of those changes by the Board.

<u>General Approach</u>

Proposed Part 50 is based on similar rules for new and existing pneumatic controllers and pneumatic pumps in Colorado Reg. 7, Sections I.K, III.C, and III.D. NMED Exhibit 32, pp. 128-131; NMED Exhibit 39. However, the Department's proposal differs from the

Colorado rules in the fundamental approach it takes; specifically, the Department's proposal regulates pneumatic controllers on the basis of controller counts, while the Colorado rules regulate on the basis of total historic liquids production.

In their direct testimony, NMOGA, IPANM, Oxy USA, GCA, CDG, and Kinder Morgan (collectively, "Industry Parties") proposed adoption of the regulatory approach to pneumatic controllers adopted in February of 2021 by Colorado as part of its Regulation 7. At the hearing, NMOGA stated its support for the Department's proposed approach. *See* Tr. Vol. 7, p. 2109:1 – 2110:16 (Smitherman).

The eNGO parties initially supported the Department's proposed approach in their direct testimony, with proposals to shorten the compliance deadlines, increase the number of devices that must be non-emitting for all facilities covered under this Section, and add new additional and maximum percent non-emitting device requirements. However, in their rebuttal testimony and at the hearing, the eNGO Parties changed course and put forth a joint proposal with Oxy USA ("Joint Proposal") advocating the Colorado approach. At the hearing, EDF's witness Dr. McCabe testified that the retrofit schedule in NMED's proposal is slower than Colorado's rule and would result in a lower number of retrofits than the Joint Proposal. Witnesses for the Department disagreed with this assertion and pointed out that Dr. McCabe did not present any data or analysis to support his assertion, nor did he take into account the higher number of controllers that need retrofitting in New Mexico as compared to Colorado. *See* Tr. Vol. 7, 2237:23 – 2238:12, 2240:5 – 2242:25, 2247:4 – 2256:13. Ms. Kuehn further explained that the Joint Proposal was not fully developed and was missing significant rule language that would be necessary for implementation, such as the method to determine total historic percentage of liquids produced at facilities. *See* Tr. Vol. 7, 2238:13 – 2239:6.

The Board should find that the Colorado approach is not appropriate for New Mexico for the reasons stated in NMED Rebuttal Exhibit 1, p. 83-90. Colorado has regulated pneumatic devices under Colorado Reg. 7, Part D, Section III since 2009. These provisions include emissions reduction requirements for both new and existing pneumatics located within the Denver Front Range (DFR) nonattainment area. Colorado Reg. 7 also has requirements for pneumatics located outside of the DFR nonattainment area that were constructed between May 1, 2014 and May 1, 2021 which require the use of zero bleed pneumatics for facilities with commercial line power, and low bleed pneumatics where line power is not available and it is not technically or economically feasible to retrofit the devices. Part D, Section III was revised in 2017 to include specific requirements for inspections and leak detection and repairs of natural gas driven pneumatics. *See* Colorado Reg. 7, Part D, Section III.F *Pneumatic Controller Inspection and Enhanced Response*. These requirements were initially applied only to nonattainment areas, but were expanded in 2019 to cover other areas of the state.

The result of these prior regulatory efforts is that Colorado, through Reg. 7, has already achieved significant reductions in the overall number of high-bleed pneumatics and their associated emissions, and has implemented a robust inspection and monitoring program to oversee the proper operation of these devices. Thus, Colorado had already reduced emissions by replacing large numbers of high bleed pneumatic controllers and reducing emissions from pneumatic controller malfunctions, before it established the newer targets for non-emitting controllers based on company-wide production. Colorado's new requirements in its recently-adopted rules were developed based on the pre-existing regulatory requirements in that state and in the context of emissions reductions that have already been achieved under those requirements.

The Department's proposal, while premised on a similar but more straightforward concept than that used by Colorado for the new Reg. 7 requirements, does not have the similar advantage of building regulatory provisions off of emission reductions achieved by past regulatory efforts. As a result, the proposed provisions in Section 20.2.50.122 will likely achieve higher emission reductions from pneumatic controllers by targeting reductions in the overall number of emitting controllers, rather than by reducing the fraction of controllers represented by a certain percentage of overall production. At the same time, the Department's proposed approach will also address emissions from pneumatic controller malfunctions by establishing monitoring requirements for all pneumatic controllers to ensure they are functioning properly and emitting only when they should be.

NMED also attempted to design a simpler regulatory scheme for pneumatics than that provided under Colorado's rule, while still providing important flexibilities and workable timeframes. NMED accomplished this by allowing for important flexibility so that owners and operators can prioritize the sites and/or controllers that are retrofitted; providing a reasonable compliance timeline for existing sources; allowing for the use of emitting units in certain instances when natural gas driven units are required for safety or process purposes; providing an offramp from the requirements if owners and operators achieve a 75% non-emitting total controller count by January 1, 2025; and allowing owners and operators of units remaining after January 1, 2027 that are not cost effective to retrofit to submit a cost analysis and request a waiver of the retrofit requirements for those remaining units for approval by the Department.

The Department also chose a different approach to addressing economic impacts on small operators than Colorado. Rather than exempting low producing wells from regulatory requirements, as Reg. 7 does, NMED proposed scaled back regulatory requirements to provide regulatory relief for small operators through the small business facility definition. NMED's proposed approach is directly tied to a company's size and revenue, while Colorado Reg. 7 provides a blanket exemption based on average per well production, regardless of company size or revenue. This approach is problematic in New Mexico because it would exempt 269 out of the 324 well operators who have well production, and would exempt 30,200 wells (or 63% of wells) from the nonemitting controller requirements, thereby significantly undermining the purpose of the rule. *See* Tr. Vol. 7, 2243:1 – 2244:5.

The Board should find that NMED's proposed approach is more appropriately designed to provide relief tailored to small companies, without giving an across-the-board exemption for low producing wells which would compromise the fundamental goal of the proposed rule which is to achieve meaningful emissions reductions from oil and gas operations for the benefit of public health and the environment.

<u>NMOGA:</u> The Board should adopt NMED's proposed 20.2.50.122 NMAC (with minor revisions) because it requires reasonable but significant VOCs reductions from pneumatic controllers. NMOGA has proposed minor revisions, which the Department has reviewed and agreed with in concept, to improve implementation. These revisions clarify replacement requirements at existing facilities, clarify that compliance is set based on the tables, set forth a compliance methodology for determining compliance on January 1, 2024, 2027 and 2030, and provide greater certainty in handling controllers necessary for

safety and process reasons. The Board should reject proposals by other stakeholders to increase the stringency of pneumatics requirements because increasing stringency is unnecessary and, in many respects, impractical.

NMED's proposal requires all new natural gas-driven pneumatic controllers to have an emission rate of zero and a specified percentage of existing controllers to be non-emitting according to the schedule in proposed 20.2.50.122.B(3) NMAC. The proposal ultimately requires anywhere from 80 to 90% of controllers at well sites, tank batteries, and gathering and boosting stations to be non-emitting by January 1, 2030, and 98% of pneumatic controllers at transmission compressor stations and gas processing plants to be non-emitting by January 1, 2030. The proposal also requires new pneumatic diaphragm pumps located at natural gas processing plants to be non-emitting; new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power to be non-emitting; existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power to be non-emitting within two years; and certain pneumatic diaphragm pumps to be controlled by 95% where non-emitting technology is unavailable.

Other stakeholders object to the Department's pneumatic controller proposal primarily because it is different than Colorado's approach. While Colorado requires phaseout of pneumatic controllers on a production basis, New Mexico has applied a phaseout based on controller count. As Ms. Bisbey-Kuehn and Mr. Palmer explained, Colorado's approach is not appropriate for New Mexico. See generally, Tr. 7:2025:20-25 - 2027:1-15. Colorado has been regulating pneumatic controllers since 2009, and it has extensive infrastructure and administrative resources in place necessary to administer a program like Colorado's. Palmer Testimony, Tr. 7:2022:19-23; Bisbey-Kuehn Testimony, Tr. 7:2026:12-22. This is not the situation New Mexico finds itself in, as the state is regulating pneumatic controllers for the first time through proposed Part 50. Bisbey-Kuehn testimony, Tr. 7:2027:4-9. Unlike Colorado, New Mexico does not have the benefit of building the pneumatics program on top of emissions reductions already achieved by past regulatory efforts. Tr. 7:2022:19-23. The current proposal recognizes the status of the industry in New Mexico while requiring leaps forward to achieve significant emissions reductions. To the extent other stakeholders have espoused a production-based approach, it should be rejected for these reasons. Bisbey-Kuehn testimony, Tr.7:2028:4-13; Smitherman testimony, Tr. 7:2109:5-18.

In addition to requesting a production-based approach, other stakeholders propose measures to increase the stringency of the proposal. These measures would require owners and operators to achieve a fixed increase in the percentage of non-emitting controllers rather than attain a fixed point, require gas driven controllers at gas processing plants or transmission compressor stations to be converted to non-emitting within six months, accelerate the timeline so that all retrofits occur by 2025 rather than 2030, and remove the early action incentive in NMED's proposal. The rationale provided for these changes boils down to Colorado took a similar approach, so New Mexico should too. For the reasons outlined above, New Mexico is not Colorado, and the approach taken by another jurisdiction with different challenges and opportunities has little bearing on what's right for New Mexico. These requirements are often not technically or economically feasible and place strains on both the companies and supply chains. Smitherman testimony, Tr. 7:2109:14-7:2110:4. In addition, the only concrete evidence offered by Dr. McCabe for the six-month proposal was that natural gas processing plants were able to achieve this within 6 months in Colorado. McCabe testimony, Tr. 7:2076:14-17; Smitherman testimony, Tr. 7:2108:11-23. But as Dr. McCabe conceded and other witnesses noted, natural gas processing plants are large facilities with electric power that are relatively few in number and were not caught up in the pandemic's supply chain snarls. McCabe testimony, Tr. 7:2076:14-17. There is no compelling evidence in the record that a faster transition is possible and a lot of testimony why it is not given New Mexico's starting point and pandemic impacts.

Requiring retrofit at gas processing plants and transmission compressor stations within six months is also infeasible and unnecessary. Multiple witnesses with direct experience designing systems, planning retrofits, and grappling with current supply chain issues testified that this proposal is unrealistic. See, e.g., Tr. 7:2108:11-23; 2214:14-18; 2283:1-8; 2284:9 – 2285:25. Requiring phaseout to be completed by 2025 similarly presents logistical challenges. More importantly, as Mr. McNally testified, "The earlier imposition of VOC controls would have little impact on ozone levels in NM." NMOGA Exhibit 45, at 8.

Finally, these proposals should be rejected because NMED is requiring owners and operators to apply leak detection and repair measures to pneumatic controllers and pumps, a measure that significantly reduces the urgency of phaseout. NMED Rebuttal Exhibit 23, 20.2.50.116.C NMAC. Multiple witnesses testified that there are "significant emissions from malfunctioning gas-powered pneumatic controllers" and that applying LDAR to these devices would reduce emissions from these malfunction events. See, e.g., Tr. 7:60:6-9; 7:2224:8-24. If these malfunctioning devices are being identified and repaired, then New Mexico has less to gain by hastening their replacement. Tr. 7:2275:4-14. Because NMED's original pneumatics proposal did not contemplate imposing LDAR on pneumatic controllers, its cost-per-ton analysis did not consider emissions reductions attributable to LDAR. See NMED Exhibit 95. Consequently, when NMED adopted the pneumatic LDAR proposal, it should have updated its cost-per-ton analysis to include consideration of the LDAR costs and tons reduced before calculating the phase out costs and tons reduced, which would be less. Eliminating this error significantly decreases the cost-effectiveness of the retrofit requirements and counsels against increasing the stringency of the proposal.

While NMOGA is supportive of NMED's LDAR proposal, there are some changes that are needed to make it more workable. In suggesting these changes, NMOGA is not trying to change the stringency of the program, just make it more workable and clearer in application. First, all the discussions of the pneumatics program were premised upon units being subject either to Table 1 or Table 2 in 20.2.50.122.B.(3). The compliance methodology in paragraph (4)(b), however, applies to all pneumatic controllers and does not distinguish between the tables. NMOGA believes this is a drafting oversight as only sources subject to each Table should be assessed for that table. NMOGA has proposed language to address this oversight in the redline below and attached. After discussion between NMOGA and NMED counsel, NMOGA understands that NMED agrees that its proposal was meant to apply on a "table" basis and agrees with the concepts set forth in the NMOGA redline.

Second, both NMED and NMOGA have discussed the importance of pneumatic controllers "necessary for safety and process reasons," which NMED has proposed to exclude from the program upon a written demonstration. See 20.2.50.122.B.(4)(b)(i), D.(6); Kuehn testimony, Tr. 7:2041:1-5. While all parties likely agree with Ms. Kuehn that it would be "ideal" if these units were identified prior to the start of the program, the reality is that it won't happen. To protect both the ability to maintain these units and the phase out schedule, NMOGA proposes to rename the initial "total controller count" used to determine the phase out requirements as the "total historic controller count" so that neither it nor the phase out requirements applicable to an owner/operator are affected by subsequent identification of controllers necessary for safety or process reasons. NMOGA understands that NMED agrees with this concept as well.

Third, and most importantly, the rule does not provide how compliance with the phase out schedule will be demonstrated on the January 1, 2024, January 1, 2027, and January 1, 2030 compliance dates. It is clear from the testimony of all parties that even though Table 1 and Table 2 are phrased "Total Required Percentage of Non-Emitting Controllers by [date]" that the real focus is on replacing natural gas driven controllers with non-emitting ones or eliminating the natural gas driven controllers entirely, without replacement. Both replacement and elimination achieve the goal of reducing emissions. For purposes of demonstrating compliance on January 1, 2024, 2027 and 2030, NMOGA thus proposes that owners/operators will track the number of emitting controllers subject to each table, calculate a percentage of emitting controllers by dividing that total by the total historic controller count for that table, multiply by 100 to make a percent, and then subtract that percent from 100, which gives the "Percentage of Non-Emitting Controllers" required to assess whether the required reduction has occurred. This approach is consistent with NMED's proposal, which states that records of non-emitting controllers are not required (see 20.2.50.122.C.(1) and 20.2.50.122.D.(1)) and has the added benefit of focusing on reductions in the number of emitting controllers, the real issue, rather than addition of non-emitting controllers. NMOGA's language to achieve this is found in new proposed 20.2.50.122.B.(4)(c). [See below each relevant section.] NMOGA has circulated this proposal to NMED and understands that NMED supports this concept.

Finally, NMOGA believes it is critical to enshrine in the rule language Ms.

Kuehn's statement that the rule does not treat replacement of a natural gas driven controller at an existing facility as a "new" controller, but rather as an existing controller. Kuehn testimony, Tr. 7:2039:12-17. This provision is critical to the orderly phase out of controllers. If a controller failure and replacement triggered the "new" requirements, the owners and operators would be forced into unplanned conversions of entire facilities because it is not cost effective to retrofit a single controller. Bisbey-Kuehn testimony, Tr. 7:2039:12-17; McCabe testimony, Tr. 7:2092:7-11. NMOGA urges the Board to include this change to 20.2.50.122.B.(4)(a) to ensure the workability of the final rule.

For these reasons, the Board should adopt the NMED proposal, with the minor workability changes noted, and reject proposals by other stakeholders to impose more onerous phaseout requirements.

<u>CEP:</u> The Community and Environmental Parties support the Department's proposal to require operators to replace pneumatic controllers that are designed to emit air pollutants with zero-emission alternatives. The CEP propose changes to strengthen the NMED's proposal and make it more effective.

First, and most importantly, The CEP propose to accelerate the transition to zero-emitting controllers to ensure that New Mexico is not needlessly delaying the important environmental benefits. The undisputed evidence shows that pneumatic devices are one of the largest sources of VOC emissions in New Mexico. See CAA Ex. 3 at 7–8. Fortunately, it is possible to replace polluting pneumatic controllers with devices that perform the same function without polluting. Alternatives to polluting controllers include electric controllers and compressed air systems. *Id.* at 8–9. Retrofitting polluting controllers with zero-emission alternatives is a cost-effective method of reducing emissions. *Id.*

In 2020, Colorado's Air Quality Control Commission adopted regulations that require operators to retrofit a substantial portion of their polluting pneumatic controllers by May 2023. CAA Ex. 3 at 11–12. For example, Colorado's rule would require a compressor station operator with a historic percentage of non-emitting controllers of 0 to 20% to retrofit 20% of its polluting controllers by May 2022, an additional 25% of its controllers by May 2023. CAA Ex. 3 at 12–13. Colorado's rule was adopted unanimously, with support from the oil-and-gas industry.

The Department's proposal is similar to Colorado's rule, but provides for a much slower transition to zero-emission devices. To give an example, a Colorado operator of natural gas gathering compressor stations that currently has no non-emitting controllers would have to convert 45% of its controllers at those stations by May 2023. Under the Environment Department's proposal, such an operator would only be required to convert 25% of its controllers by 2024, and would not be required to match the Colorado requirement **until January 2027**. CAA Ex. 23 at 4.

The CEP proposal would accelerate the compliance timeline, while setting two deadlines (May 1, 2023 and May 1, 2025) instead of three deadlines in the Environment Department's proposal (January 1, 2024, January 1, 2027, and January 1, 2030). *See* CAA Ex. 3 at 15. Oxy supports accelerating the transition to zero-emitting devices, and proposes modifications to the rule that would accelerate this transition. *See* Oxy Reb. Ex. 1 at 25-26.

The accelerated phase out would substantially reduce emissions, at reasonable cost. Pneumatic controllers are one of the largest sources of VOC emissions in New Mexico. Clean Air Task Force estimates that there are over 118,000 pneumatic controllers in New Mexico that collectively emit 30,000 metric tons of VOC per year and 108,000 metric tons of methane. CAA Ex. 3 at 7–8. Because these devices emit so much pollution each year, the speed with which the phase out occurs has major implications for public health and the environment. Each additional year of delay means thousands of additional tons of VOCs and tens of thousands of additional tons of methane will be emitted. *Id.* at 21. The impacts of this pollution are irreversible. Accordingly, it is critical that the phase out occur as quickly as possible.

The weight of the evidence indicates that the accelerated phase out proposed by CEP is achievable at reasonable cost. The required pace of retrofits under the program would still be very reasonable and similar to that required in Colorado. This accelerated schedule would therefore not increase overall costs in any significant way; at most, it would require owners and operators to incur some of these costs sooner than they otherwise might (while also increasing cumulative environmental benefits and ensuring that these benefits accrue sooner). CAA Ex. 3 at 25. Notably, no party submitted analysis indicating that the total cost of the retrofit program increases if retrofits occur in earlier years. CAA Ex. 23 at 6.

The Department estimated that the pneumatic retrofit program would cost $2,596 per ton of VOC reduced for gathering and boosting stations, $5,023 per ton of VOC reduced for transmission compressor stations, and $2,745 per ton of VOC reduced for wellhead and tank battery facilities. CAA Ex. 3 at 23. The Department overestimated costs and underestimated benefits, so the program is even more cost-effective than this analysis suggests. CAA Ex. 3 at 23–25. Since there is no evidence that the total cost of the retrofit program increases if retrofits occur in earlier years, it follows that the CEP program can be implemented at reasonable cost as well.

Substantial evidence supports the Community and Environmental Parties' proposal to require sites with electric power to retrofit within six months. The CEP proposed that sites with access to electric power, gas processing plants, and transmission compressor stations should all convert to non-emitting controllers within six months of the effective date of the rule. *See* CAA Ex. 22 at 25 (proposed 20.2.50.122.B(3) NMAC). It has long been recognized that it is simpler, easier, and less expensive to convert sites with electricity to non-emitting controllers. CAA Ex. 23 at 19. The Department's technical analysis shows that all gas processing plants in New Mexico are already using non-emitting controllers, and all of them have access to commercial line electric power. Further, this analysis finds that all transmission compressor stations have access to electric power. CAA Ex. 3 at 16. Kinder Morgan's expert, Leslie R. Nolting, testified that Kinder Morgan has access to commercial power at its transmission compressor stations, and even employs emergency engines to provide **backup** power in the event commercial power is lost due to inclement weather or electric grid equipment failures. CAA Ex. 23 at 24; KM Exhibit VI to Notice of Intent at 19.

There is precedent for requiring a very rapid phase-out of polluting pneumatic devices at larger facilities with access to grid electric power. In December 2017, Colorado required operators of gas processing plants in the Front Range Nonattainment Area to convert to non-emitting pneumatic controllers by May 1, 2018 (i.e., within six months). CAA Ex. 3 at 16–17. Accordingly, the EIB should adopt this aspect of the CEP proposal.

Substantial evidence supports CEP' proposal to require operators to achieve a fixed increase in the percentage of non-emitting controllers, rather than reaching a fixed end point. The CEP propose a change to the structure of the phase-out table, specifically, that operators be required to achieve a fixed increase in the **percentage** of non-emitting controllers, rather than reaching a fixed end point. This makes the rule more effective, more equitable, and less arbitrary, and is consistent with the structure of the rule in Colorado. CAA Ex. 3 at 2, 18. No party put forward evidence opposing this change. Accordingly, EIB should adopt this change.

Substantial evidence does not support the Department's proposal to exempt operators from further retrofits if 75% of their controllers are non-emitting by January 2025. The Department has proposed a provision that states: "if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of table 1 and 2". CAA Ex. 3 at 25 (quoting the proposed 20.2.50.122.B(4)(c)(v) NMAC). The proposed exemption makes the rule less effective because it could result in a large number of pneumatic devices not being converted, even where it would be technically feasible and cost-effective to do so. CAA Ex. 3 at 26. The Department has not set forth any technical or economic basis for this exemption. The Department's analysis shows that it is technically feasible to retrofit emitting controllers with zero-emission controllers and that the cost per ton of VOCs abated is reasonable. The incremental benefits of an additional retrofit are the same regardless of what the operator's historic percentage is.

Substantial evidence does not support NMOGA's proposal to exempt stripper well operators from the pneumatics retrofit program. NMOGA proposes to exempt operators that produce less than 15 barrels of oil equivalent per well per day from the pneumatic retrofit requirement. NMOGA Statement of Intent to Present Technical Testimony, App. A at 47 (proposed section 20.2.50.122.B(3)(c) NMAC). NMOGA's proposed exemption is based on language in the Colorado rule. However, NMOGA's proposal would exempt **twice as many wells** as are exempted by the Colorado rule. CAA Ex. 23 at 21. NMOGA's exemption would apply to much larger firms than the Colorado exemption. For example, Hillcorp Energy Co. would be eligible for the exemption created by NMOGA, and would not have to conduct any retrofits at the **11,400**

wells it owns in New Mexico. The exemption proposed by NMOGA is far too broad. The EIB should reject it.

Substantial evidence supports requiring operators to include polluting pneumatic controllers in their LDAR programs. The CEP proposed requiring operators to include pneumatic devices in their leak detection and repair program. CEP Ex. 1 at 26 (proposing a new subsection at 116.C(4). Since 2018, Colorado has required operators to perform LDAR on polluting pneumatics in the Denver Metro/North Front Range Ozone Nonattainment Area. This requirement was extended to the rest of the state in 2020. CAA Ex. 23 at 3. NMED has incorporated this proposal into its most recent proposal. *See* NMED Jan. 18, 2022 proposal at 28-29. NMOGA and Oxy have also indicated that they support this proposal. *See* Oxy Reb. Ex. 1 at 26-27; 7 Tr. 2110:5–10 [Meyer Test.]. The EIB should adopt this provision. [See also CEP proposed SOR 153-188.]

<u>IPANM proposed extensive changes reflecting its production-based approach in its own Section 122; it is set out in its entirety below the end of NMED's proposal.</u>

<u>The revisions offered to NMED's proposal between this point and IPANM's proposal come from the other parties, primarily NMOGA (its "workability" changes) and CEP (accelerating the compliance timelines). Objections to IPANM's proposal will have already appeared in the sections below and will not be duplicated afterward.</u>

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

<u>NMED:</u> Subsection A of Section 20.2.50.122 applies to natural gas-driven pneumatic controllers and pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and transmission compressor stations. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 122-125. Oxy USA proposed to exempt pneumatic controllers used for artificial lift from the requirements of this Section. NMED did not agree with this proposal, and the Board should reject it. Controllers used for artificial lift can be included in the percentage of controllers that do not need to be non-emitting, and can be addressed through the

flexibilities provided in this Section that allow owners and operators to prioritize which controllers are retrofitted or replaced first. NMED Rebuttal Exhibit 1, p. 87-88.

IPANM earlier proposed to exempt well sites or tank batteries with three or fewer controllers. This proposal would, in effect, exempt nearly all, if not all, controllers located at well sites and tank batteries. Based on the GHGRP data used to develop the cost estimates for the pneumatic controller requirements, well sites and tank batteries in the San Juan Basin have an average of five pneumatic controllers per well and those in the Permian Basin have an average of only one pneumatic controller per well. The industry commenters did not provide data or testimony on the impact this exemption would have on the number of controllers impacted or how the exclusion would affect costs or emission reductions. *Id.* at 88.

<u>Oxy proposes an addition to the end of paragraph 122A:</u>

"**Artificial lift controllers located at wellhead only facilities are exempt from these requirements."**

<u>Oxy:</u> Artificial lifts located at wellhead-only facilities should be exempt from the requirement to retrofit with access to commercial line electrical power. Wellhead-only facilities are often in remote areas. As Mr. Holderman testified during the hearing, "… it's not always logistically feasible to electrify these locations due to issues outside of Oxy USA's control, including right of way issues, distance from line power, and the capacity [for electricity] at a facility. Even without the foregoing concerns, the cost and timing can be prohibitive. The cost to run an electrical line in Southwest New Mexico at a facility is around $200,000 per mile, and with lead times up to a year at present." Hearing Transcript at TR-2212:9-23. In addition, wellhead-only facilities do not contain other production or processing equipment. Exempting artificial lifts at these facilities would allow operators to focus resources to retrofit producing locations and would result in the greatest emissions reductions.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

<u>NMED:</u> Paragraph (1) of Subsection B of Section 20.2.50.122 requires all new natural gas-driven pumps are required to comply with the emission standards of Section 20.2.50.122 upon startup. Paragraph (2) of Subsection B of Section 20.2.50.122 requires existing natural gas-driven pneumatic pumps to comply with the emission standards in Section 20.2.50.122 within three years of the effective date of Part 50. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 125-131.

(3) An existing natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 – WELL SITES, STANDALONE TANK BATTERIES, GATHERING AND BOOSTING STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 2 – TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	95%	98%
> 60-75%	80%	95%	98%
> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

NMED: Paragraph (3) of Subsection B of Section 20.2.50.122 sets forth the required schedules and targets for replacing existing natural gas-driven pneumatic controllers with non-emitting controllers. Table 1 contains the schedule and targets for well Sites, tank batteries, and gathering and Boosting Stations. Table 2 contains the schedule and targets for natural gas compressor stations and gas processing plants. The target is based on the number of pneumatic controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of Part 50. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except pneumatic controllers that are necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.

The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, p. 125-131; NMED Rebuttal Exhibit 1, pp. 82-90. The Department's proposal allows owners and operators to prioritize their highest producing sites and sites with utility electric power for retrofitting first. In this regard, there is no material difference between the Department's proposal and those based on the Colorado approach, except that while Colorado mandates that high production sites must be prioritized, NMED's proposal does not, and therefore provides more flexibility to owners and operators to select the most cost-effective sites to be retrofitted first. NMED Rebuttal Exhibit 1, pp. 85-86.

NMOGA proposes a change to Section 122B(3):

(3) An owner or operator shall ensure that its existing natural gas-driven pneumatic controllers shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule

NMOGA: The change is made to reflect testimony by Ms. Kuehn and evident intent of provision to require each owner/operator to reduce the number of pneumatic controllers in its operations by the specified percentage. It is obvious from the testimony of all witnesses that an individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. It is obvious from the testimony of all witnesses that the reduction percentages are aimed at the group of existing controllers as an individual controller cannot partially reduce emissions but must be retrofitted to a non-emitting controller or replaced or eliminated. Bisbey-Kuehn testimony, Tr. 7:2027:9-13 ("the proposed provisions of this section will likely achieve higher emission reductions from pneumatic controllers by targeting reductions in the overall number of emitting controllers…"); 7:2029:6-7:2030:9 (referencing changes to the "fleet" of controllers).

<u>CEP proposes new language for B(3) and a new B(4):</u>

(3) An existing natural gas-driven pneumatic controller <u>at a site with access to commercial line electrical power, and any existing natural-gas driven pneumatic controller at a transmission compressor station or a natural gas processing plant, shall comply with this Section within six months of the effective date of this Part.</u>

<u>(4) At sites that do not have access to commercial line electrical power, owners and operators shall retrofit their fleet of existing natural gas-driven pneumatic controllers according to the following schedule:</u> ~~shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:~~

<u>CEP:</u> It has long been recognized that it is simpler, easier, and less expensive to convert sites with electricity to non-emitting controllers. CAA Ex. 23 at 19. There is precedent for requiring a very rapid phase-out of polluting pneumatic devices at larger facilities with access to grid electric power. In December 2017, Colorado required operators of gas processing plants in the Front Range Nonattainment Area to convert to non-emitting pneumatic controllers by May 1, 2018 (i.e., within six months). CAA Ex. 3 at 16–17. The EIB should follow this precedent and require a similarly rapid phase out at sites in New Mexico with access to commercial line electric power. <u>See also CEP proposed SOR 170-175.</u>

<u>Oxy and CEP propose to replace NMED's Table 1 in 122B(3) with their own, to accelerate the phaseout of polluting pneumatic controllers:</u>

Table 1 – COMPLIANCE SCHEDULE BY HISTORIC LIQUIDS PRODUCTION

Total Historic Percentage of Liquids Produced at Facilities with Non-Emitting	Conversion Required by December 31, 2023	Maximum Required Percentage by December 31, 2023	Additional Conversion Required by May 1, 2025	Maximum Required Percentage by May 1, 2025	Additional Conversion Required by May 1, 2027	Maximum Required Percentage by May 1, 2027
> 75 %	+10%	92%	+8%	94%	+3%	96%
> 60-75 %	+15%	85%	+10%	93%	+7%	95%
> 40-60 %	+20%	75%	+18%	85%	+12%	92%
> 20-40 %	+30%	60%	+25%	78%	+15%	90%
0-20 %	+35%	50%	+25%	75%	+25%	90%

Oxy: The final version of the proposed rule maintains the compliance schedule that the Department initially proposed in the May 6, 2021 version of the proposed rule – a compliance schedule that requires a certain percentage of pneumatic controllers and pumps to be in compliance by a specific date. By not tying these completion goals to production, NMED's proposal puts "form over substance." As Oxy USA has consistently noted throughout this process, basing the compliance timeline for pneumatic controllers on historic liquids production as opposed to the number of pneumatic controllers at a site – i.e., requiring that the pneumatic controllers with highest historic liquids production be addressed first – would better ensure that the pneumatic controllers that are actuated most frequently, and therefore have the potential to emit more often, are retrofitted first. A percentage-driven compliance schedule does not compel operators to target the higher producing (i.e., higher emitting) sites first. In fact, a percentage-driven compliance schedule could incentivize addressing the lower producing sites sooner than the higher producing sites, even though emissions reductions will be greater at the latter. NMED has already acknowledged the value of tying obligations to production. During a discussion of the 20.2.50.116 NMAC leak detection requirements at the hearing, Ms. Bisbey-Kuehn noted that the frequency of AVO obligations was based on the understanding that, " … higher production facilities will have necessarily higher – more equipment with more leakage opportunities and should be inspected more frequently." Hearing Transcript at TR-2451:20-25 and TR-2452:1-3. This explanation follows common sense – higher producing facilities should be surveyed more often because they likely emit more often. The same logic applies to pneumatic controllers – facilities with greater historic liquids production will have more opportunities for pneumatic controller emissions. Oxy USA encourages the Board to adopt the modified implementation schedule previously proposed in Oxy USA Rebuttal Exhibit 1, which was also supported by the e-NGOs.

CEP: Table 1 is modified to require a more rapid phase out, with a slightly different structure. The CEP propose to accelerate the transition to zero-emitting controllers to ensure that New Mexico is not needlessly delaying the important environmental benefits. In 2020, Colorado's Air Quality Control Commission adopted regulations that require operators to retrofit a substantial portion of their polluting pneumatic controllers by May 2023. CAA Ex. 3 at 11–12. For example, Colorado's rule would require a compressor station operator with a historic percentage of non-emitting controllers of 0 to 20% to retrofit 20% of its polluting controllers by May 2022, an additional 25% of its controllers by May 2023. CAA Ex. 3 at 12–13. Colorado's rule was adopted unanimously, with support from the oil-and-gas industry. Id.

NMED's proposal is similar to Colorado's rule, but provides for a much slower transition to zero-emission devices. For example, a Colorado operator of natural gas gathering compressor stations that currently has no non-emitting controllers would have to convert 45% of its controllers at those stations by May 2023. Under NMED's proposal, such an operator would only be required to convert 25% of its controllers by 2024, and would not be required to match the Colorado requirement until January 2027. CAA Ex. 23 at 4.

The CEP proposal would accelerate the compliance timeline, while setting two deadlines (May 1, 2023 and May 1, 2025) instead of three deadlines in NMED's proposal (January 1, 2024, January 1, 2027, and January 1, 2030). See CAA Ex. 3 at 15. The proposal still provides more time from the start of the rule than the Colorado rule. The weight of the evidence shows that accelerating the transition to zero-emission pneumatics will have tremendous public health benefits. Pneumatic controllers are one of the largest sources of VOC and methane emissions in New Mexico. Clean Air Task Force estimates that there are over 118,000 pneumatic controllers in New Mexico that collectively emit 30,000 metric tons of VOC per year and 108,000 metric tons of methane. CAA Ex. 3 at 7–8. Because these devices emit so much pollution each year, the speed with which the phase out occurs has major implications for public health and the environment. Each additional year of delay means thousands of additional tons of VOCs and tens of thousands of additional tons of methane will be emitted. Id. at 21. The impacts of this pollution are irreversible.

The weight of the evidence indicates that the accelerated phase out proposed by the CEP is achievable at reasonable cost. The required pace of retrofits under the program would still be very reasonable and similar to that required in Colorado. This accelerated schedule would therefore not increase overall costs in any significant way; at most, it would require owners and operators to incur some of these costs sooner than they otherwise might (while also increasing cumulative environmental benefits and ensuring that these benefits accrue sooner). CAA Ex. 3 at 25. Notably, no party submitted analysis indicating that the total cost of the retrofit program increases if retrofits occur in earlier years. CAA Ex. 23 at 6.

The CEP propose a change to the structure of the phase-out table. Specifically, they propose that operators be required to achieve a fixed increase in the percentage of non-emitting controllers, rather than reaching a fixed end point. This makes the rule more effective, more equitable, and less arbitrary, and is consistent with the structure of the rule in Colorado. CAA Ex. 3 at 2, 18. No party put forward evidence opposing this change. Accordingly, EIB should adopt this change. Table 2 is not needed, because all Transmission Compressor Stations and Gas Processing Plants have access to commercial line electric power and can convert within six months. See CAA Ex. 3 at 16. See also CEP proposed SOR 153-191.

Pneumatic controllers are a significant source of pollution in New Mexico. Pneumatic controllers that are operated with natural gas emit air pollutants, both as part of their normal operation and when they malfunction. Natural gas is primarily composed of methane, a potent greenhouse gas. Other pollutants, including ozone-forming VOCs and toxic or cancer-causing hazardous air pollutants, are typically present in natural gas at sites such as well production facilities, gathering compressor stations, and processing plants. Pneumatic controllers are designed to release the gas that is used to operate them, and typically are configured to release that gas directly into the atmosphere. When natural gas is used to operate controllers, that gas (and the air pollutants it contains) is emitted into the atmosphere. CAA Ex. 3 at 4.

Pneumatic controllers often malfunction, which causes them to emit more natural gas than they are designed to emit. For example, intermittent-bleed controllers, which are the most common type in New Mexico, are designed to emit only during the actuation cycle for the controller, but in the field, these devices frequently emit between actuations. CAA Ex. 3 at 5.

Given the extent to which pneumatic devices malfunction and emit more than they are designed to emit, it is difficult to precisely quantify emissions from these devices. However, Clean Air Task Force analysis of data collected for the Permian and San Juan basins in EPA's Greenhouse Gas Reporting program indicates that there are over 118,000 pneumatic controllers in New Mexico that collectively emit about 108,000 metric tons of methane and about 30,000 metric tons of VOC. Analysis from EDF indicates that pneumatic devices are the second largest source of methane emissions from the oil and gas industry in New Mexico. CAA Ex. 3 at 7–8.

Replacing polluting pneumatic controllers with zero-emission controllers is a proven, cost-effective strategy for reducing emissions. It is possible to replace polluting pneumatic controllers with devices that perform the same function without polluting. Several cost-effective technologies are available that can entirely eliminate emissions from gas-driven pneumatic controllers, at new and existing sites, with and without electricity available. The first approach is to use compressed air instead of pressurized natural gas to operate controllers. A second approach is to use electric controllers, avoiding the use of pneumatic operation. CAA Ex. 3 at 8–9.

Retrofitting polluting controllers with zero emission alternatives is a cost-effective method for reducing emissions. Clean Air Task Force conducted analysis as part of a recent rulemaking in Colorado that demonstrated that converting to these technologies at new and existing well-pads and compressor stations was a cost-effective mitigation approach for reducing VOC and methane emissions. This conclusion is well supported by a number of recent regulations that prohibit installation of new gas-driven pneumatic controllers (unless emissions are captured or controlled). CAA Ex. 3 at 10.

Colorado has adopted an aggressive plan to phase out polluting pneumatic controllers, with industry support. In 2020, Colorado's Air Quality Control Commission adopted regulations that require operators to retrofit a substantial portion of their polluting pneumatic controllers to use non-emitting controllers over the next few years. CAA Ex. 3 at 11–12. For compressor stations, operators in Colorado are required to retrofit a certain percentage of their polluting pneumatic devices by May 2022. Each operator must convert additional polluting controllers by May 2023. The number of devices an operator must convert depends on the total historic percentage of non-emitting controllers in the operator's fleet. Generally, an operator starting with a smaller percentage of non-emitting controllers must convert a greater number of controllers;

however, all operators that utilize polluting pneumatic controllers must retrofit some additional controllers. CAA Ex. 3 at 12–13. For example, a compressor station operator with a historic percentage of non-emitting controllers of 0 to 20% would be required to retrofit 20% of its polluting controllers by May 2022. It would then be required to retrofit an additional 25% of its controllers by May 2023. Thus, an operator that started without any zero-emission controllers would be required to convert 55% of its controllers to non-emitting within two years. CAA Ex. 3 at 12–13.

For oil and gas production facilities, the Colorado rule establishes a retrofit schedule with the same timelines and a similar structure as the table applicable to compressor stations. However, instead of retrofitting a given percentage of their **controllers**, operators must convert a certain percentage of their **production** to non-emitting. Specifically, operators must convert facilities that account for a certain percentage of the operator's total liquids production (liquid hydrocarbons plus produced water) in the state by each date. For example, an operator that currently produces 10% of its statewide liquids at well pads with no emitting pneumatics must convert well pads that account for 15% of the operator's total statewide liquids to non-emitting by May 2022, and then must convert additional well pads that account for 25% of the operator's total statewide liquids to non-emitting by May 2023. CAA Ex. 3 at 13.

The CEP proposal would accelerate the compliance timeline, while setting two deadlines (May 1, 2023 and May 1, 2025) instead of three deadlines in the Environment Department's proposal (January 1, 2024, January 1, 2027, and January 1, 2030). *See* CAA Ex. 3 at 15. Each additional year of delay means thousands of additional tons of VOCs and tens of thousands of additional tons of methane will be emitted. Those environmental and public health impacts are irreversible. CAA Ex. 3 at 21.

There is precedent for conducting a rapid phase out of polluting pneumatics at transmission compressor stations and other facilities with access to grid power. Community and Environmental Parties proposed that sites with access to electric power, gas processing plants, and transmission compressor stations should all convert to non-emitting controllers within six months of the effective date of the rule. *See* CAA Ex. 22 at 25 (proposed 20.2.50.122.B(3) NMAC.

It has long been recognized that it is simpler, easier, and less expensive to convert sites with electricity to non-emitting controllers. CAA Ex. 23 at 19. The Department's technical analysis shows that all gas processing plants in New Mexico are already using non-emitting controllers, and all of them have access to commercial line electric power. Further, this analysis finds that all transmission compressor stations have access to electric power. CAA Ex. 3 at 16.

Kinder Morgan's expert, Leslie R. Nolting, testified that Kinder Morgan has access to commercial power at its transmission compressor stations, and even employs emergency engines to provide **backup** power in the event commercial power is lost due to inclement weather or electric grid equipment failures. CAA Ex. 23 at 24; KM Exhibit VI to Notice of Intent at 19. There is precedent for requiring a very rapid phase-out of polluting pneumatic devices at larger facilities with access to grid electric power. In December 2017, Colorado required operators of gas processing plants in the Front Range Nonattainment Area to convert to non-emitting pneumatic controllers by May 1, 2018 (i.e., within six months). CAA Ex. 3 at 16–17.

While pipeline-quality gas has a lower VOC content than gas further upstream, transmission compressor stations can still be a significant source of VOCs, and converting to zero-emitting pneumatic devices is a particularly cost effective way to reduce emissions from these sources. CAA Ex. 23 at 24. Rather than Requiring Operators to Achieve a Fixed *Percentage* of Non-Emitting Controllers, the Rule Should Require Operators to Achieve a Fixed *Increase.* Requiring operators to achieve a fixed **percentage**, no matter where they lie within their cohort, is less efficient, less equitable for operators, and creates arbitrary outcomes. It may also create an incentive for operators to undercount the number of existing pneumatic devices, or perversely, to delay retrofits so they remain in a favorable position (i.e., immediately below a threshold for inclusion in the next higher cohort). CAA Ex 3 at 17–19. Colorado requires operators to achieve a fixed **increase** in the percentage of non-emitting controllers. CAA Ex. 3 at 18.

The Department's Proposed Retrofit program is cost effective. The Department estimated that the pneumatic retrofit program would cost $2,596 per ton of VOC reduced for gathering and boosting stations, $5,023 per ton of VOC reduced for transmission compressor stations, and $2,745 per ton of VOC reduced for wellhead and tank battery facilities. CAA Ex. 3 at 23.

The Department's estimates generally are reasonable, but they have overestimated the net costs of pneumatic controller retrofits for several reasons. First, the Department's estimates omit the increased revenues that operators receive because, after retrofitting facilities to eliminate venting pneumatic controllers, they are able to sell the gas that the pneumatic controllers would otherwise vent. Second, the Department's estimates omit the maintenance savings that operators realize when they convert from gas-driven controllers to instrument air or electric controllers. Third, the Department estimates the costs for retrofitting all sites with access to electricity by modeling costs for instrument air systems. For smaller sites, electric controllers will often be more cost effective. Fourth, the Environment Department fails to account for the fact that operators will likely replace all of the devices at a particular site at the same time. CAA Ex. 3 at 23–25. Valor EPC (Valor), a consultant for NMOGA, estimated that the annualized cost of the pneumatic retrofit program would be $7,213 per ton of VOC reduced. CAA Ex. 23 at 13. Valor radically overestimated the costs of the Environment Department's proposed regulation of pneumatic controllers, and ignores the ways the Department overestimated costs. Valor makes a variety of variety of erroneous assumptions that lead it to overestimate equipment and installation costs. CAA Ex. 23 at 14.

Valor's analysis used an emission factor for intermittent-bleed controllers that is much lower than the factor recommended by EPA. While Colorado used an emission factor for intermittent-bleed controllers of 3.5 standard cubic feet per hour ("scf/hr") for its 2020 pneumatics rule, this is too low for New Mexico. It is most appropriate for New Mexico to continue using the EPA emission factor of 13.5 scf/hr. CAA Ex. 23 at 7–13. Valor's cost estimate is also based on air compression equipment that is sized to provide a much greater volume of compressed air to the pneumatic controllers at a site than those pneumatic controllers would need, based on Valor's claims about emissions from the controllers. CAA Ex. 23 at 14–15.

A more rapid phase out, as CEP propose, would also be cost effective. The CEP propose to accelerate the transition already required by the Department's proposal. The required pace of retrofits under the program would still be very reasonable and similar to that required in Colorado. This accelerated schedule would therefore not increase overall costs in any significant way; at most, it would require owners and operators to incur some of these costs sooner than they otherwise might (while also increasing cumulative environmental benefits and ensuring that these benefits accrue sooner). CAA Ex. 3 at 25. No party submitted analysis indicating that the total cost of the retrofit program increases if retrofits occur in earlier years. While costs may be incurred earlier, the benefits to public health and the environment (as well as benefits to industry in the form of increased revenue and maintenance savings) will be realized earlier as well. CAA Ex. 23 at 6.

There is no need to exempt operators that convert 75% of their polluting controllers from further requirements. The Department has proposed a provision that states: “if an owner or operator meets at least 75% total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of table 1 and 2.” CAA Ex. 3 at 25 (quoting the proposed 20.2.50.122.B(4)(c)(v) NMAC). The proposed exemption makes the rule less effective because it could result in a large number of pneumatic devices not being converted, even where it would be technically feasible and cost effective to do so. CAA Ex. 3 at 26. The Department has not set forth any technical or economic basis for this exemption. The Department’s analysis shows that is technically feasible to retrofit emitting controllers with zero-emission controllers and that the cost per ton of VOCs abated is reasonable. The incremental benefits of an additional retrofit are the same regardless the operator’s historic percentage. CAA Ex. 3 at 26.

NMOGA’s proposed exemption for stripper well operators would exempt operators that can easily afford to replace outdated, polluting controllers. NMOGA proposes to exempt operators that produce less than 15 barrels of oil equivalent per well per day from the pneumatic retrofit requirement. NMOGA Statement of Intent to Present Technical Testimony, App. A at 47 (proposed section 20.2.50.122.B(3)(c) NMAC). NMOGA’s proposed exemption is based on language in the Colorado rule. However, NMOGA’s proposal would exempt **twice as many wells** as are exempted by the Colorado rule. CAA Ex. 23 at 21. NMOGA’s exemption would apply to much larger firms than the Colorado exemption. For example, Hillcorp Energy Co. would be eligible for the exemption created by NMOGA, and would not have to conduct any retrofits at the **11,400 wells** it owns in New Mexico. The exemption proposed by NMOGA is far too broad. CAA Ex. 23 at 22.

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

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator is not subject to the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional or inhouse engineer.

(d) Temporary pneumatic controllers that emit natural gas and are used for well abandonment activities or used prior to or through the end of flowback, and pneumatic controllers used as emergency shutdown devices located at a well site, are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(e) Temporary or portable pneumatic controllers that emit natural gas and are on-site for less than 90 days are not subject to the requirements of

Subsection B of 20.2.50.122 NMAC.

<u>NMED:</u> Paragraph (4) of Subsection B of Section 20.2.50.122 sets forth the emissions standards for natural gas-driven pneumatic controllers. Subparagraph (a) provides that new pneumatic controllers are required to have an emission rate of zero. Subparagraph (b) outlines the process by which owners and operators of existing pneumatic controllers determine what percentage of non-emitting controllers they have to meet, which provisions of Tables 1 and 2 apply, and the replacement schedule they must meet. Subparagraph (c) authorizes pneumatic controllers with a bleed rate exceeding six standard cubic feet per hour if the owner or operator demonstrates that a higher bleed rate is required based on functional needs. Subparagraph (d) exempts temporary pneumatic controllers used for well abandonment activities or prior to flowback and pneumatic controllers used as emergency shut down devices at a well site from the requirements of Subsection B. Subparagraph (e) exempts temporary or portable pneumatic controllers that are onsite for less than 90 days from the requirements of Subsection B. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 122-137; NMED Rebuttal Exhibit 1, pp. 83-90; Tr. Vol. 7, 2025:10 – 2033:20.

[GCA's earlier proposals in this Section are not part of its final proposal.].

The eNGO parties withdrew their initial proposal in their rebuttal testimony in favor of the joint proposal with Oxy USA, which the Board will address above. The eNGO's initial proposal may have led to faster reductions in emissions, but failed to account for the number of controllers affected, the number of facilities required to comply with this Section, and the time needed to come into compliance, making the proposed timelines impractical and unreasonable. NMED Rebuttal Exhibit 1, pp. 89-90. The Department testified that it will review such requests on a case-by-case basis and will make a determination whether or not the request should be granted, thus ensuring that only reasonable and fully supported waiver requests are allowed. *See id.* at 90.

<u>Kinder Morgan:</u> The Department confirmed its intent that operators of transmission compressor stations and gas processing plants comply with the requirements of Table 2, and the Board should adopt this section as proposed. [See Kinder Morgan's Closing Argument at pp. 12-15 for a more detailed history of the evolution of this section.]

The Department reasonably decided to strike 20.2.50.122.B.(4)(b) NMAC reflected in the September 16 Version of 20.2.50 NMAC. That prior language would have required existing pneumatic controllers with access to commercial line electric power to install/retrofit to zero bleed pneumatic controllers within 2 years of the effective date of this subpart. During hearing, the Department recognized that that provision, unsupported by technical feasibility and cost data, would come in direct conflict with Table 2, and would result in problematic outcomes. For example, while transmission compressor stations are typically tied into commercial line electric power, that does not mean that the station has adequate power to install additional equipment or sufficient infrastructure in place to route power to that a particular piece of additional equipment. The Department confirmed its intent that operators of transmission compressor stations and gas processing plants comply with the requirements of Table 2, and we ask the Board to adopt this section as proposed. The Board should set aggressive, yet achievable, targets for operators to retrofit or replace existing pneumatic controllers with non-emitting controllers; and the schedules set forth in Tables 1 and 2 achieve this outcome.

<u>NMOGA proposed extensive changes throughout paragraph (4):</u>

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

(a) new pneumatic controllers shall have an emission rate of zero. <u>A natural gas driven pneumatic controller replacing an existing natural gas driven pneumatic controller at an existing facility is an existing pneumatic controller for purposes of Section 20.2.50.122.</u>

(b) <u>owners and operators of</u> existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by ~~January~~ July 1, 2023, the owner or operator shall determine the total controller count for all controllers <u>subject to each table separately</u> at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count <u>for each table</u> must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count. <u>This final number is the total historic controller count. Controllers identified as required for a safety or process purpose after July 1, 2023 shall not affect the total historic controller count.</u>

(ii) determine which controllers in the total controller count <u>for each table</u> are non-emitting and sum the total number of non-emitting controllers

and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers for each table by dividing the total historic non-emitting controller count by the total historic controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above for each table, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers using the calculation methodology in paragraph (4)(c) by January 1, 2025, for either or both table 1 or table 2, the owner or operator is not thereafter subject to the requirements of ~~tables 1 and 2~~ that table(s) of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) owners and operators of existing natural gas driven pneumatic controllers shall demonstrate compliance with tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, on January 1, 2024, January 1, 2027, and January 1, 2030, as follows:

(i) determine which controllers are emitting (excluding pneumatic controllers necessary for safety or process reasons pursuant to Paragraph (4)(d) of Subsection B of 20.2.50.122 NMAC) and sum the total number of emitting controllers for table 1 and table 2 facilities separately.

(ii) determine the percentage of non-emitting controllers by using the following equation for table 1 and table 2 facilities separately:

Total percentage of non-emitting controllers = 100 – ((total emitting controllers / total historic controller count) x 100)

(iii) compliance is demonstrated if the Total Percentage of Non-Emitting Controllers calculated pursuant to Paragraph (4)(c)(ii) is less than or equal to the value for that year in the Total Historic Percentage of Non-Emitting Controllers row (calculated in Paragraph (4)((b)(iv)) of table 1 or table 2, as applicable, of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

(d) No later than January 1, 2024 , a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted only when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller as excepted for process or safety reasons under clause (i) of subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be

certified by a qualified professional or inhouse engineer.
……….

NMOGA: Ms. Kuehn clearly stated that "like kind replacement" of existing controllers at existing facilities should not trigger the "new" controller provision, to avoid inadvertent or unplanned conversion of facilities. Tr. 7:2039:12-17; NMOGA Exhibit 47, 46:38-40, 48:35 – 49:2. As to (4)(b)(i), Ms. Kuehn stated a general intent to achieve a January 1, 2023 date. Tr. 7:2042:8-11. However, the progress of the rulemaking has been slower, Ms. Kuehn agreed that more devices may be needed for safety or process purposes, Kuhn/Palmer testimony, Tr. 7:2040:2-2041:5. Mr. Smitherman testified that this couldn't be done in 6 months, Smitherman testimony, Tr. 7:2108:11-27, Ms. Nolting testified that completing the inventory was extremely time consuming already, Tr. 7:2284:19-21, and Ms. Kuehn testified that the documentation was needed only for those that would otherwise be phased out, which suggests a rolling evaluation (for other than high-bleed devices), which reduces the immediate burden. Tr. 7:2041:10-20. Given this testimony and the fact that the first deadline for reductions is January 1, 2024, NMOGA believes that Ms. Kuehn may not have appreciated the infeasibility of the January 1, 2023 date in light of the changes discussed and the role of pneumatic controllers needed for safety or process reasons. NMOGA believes a July 1, 2023 date provides more time for the resource intensive inventory. This would also be the date used to "set" the phase out schedule in tables 1 and 2. This then gives owners/operators 66 more months to ensure that they can meet the first phase out deadline on January 1, 2024.

As to the insertions around tables, Ms. Kuehn's testimony is based upon reductions occurring at each "group" of table 1 or table 2 facilities. However, the calculation methodology does not distinguish between the table 1 and table 2 facilities. Separate calculation for each table is needed to create an "apples to apples" comparison to track progress between "historic" and January 1, 2024, January 1, 2027 and January 1, 2030 performance. Otherwise, an operator's failure to make progress at its table 1 sites may result in its table 2 sites being in violation and vice versa. This is surely not the intended result. The final sentence in (4)(b)(i) is added to reflect reality that not all devices required for safety or process reasons will be known by either January 1, 2023 or July 1, 2023. Kuehn/Palmer testimony, Tr. 7:2042:5-7 (conceding that "ideally" the devices could be identified by January 1, 2023). As Mr. Smitherman testified, some of these devices are necessary to provide a safe working environment and the rule needs to allow this. Smitherman testimony, NMOGA Exhibit A1:30:4-16. The change allows for future additions but provides that they do not affect the total historic controller count used to establish obligations under tables 1 and 2. NMOGA believes that this is consistent with the Department's intent and provides a route to maintain controllers required for safety or process reasons if missed during the initial pass.

The first changes in (4)(b)(v) are added to establish how to count non-emitting controllers for compliance purposes after the initial count. See the rationale for Paragraph (4)(c) below for details. The second change is made to reflect Ms. Kuehn's testimony that sources that meet the 75% prior to January 1, 2025 date must still meet the January 1, 2024 reduction percentage. Kuehn/Palmer testimony, Tr. 7:2043:16-7:2045:21.

Regarding NMOGA's proposed new paragraph (4)(c), the rule as drafted does not establish a compliance methodology to demonstrate compliance with the January 1, 2024, 2027 and 2030 compliance dates. NMOGA proposes new paragraph (4)(c) to meet this need. While tables 1 and 2 talk about percent of "non-emitting controllers," for purposes of phasing out, what is important is reducing the number of emitting controllers. In addition, Paragraph (1) of both Subsections C and D do not require records of non-emitting controllers, so there is no non-emitting controller data to use. Therefore, NMOGA uses the "emitting controller count," excluding pneumatic controllers "permitted" because necessary for safety or process reasons. Kuehn/Palmer testimony, Tr. 7:2041:1-5. NMOGA then proposes use of the equation: 100 – ((existing controller count (in 2024, 2027 or 2030) / total historic controller count) x 100, which gives a final value directly comparable to tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC. In essence, if 100% is the total number of emitting and non-emitting controllers, and we subtract the percentage of emitting controllers, what is left is the percentage of non-emitting controllers.

Regarding the January 2024 date in newly re-lettered paragraph (4)(d), upon reviewing the final language, NMOGA realized that this provision "phases out" high-bleed devices unless the required demonstration is made. This cannot be accomplished by the effective date. NMOGA had proposed to phase out all non-safety/process high-bleed controllers within two years. NMOGA thus proposes to align the phase out with the January 1, 2024 first compliance date, allowing just less than two-years to inventory and prepare the justification for high bleeds, resulting in an effective phase out. NMOGA Ex. 47, 48:33-34 (“High Bleed Controller shall be retrofitted or replaced no later than January 1, 2024 unless” demonstrated as necessary for safety or process reasons). NMOGA appreciates the inclusion of the provision (NMED’s paragraph (4)(c)), as certain pneumatic controllers are required for process and safety reasons. NMOGA believes, however, that the language as currently written might “freeze” in place high-bleed devices (to qualify for the exception) when low-bleed or intermittent devices might be used. Ms. Kuehn indicated that this was not NMED’s intent. The language changes reflect that discussion and allow lower emitting devices to be substituted for higher emitting ones. This advances the goal of reducing release of natural gas.

The CEP propose extensive changes throughout Section B through D:

(4/5) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers at sites with access to commercial line electrical power, and any existing pneumatic controller at a transmission compressor station or a natural gas processing plant, shall have an emission rate of zero.

(~~b~~c) At sites without access to commercial line electric power, existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator’s affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers ~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ that are permitted under Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 ~~and 2~~ of Paragraph (4~~3~~) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

~~(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator is not subject to the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.~~

~~(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.~~

(~~c~~d) a pneumatic controller with a bleed rate greater than ~~six standard cubic feet per hour~~ zero is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purpose prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional or inhouse engineer. …………

C. Monitoring requirements:

(2) The owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility……………

D. Recordkeeping requirements:

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 ~~and 2~~ of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller………

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than ~~six standard cubic feet per hour~~ zero shall maintain a record documenting why a bleed rate greater than ~~six scf/hr~~ zero is necessary, as required in Subsection B of 20.2.50.122 NMAC……..

(9) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Subsection F of 20.2.50.116 NMAC.

CEP: The proposed exemption makes the rule less effective because it could result in a large number of pneumatic devices not being converted, even where it would be technically feasible and cost-effective to do so. CAA Ex. 3 at 26. NMED has not set forth any technical or economic basis for this exemption. NMED's analysis shows that it is technically feasible to retrofit emitting controllers with zero-emission controllers and that the cost per ton of VOCs abated is reasonable. The incremental benefits of an additional retrofit are the same regardless of the operator's historic percentage.

(5) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at natural gas processing plants shall have an emission rate of zero.

(b) new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero within two years of the effective date of this Part.

(d) owners and operators of pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic diaphragm pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic diaphragm pump emissions to the control device within two years of the effective date of this Part.

<u>NMED:</u> Paragraph (5) of Subsection B of Section 20.2.50.122 sets forth the emissions standards for natural gas-driven pneumatic diaphragm pumps. Natural gas-driven pumps located at natural gas processing plants must have an emission rate of zero. Natural gas-driven pumps located at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations with access to commercial power must have an emission rate of zero. Owners and operators of pneumatic pumps at well sites, tank batteries, gathering and boosting stations, or natural gas compressor stations without access to commercial line electrical power are required to reduce VOC emissions from this equipment by 95 percent if it is technically feasible to route those emissions to a control device, fuel cell, or process. If an existing on-site control device is not capable of achieving a 95 percent reduction of VOC emissions, and it is not technically feasible to route pneumatic pump emissions to a fuel cell or process, the owner or operator must route the emissions to the existing control device. The Board should adopt this proposal

for the reasons stated in NMED Exhibit 32, pp. 126, 130-38; NMED Rebuttal Exhibit 1, pp. 83-90; Tr. Vol. 7, 2033:21 – 2034:22.

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force are not subject to the monitoring requirements in Subsection C of 20.2.50.122 NMAC.

(2) The owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller shall, on a monthly basis, conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The owner or operator's database shall contain the following:

(a) natural gas-driven pneumatic controller unique 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) if continuous, design annual bleed rate in standard cubic feet per year.

(5) The owner or operator of a natural gas-driven pneumatic diaphragm pump shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(6) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.122 contains monitoring requirements for pneumatic controllers and pumps. Pneumatic devices that do not use natural gas or other hydrocarbon gas as motive force are exempt from the monitoring requirements. Owners and operators of facilities with pneumatic controllers that are subject to the deadlines in this Section must monitor the compliance status of each controller at each facility; conduct a monthly AVO or OGI inspection; inspect the controller and perform necessary maintenance to maintain the unit in accordance with manufacturer specifications and ensure VOC emissions are minimized; and must maintain the specified information on each controller in a database. Owners and operators of facilities with pneumatic pumps must conduct a monthly AVO or OGI inspection; inspect the pump and perform necessary maintenance to maintain the unit in accordance with manufacturer specifications and ensure VOC emissions are minimized. Pneumatic controllers must comply with the LDAR requirements in Paragraph (3) of Subsection C of Section 20.2.50.116, and owners and operators must verify that intermittent controllers are not emitting when not actuating. If an intermittent controller is found to be emitting when not actuating, it must be repaired in accordance with Subsection E of 20.2.50.116 NMAC. Monitoring events must be date and time stamped. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112.

The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 127, 130-38; Tr. Vol. 7, 2034:23 – 2036:18.

Oxy proposes a new sentence at the end of C(6):

"**Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the department unless the owner or operator fails to determine whether the pneumatic controller is operating properly, fails to perform any necessary response, fails to keep required records, or fails to submit reports in accordance with the rule.**"

Oxy: Oxy USA supports the Department's addition to Section 122.C that applies the monitoring requirements of 20.2.50.116 NMAC to pneumatic controllers, but believes it is necessary to add language to clarify that detectable emissions should not trigger enforcement if the owner or operator properly addresses any findings. Mr. Holderman stated "Oxy USA believes this clarification is necessary because optical gas imaging and Method 21 inspections cannot quantify [an] emission rate." Hearing Transcript at TR-2213:8-11. In addition, providing a clear process to rectify issues without enforcement incentivizes operators to address promptly all issues identified during inspections, which helps to further reduce emissions. The e-NGOs supported this additional language in their rebuttal proposals, and Oxy USA appreciates their agreement. EDF's Exhibit VV.

<u>NMED:</u> In its final proposal circulated to the parties on December 22, 2021, Oxy USA included the new proposed language in Paragraph (6) of Subsection C of Section 20.2.50.122. The Department does not agree with this proposal. Oxy USA never proposed this language in any of its testimony, and it is not supported by the record in this matter. The Board should therefore reject this proposal.

<u>NMOGA proposes to insert a date in C(2), and to make other changes in paragraphs (4), (5), and (6):</u>

(2) <u>No later than January 1, 2023,</u> the owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

<u>NMOGA:</u> This change aligns the start date with completion of the inventory.

(4) <u>Within two years of the effective date,</u> the owner or operator's ~~database~~ <u>data systems</u> shall contain the following <u>for each in-service natural gas-driven pneumatic controller:</u>

(a) ~~natural gas-driven~~ pneumatic controller unique 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) if continuous, design annual bleed rate in standard cubic feet per year.

<u>NMOGA:</u> Paragraph (3) of Subsection A of proposed 20.2.50.112 NMAC provides two years to establish the data system. This provision needs to be consistent as data cannot be

recorded until the system is in place. Mr. Smitherman indicated two years would be needed and Ms. Kuehn agreed that NMED's experience is that such systems take more than a year to set up. Bisbey-Kuehn testimony, Transcript 5:1370:3-8; see also Smitherman testimony, Tr. 5:1427:21-5:1428:25; Brown testimony, Tr. 5:1437:19-5:1439:11.

(5) <u>Upon the effective date for the facility in 20.2.50.116 NMAC,</u> the owner or operator of a natural gas-driven pneumatic diaphragm pump shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

<u>NMOGA:</u> This is an LDAR requirement. LDAR on a particular piece of a facility should be started when the facility starts LDAR under proposed 20.2.50.116 NMAC. Piecemeal implementation adds cost, double mobilization, and makes compliance difficult as the full LDAR system is not ready prior to its design and implementation under section 20.2.50.116 NMAC. Smitherman testimony, NMOGA Ex. A1:21:16-39.

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC, <u>applicable to the facility type at which the pneumatic controller is installed on the effective date specified in section 20.2.50.116 NMAC.</u> During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

<u>NMOGA:</u> This is an LDAR requirement. LDAR on a controller at a facility should be started when the facility starts LDAR under proposed 20.2.50.116 NMAC. Piecemeal implementation adds cost, double mobilization, and makes compliance difficult as the full LDAR system is not ready prior to its design and implementation under section 20.2.50.116 NMAC. Smitherman testimony, NMOGA Exhibit A1:21:16-39.

D. Recordkeeping requirements:

(1) Non-emitting pneumatic controllers and diaphragm pumps are not subject to the recordkeeping requirements in Subsection D of 20.2.50.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller

count for all controllers at all of the owner or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of natural gas-driven pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each natural gas-driven pneumatic controller. The record shall include the following:

(a) pneumatic controller unique identification number;

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) name of the person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;

(f) record of the controller type, bleed rate, or bleed volume required in Subparagraphs (b), (c), (d), and (e) of Paragraph (4) of Subsection C on 20.2.50.122 NMAC.

(g) maintenance date and maintenance activity; and

(h) a record of the justification and certification required in Subparagraph (c) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic diaphragm pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least ninety-five percent 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 or inhouse engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

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

NMED: Subsection D of Section 20.2.50.122 sets forth recordkeeping requirements for pneumatic controllers and pumps. Pneumatic devices that do not use natural gas or other hydrocarbon gas as motive force are exempt from the monitoring requirements. Owners and operators are required to maintain a total count of all emitting and non-emitting pneumatic controllers at affected facilities that commenced operation prior to the effective date of Part 50 and maintain a total count of units necessary for safety or process purposes that cannot be met without emitting VOC. Owners and operators of affected controllers must develop and record the schedule and compliance status for each controller so that it meets the compliance deadlines.

Owners and operators must maintain an electronic record for each affected controller or pump that contains the ID number, controller type, design continuous bleed rate for continuous controllers, bleed volume per bleed for intermittent controllers, each controller's design annual bleed rate, inspection dates, name of personnel conducting the inspection, AVO inspection result, AVO level discrepancy in continuous or intermittent bleed rate, maintenance date and activity, and a record of the justification for use of a controller with a bleed rate greater than six scfh. Electronic records must be maintained for natural gas-driven pneumatic pumps and the associated pump numbers that have emission rates greater than zero. The record must include the dates of operation for any pump operating less than 90 days per calendar year; any control device designed to achieve at least 95% emission reduction, including an evaluation or the manufacturer specifications indicating percent reduction the control device is designed to achieve; and documents of engineering assessments and certifications from a qualified professional engineer stating that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. No party provided comments on this proposal. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 127, 130-38; Tr. Vol. 7, 2036:19 – 2038:5.

<u>NMOGA proposes to insert the word "historic" in D(2):</u>

(2) The owner or operator shall maintain a record of the total <u>historic</u> controller count for all controllers at all of the owner or operator's affected facilities that

commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

NMOGA: The word is added for consistency with NMOGA's proposed changes.

NMOGA proposes an added sentence at the end of D(4):

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller. On or before January 1, 2024, January 1, 2027 and January 1, 2030, the owner or operator shall make and retain the compliance demonstration set forth in Paragraph (4)(c) of Subsection B of 20.2.50.122 NMAC.

NMOGA: This provision added to memorialize the compliance demonstration contemplated in new paragraph (4)(c) of Subsection B of 20.2.50.122 NMAC.

NMOGA proposes to add a sentence at the end of D(6):

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC. This demonstration shall be completed by July 1, 2023 for controllers with a bleed rate greater than six scf/hr and as necessary for controllers with a bleed rate less than or equal to six scf/hr.

NMOGA: This language harmonizes recordkeeping provision with schedule for phase out of High Bleed Controllers while allowing for designation of smaller units, as indicated in Ms. Kuehn's testimony. Bisbey-Kuehn testimony, Tr. 7:2040:17-7:2041:9.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.122 NMAC - N, XX/XX/2021]

NMED: Subsection E of Section 20.2.50.122 requires owners and operators to comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 127, 130-38.

Estimated Costs and Emissions Reductions Resulting from Section 20.2.50.122

ERG estimated the overall emission reductions from Section 20.2.50.122 to be 31,347 tpy of VOC. ERG estimated that these reductions would be achieved at an overall cost effectiveness of $2,475 per ton of VOC. A detailed explanation of this analysis is provided in NMED Exhibit 32, pp. 131-37; NMED Exhibit 95 – Pneumatics Reductions and Costs Spreadsheet; and Tr. Vol. 7, 2023:14-23.

NMOGA argued that "the Emission Factors for intermittent controllers are incorrect in ERG study, and costs associated with modifications are understated. Cost per ton of VOC in ERG reports is significantly understated," referencing the memo attached to its direct testimony 'Valor Memo - Pneumatic Controllers 20.2.50.122 Emission Factors.' This two-page memo lists several recent studies and claims that their data is "much more robust than the original EPA data" and states that Colorado used a different emission factor in its February rulemaking. However, the memo provides no details regarding these studies, the data they present, or how those data were analyzed and applied. *See* NMED Rebuttal Exhibit 1, pp. 86-87.

The Board should reject NMOGA's claim that the emission factors used are incorrect. NMOGA would apparently have the Board conduct a comprehensive literature review of studies on pneumatic emission factors and assign a new emission factor for intermittent controllers based on that review in the context of this rulemaking. Such an undertaking is not appropriate in a rulemaking proceeding such as this and is far beyond the scope of this proceeding. The Board should find that NMED appropriately relied upon the well-established emission factors accepted by other state agencies and EPA, and required for federal greenhouse gas reporting to estimate the emission reductions and costs of this proposed rule. *See* NMED Rebuttal Exhibit 1, p. 87. The Board should find that NMED's estimated costs associated with Section 20.2.50.116 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

<u>IPANM proposed significant changes throughout Section 122 in its redline at pp. 7-11:</u>

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:
A. Applicability: Natural gas-driven pneumatic controllers and <u>diaphragm</u> pumps <u>permanently</u> located at well sites, tank batteries, gathering and boosting stations, <u>and</u> natural gas processing plants, <u>and transmission compressor stations</u> are subject to the requirements of 20.2.50.122 NMAC, <u>except pumps that operate less than 90 days per calendar year.</u>
B. Emission standards:
(1) A new ~~natural gas-driven pneumatic controller or pump~~ <u>well</u>

production facility, tank battery, gathering and boosting site, or natural gas processing plant shall comply with the requirements of 20.2.50.122 NMAC upon startup, except pumps that operate less than 90 days per calendar year.

(2) ~~An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part~~. A new well production facility, tank battery, gathering and boosting site, or natural gas processing plant shall have non-emitting controllers installed, except as allowed in Paragraph 4 of Subsection E of 20.2.50.122 NMAC

(3) An existing well production facility and tank battery with four or more natural gas-driven pneumatic controllers shall comply with the requirements of 20.2.50.122 NMAC according to the ~~following~~ schedule in Table 1 below:

Table 1 – WELL SITES, TANK BATTERIES, GATHERING AND BOOSTING STATIONS

Total Historic ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production by January 1, 2024	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production by January 1, 2027	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production by January 1, 2030
> 75%	80%	85%	90%
> 60-75%	80%	85%	90%
> 40-60%	65%	70%	80%
> 20-40%	45%	70%	80%
0-20%	25%	65%	80%

Table 2 – TRANSMISSION COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75%	80%	95%	98%
> 60-75%	80%	95%	98%
> 40-60%	65%	95%	98%
> 20-40%	50%	95%	98%
0-20%	35%	95%	98%

(a) For purposes of this section, a “Non-Emitting Facility” means a facility with only Non-Emitting Controller except as allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(b) Except as provided in 20.2.50.122.B.(3)(c) or (d) NMAC,

owners or operators of existing well production facilities and associated tank batteries shall by January 1, 2023:

(i) Determine the Historic Facility Production for each existing well production facility by summing the total liquids productions (summing total barrels of oil and water produced through the well production facility) for the calendar year 2020. For a well production facility that does not have a full calendar year of data, then the owner or operator may use 2021 data or an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

(ii) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced construction prior to the effective date.

(iii) Calculate the Facility Percent Production for each existing facility by dividing the Historic Facility Production by the Total Historic Production.

(iv) Determine the Total Historic Non-Emitting Facility Percent Production by summing the Facility Percent Production for each Non-Emitting Facility as defined in Subparagraph (5)(a) of Subsection B of 20.2.50.122 NMAC. The Total Historic Non-Emitting Facility Percent Production determines an owner or operator's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production as set forth in Table 1, except as provided in subparagraphs (c) or (d) of this Paragraph (3).

(v) Owners and operators must demonstrate compliance with Table 1's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production through any combination of retrofitting well production facilities (and associated tank batteries) to use non-emitting controllers or plugging and abandoning an existing well production facility and emptying and decommissioning an associated tank battery. A tank battery that is decommissioned and moved to another location is a new facility for purposes of 20.2.50.122.B.(1) and (2) NMAC.

(c) In lieu of the demonstration required by 20.2.50.122.B.(3)(b) NMAC, an owner or operator may demonstrate that its total oil and natural gas production subject to Part 50 averages fifteen barrels of oil equivalent (using a 6 mcf to 1 barrel oil equivalent for natural gas) or less per well per day annual average. To calculate total oil and natural gas production subject to Part 50, an owner or operator must sum all affected oil and natural gas production in calendar year 2020 in barrels of oil equivalent, divide by 365, and divide by the number of affected wells producing hydrocarbons that the owner or operator operated in 2020.

(d) If an owner or operator meets at least seventy-five percent Total Non-Emitting Facility Percent Production by January 1, 2025, table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC does not apply and the owner or operator shall maintain the Total Non-Emitting Facility Percent Production at seventy-five percent or greater thereafter.

~~(4) Standards for natural gas-driven pneumatic controllers.~~

~~(a) new pneumatic controllers shall have an emission rate of zero.~~

~~(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero within two years of the effective date of this Part.~~

~~(c) existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:~~

~~(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or~~

~~operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.~~

~~(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.~~

~~(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.~~

~~(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.~~

~~(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator is not subject to the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.~~

(vi) if ~~after January 1, 2027~~, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator may submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(d) a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional or inhouse engineer.

(e) Temporary pneumatic controllers that emit natural gas and are used for well abandonment activities or used prior to or through the end of flowback, and pneumatic controllers used as emergency shutdown devices located at a well site, are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(f) Temporary or portable pneumatic controllers that emit natural gas and are on-site for less than 90 days are not subject to the requirements of Subsection B of 20.2.50.122 NMAC.

(5) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at natural gas processing plants shall have a~~n~~ <u>designated natural gas</u> emission rate of zero.

(b) new pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations with access to commercial line electrical power shall have a~~n~~ <u>designated natural gas</u>

emission rate of zero.

(c) existing pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or transmission compressor stations with access to commercial line electrical power shall have a~~n~~ designated natural gas emission rate of zero within ~~two~~ three years of the effective date of this Part.

(d) owners and operators of pneumatic diaphragm pumps located at well sites, tank batteries, gathering and boosting stations, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic diaphragm pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic diaphragm pump emissions to the control device within ~~two~~ three years of the effective date of this Part.

(e) If an owner or operator's remaining natural gas pneumatic controllers, or if three years after the effective date, an owner's or operator's existing natural gas pneumatic diaphragm pumps at a site without commercial line power, are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force are not subject to the monitoring requirements in Subsection C of 20.2.50.122 NMAC.

(2) The owner or operator of a facility with one or more natural gas-driven pneumatic controllers subject to the deadlines set forth in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller shall, on a monthly basis, conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance ~~(such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain~~ on the natural gas-driven pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) ~~The owner or operator's database shall contain the following~~ For any natural gas-driven pneumatic controller remaining in operation after January 1, 2030, the owner or operator shall maintain an inventory of natural gas driven pneumatic controllers containing the following:

(a) natural gas-driven pneumatic controller unique 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) if continuous, design annual bleed rate in standard cubic feet per year.

(5) The owner or operator of a natural gas-driven pneumatic diaphragm pump that emits natural gas to the atmosphere shall, on a monthly basis, conduct an AVO or OGI inspection and shall also inspect the pneumatic pump and perform necessary maintenance, ~~and maintain the pneumatic pump according to manufacturer specifications~~ to ensure that the VOC emissions are minimized.

(6) The owner or operator of a natural gas-driven pneumatic controller shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrument inspections, operators shall use RM 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the event, and the monitoring data entry shall be made in accordance with the requirements of this Part.

(8) The owner or operator shall monitor liquids production through each well production facility or tank battery.

(9) The owner or operator shall monitor total oil and gas production though each well production facility.

(6) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Non-emitting pneumatic controllers and diaphragm pumps are not subject to the recordkeeping requirements in Subsection D of 20.2.50.122 NMAC.

(2) ~~The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.~~ The owner or operator shall maintain a record of each existing well production facility and associated tank batter, its total liquids production, the total oil and gas production at all existing well production facilities subject to Part 50, whether the well production facility and associated tank battery is a Non-Emitting Facility, and the 2020 liquid throughput for each well production facility and associated tank battery. An owner or an operator complying with Table 1 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Non-Emitting Facility Percent Production as set forth in Paragraph (3)(b) of Subsection B except substituting the calendar year's production for the 2020 production. The owner or operator of existing well production facilities complying with the limitation on daily average production using the procedures in Paragraph (3)(c) of Subsection B shall calculate its daily average production using the procedures in Paragraph (3) substituting the calendar year 2020.

(3) The owner or operator shall maintain a record for each existing gathering and boosting site and natural gas processing plant of the total count ~~of natural gas-driven pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC~~ of all emitting and non-emitting pneumatic controllers. An owner or operator shall calculate the percentage of non-emitting controllers for each calendar year from 2022 through 2031, excluding controllers under Paragraph (5) or (7) of Subsection B of 20.2.50.122 NMAC.

(4) The owner or operator of a natural gas-driven pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. ~~The owner or operator shall keep a record of the compliance status of each subject controller.~~

(5) The owner or operator shall maintain an electronic record for each natural gas-driven pneumatic controller. The record shall include the following:

(a) pneumatic controller unique identification number;

(b) time and date stamp, including GPS of the location, of any monitoring;

(c) name of the person(s) conducting the inspection;

(d) AVO or OGI inspection result;

~~(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;~~ …………

IPANM: NMED proposed 20.2.50.122 NMAC applies to natural gas-driven pneumatic controllers and pumps, that are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations. NMED's proposal is intended to reduce emissions from pneumatic controllers by replacing high bleed controllers with low bleed or zero bleed models, using instrument air, rather than natural gas, to drive controllers. Pneumatic controllers are "critical for the safe and efficient operation of process equipment in remote areas." IPANM Ex. 2 at 13 (Davis Direct). A pneumatic controller is a "process control device used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves." The controllers can regulate safety shut-downs, positions, fluid levels, pressure, temperature, and flow rate in oil and natural gas production and processing.

IPANM opposed the Department's proposal because it is difficult to cost effectively replace gas-driven pneumatic controllers that are currently used. IPANM Ex. 2 at 13 (Davis Direct). Mr. Davis testified that instrument air is the best solution for running pneumatic controllers in terms of performance and reliability; however, it is extremely difficult to operate an instrument air system without line power, which is largely unavailable as most sites in Northwest New Mexico. IPANM Ex. 2 at 13. (Davis Direct). Mr. Smitherman commented that given the very remote locations of these pads, "it is highly impractical to require something other than natural gas operated pneumatics devices in these situations." NMOGA Appendix A1 at 28-29 (Smitherman Direct). Mr. Davis testified that IPANM members attempted to use other means to install instrument air systems for sites without line power, such as a solar power system. IPANM Ex. 2 at 14 (Davis Direct). Mr. Davis expressed concern about the reliability of solar power and the cost of installation. IPANM Ex. 2 at 14 (Davis Direct). IPANM also attempted a pilot project with rotary electric actuators and still had a number of malfunctions, including an increase in the amount of gas sent to the tanks due to the actuators not being able to close quickly enough. IPANM Ex. 2 at 15 (Davis Direct).

IPANM and NMOGA suggested an approach, similar to Colorado, that couples regulations to phase-out gas-driven pneumatics with a percentage of liquid production approach and use of intermittent bleed pneumatic controls. IPANM Ex. 2 at 15 (Davis Direct); NMOGA Appendix A1 at 29 (Smitherman Direct). NMOGA suggested the Department focus on larger sites that are more likely to have line power, making a transition to instrument air more cost effective. NMOGA Appendix A1 at 29 (Smitherman Direct). Oxy also recommended basing a phase out on historic liquids production, rather than number of controllers at a specific site. Oxy Ex. 2 at 14 (Holderman Direct). This would mean that the controllers that are actuated more frequently are the first to be phased-out. Oxy Ex. 2 at 14 (Holderman Direct). GCA encouraged the Department to treat intermittent pneumatic controllers similarly to non-emitting controllers recognizing that intermittent controllers only emit during the actuation cycle. GCA Ex. 17 at 5 (Carr Direct).

EDF encouraged NMED to move up the proposed retrofit schedule of gas-powered pneumatic controllers. CAA testified in support of zero emission pneumatic controllers and highlighted solar and electric technology that make this possible. CAA also believes that these methods are cost-effective to implement through retrofits. CAA proposed modifications that would accelerate the compliance timeline, increase the fraction of non-emitting controllers by a fixed percentage, and provide an incentive to operators who convert 75% of their controllers early.

NMED revised the section in response the comments received from all the parties. NMED Rebuttal Ex. 2. NMED disagreed with utilizing the “Colorado Approach” of regulating pneumatic controllers based on historic production volume, because that approach was based on already reduced emissions from previous regulatory efforts. NMED Rebuttal Ex. 1 at 83-84 (Bisbey-Kuehn/Palmer Rebuttal). NMED’s revisions include allowing for exclusion from 20.2.50.122 NMAC for temporary and portable pneumatic controllers that are used in specific activities. NMED Rebuttal Ex. 2 at 30.

In rebuttal, IPANM and NMOGA reiterated their concerns with the expense and feasibility of instrument air installations at remote well pads. Particularly, solar is not as reliable as the Department assumed it to be. IPANM Ex. 10 at 17-18 (Davis Rebuttal); NMOGA Ex. 42 at 8 (Meyer Rebuttal); GCA Ex. 32 at 6 (Davis Rebuttal). Oxy’s rebuttal focuses particularly on the difficulty to achieve the stated timelines in the rule. Stating that NMED should instead consider using the previously proposed historic production amounts to determine implementation timelines. Oxy Rebuttal Ex. 2 at 5-6 (Holderman Rebuttal). GCA advocates strongly in its rebuttal that intermittent pneumatic controllers should be part of the solution for reducing emissions. GCA Ex. 32 at 8 (Davis Rebuttal). During the period of rebuttal testimony, CAA came to an agreement with Oxy. CAA Ex. 23 at 2 (McCabe Rebuttal).

The Oxy-CAA agreement included support for an accelerated replacement schedule of venting pneumatic controllers at well production facilities. CAA Ex. 23 at 2 (McCabe Rebuttal). Notably, in agreeing to an accelerated replacement schedule, CAA supports the switch to a liquid production metric for retrofit timing. Id. at 5.

NMED testified that the basis for the proposed requirements for pneumatics is from Colorado’s Regulation 7 with some slight adjustments. Tr. Vol. 7, 2022:2-23 (Palmer). NMED testified that the proposed regulation allows for similar flexibility as Colorado, where operators can prioritize high-producing production facilities. There is also a built in “off-ramp” for owners meeting a 75% target for nonemitting controllers by January 1, 2025. If after January 1, 2027, there are still units that are not cost-effective to replace, an owner can submit an analysis to NMED on the retrofit costs. Tr. Vol. 7, 2022:24-2023:13 (Palmer). NMED testified that much of the testimony from certain parties proposed a regulatory approach to pneumatic controllers that was adopted in

Colorado; however, NMED explained that this was inappropriate for New Mexico. Tr. Vol. 7, 2025:14-25 (Bisbey-Kuehn). Particularly, NMED testified that Colorado already had requirements in place for pneumatic controllers that has already achieved significant emission reductions whereas New Mexico has no such system in place and is thus starting in a different position. Tr. Vol. 7, 2026:12-2027:15 (Bisbey-Kuehn). NMED provided clarification that January 1, 2023, would be the date that some of the requirements would need to be met for creating a controller count list. Tr. Vol. 7, 2042:8-11 (Bisbey-Kuehn).

CAA testified at the hearing about a joint proposal between CAA, EDF, CCP, NAVA and Oxy that was also supported by NPS. Tr. Vol. 7, 2057:16-22 (McCabe). CAA explained that the Colorado rule, which was adopted with unanimous industry support, is a much faster approach than New Mexico's. Tr. Vol. 7, 2066:18-23 (McCabe). CAA, EDF, CCP, NAVA and Oxy explained that their joint proposal would result in a more rapid transition to zero emission controllers and would also ensure that the phase-out occurs in a more efficient and fair way. Tr. Vol. 7, 2068:20-25 (McCabe). CAA emphasized that the joint proposal is based on liquids produced rather than controller counts. Tr. Vol. 7, 2069:11-13 (McCabe).

NMOGA testified that it accepted the NMED's pneumatics proposal because it balances the needs of emissions reductions with the realities of the oil and gas business in New Mexico. Tr. Vol. 7, 2109:5-13 (Smitherman). IPANM testified that a production phase-out approach, rather than a controller count approach, is an appropriate path forward. Tr. Vol. 7, 2189:1-4 (Davis). IPANM also testified that the Colorado Regulation has flexibility for small producers that IPANM felt was critical to be in the Ozone Rule for smaller producers and lower-producing wells. Tr. Vol. 7, 2189:4-13 (Davis). IPANM discussed the importance of also using intermittent controllers that do not continuously bleed natural gas during normal operations, but bleeds back the actuation gas after the actuation has taken place. Tr. Vol. 7, 2189:14-25 (Davis). IPANM also highlighted how much work is devoted to instrument air installations. Such an installation usually requires design and packaging of the air package, delivery, trenching in air lines and power, and determining necessary setbacks from other equipment. Tr. Vol. 7, 2191:19-2192:3 (Davis).

IPANM reiterated its concerns about getting commercial line power to many of its remote sites. Significant areas in Northwest New Mexico lacked reasonably accessible commercial line power. There are significant concerns with lines, rights of way and infrastructure in general to be able to have line power on a site. Tr. Vol. 7, 2192:4-2193:13 (Davis). IPANM's major concern with this part of the Ozone Rule surrounds fairness to smaller producers and not forcing them through the regulation to close or shut-in their wells earlier than anticipated. Tr. Vol. 7, 2199:2-2200:8 (Davis); Tr. Vol 7, 2201-24-2202:6 (Davis). Oxy also testified to the difficulties of getting line power out to certain areas of the state as being potentially cost-prohibitive when trying to transition to non-emitting pneumatic controllers. Tr. Vol. 7, 2212:9-23 (Holderman). Kinder Morgan testified that it supported NMED's proposed Ozone Rule as described in NMED's earlier testimony. Tr. Vol. 7, 2282:1-7 (Nolting). EDF proposed a shorter timeframe for transitioning to non-emitting pneumatic controllers. EDF believes its proposal is both economically reasonable and practical. Tr. Vol. 10, 3226:6-18 (Alexander).

NMED rebutted the joint proposal from Oxy and NGO's by stating it is still inappropriate for New Mexico because NMED did not have a current methodology to determine the total historic percentage of liquids produced. Tr. Vol. 7, 2239:12-23 (Bisbey-Kuehn). EDF testified about three studies it considered to support the requirements surrounding pneumatic controllers and how the best way to reduce emissions from pneumatic controllers is to replace them with zero emitting devices. Tr. Vol. 7, 2224:18-24 (Lyon). [See IPANM proposed SOR 193-238 for more citations in this detailed history of the evolution of this section.]

NMED responded to IPANM's proposal to include an exception for lower producing wells by saying that it would exempt 269 out of 324 well operators who have oil production. Tr. Vol. 7, 2243:5-2 (Palmer). The Board should find that NMED's proposed rule is not appropriate and find that IPANM's production-based approach in the Proposed Final 20.2.122 NMAC is appropriate.

20.2.50.123 STORAGE VESSELS

NMED:

Description of Equipment or Process

Storage vessels, commonly referred to as “storage tanks” or “tanks,” are used throughout the oil and gas industry for storing a variety of liquids including crude oil, condensates, and produced water. These tanks are associated with oil and gas production, gathering, processing, and disposal and are significant sources of VOC emissions. Storage vessels can be installed as a single unit or in a grouping of similar or identical vessels, commonly referred to as a “tank battery.” The reason for temporary storage is for feasibility of takeaway via pipeline or truck. NMED Exhibit 32, pp. 138-39.

While underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed, and any oil and water remain together) or a three-phase separator (where the associated gas is removed, and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released as vapors in the storage vessels. *Id.* at 139.

Hydrocarbon emissions from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into a storage vessel at atmospheric pressure from a processing vessel (e.g., a separator) operated at a higher pressure. In general, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and the expansion and contraction of stored fluids resulting from increased or decreased pressures associated with environmental and weather-related fluctuations. Working losses occur when vapors are displaced due to the emptying and filling of a storage vessel. *Id.*

The mass of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming off of the oil. The composition of the vapors from storage vessels varies, and the largest component is methane, but may also include ethane, butane, propane, and hazardous air pollutants such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane. *Id.* at 140.

Control Options for Storage Vessels

The methods typically used to reduce VOC emissions from storage tanks are: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled or recovered (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite; and/or (2) route emissions from the storage vessel to a combustion device. NMED Exhibit 32, pp. 140-43.

Rule Language

The proposed requirements in Section 20.2.50.123 are based on similar rules for new and existing storage vessels in Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, and NSPS Subpart OOOOa. *See* NMED Exhibit 32, pp. 146-47; NMED Exhibits 37, 38, and 39.

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels with a PTE equal to or greater than three tpy of VOC in multi-tank batteries, and existing storage vessels with a PTE equal to or greater than four tpy of VOC in single tank batteries are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels. Storage vessels associated with produced water management units are required to comply with this Section to the extent specified in Subsection B of Section 20.2.50.126 NMAC.

NMED: Subsection A of Section 20.2.50.123 specifies the storage vessels to which Part 50 applies. Applicability is based on the PTE of the storage vessel, which is further delineated based on whether the vessel is classified as new or existing, and for existing storage vessels, whether the vessel is part of a multi-tank battery, or a single tank battery. New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels with a PTE equal to or greater than 3 tpy in multi-tank batteries, and existing storage vessels with a PTE equal to or greater than 4 tpy in single tank batteries must comply with the requirements of Section 20.2.50.123. The Department has also proposed a sentence at the end of Subsection A to align the requirements in Section 20.2.50.123 with the requirements for produced water management units in Section 20.2.50.126.

Initially, the Department proposed that storage vessels with an uncontrolled PTE equal to or greater than 2 tpy were required to comply with this Section. *See* NMED Ex. 32, pp. 144, 146-47. NMOGA proposed to revise the threshold for existing storage vessels to 6 tpy. The Department did not agree with that proposal, based on the higher cost effectiveness for controlling the smallest tanks, but in its rebuttal testimony revised its proposal to raise the applicability threshold for existing storage tanks to 3 tpy. *See* NMED Rebuttal Ex. 1, p. 91. NMOGA presented testimony demonstrating that storage vessels in single tank batteries in New Mexico are particularly problematic with respect to the cost-effectiveness of retrofitting or replacing these tanks due to their lack of available headspace to moderate demands on the control system combined with the typical age and pressure ratings of such tanks in New Mexico. *See* Tr. Vol. 9, 2094:11 – 2914:17. NMOGA witness Adam Meyer pointed out that the Department's cost analysis had not taken into account certain costs associated with replacing these tanks. *See* Tr. Vol 9, 3035:15 – 3036:21, 3092:10 – 3094:16. Based on the single tank spreadsheet prepared by NMED witness Mr. Palmer and submitted at the hearing as NMED Rebuttal Exhibit 29, a threshold of 3 tpy for these tanks results in a cost effectiveness of $9,176/ton, which NMED agrees is on the high side. *See* Tr. Vol 9, 3092:10 – 3094:16.

While NMOGA's proposed 6 tpy threshold would result in a cost effectiveness of $4,558/ton, it would also leave far more storage vessels unregulated resulting in significantly fewer emissions reductions. *See* Tr. Vol. 9, 3034:8-24. NMED has proposed a threshold of 4 tpy for existing storage vessels in single tank batteries which results in a cost effectiveness of $6,876/ton. NMED Rebuttal Exhibit 29.

The Board should adopt this proposal because it strikes a reasonable balance between the costs to industry and the emissions reductions necessary to effectuate the purpose of the statute. The Department did agree with a proposal by NMOGA to allow averaging among storage vessels that vapor manifolded together to determine an individual vessel's PTE for purposes of determining applicability of this Section. The Board should adopt this proposal for the reasons stated in NMED Rebuttal Ex. 1, p. 92. [Oxy USA's earlier proposed edits in this section are not part of its final proposal.]

The use of PTE to determine applicability of air quality regulations and permit requirements is a common and long-standing practice utilized by state and federal air quality regulatory agencies. The use of actual emissions to determine applicability is not acceptable, as that calculation is based on previous years' records of the operation of a source, which may not be representative of a source's future operations or emissions. Because actual emissions can change year to year depending on numerous factors (e.g., economics, regulatory requirements, political decisions, consumer demand, market conditions), that measure is not a reliable or representative emission rate with respect to determining applicability under this Section. PTE is a source's maximum capacity to emit an air pollutant under its physical and operational design, and is a much more accurate and reliable estimation of the source's emissions. NMED Rebuttal Ex. 1, pp. 91-92.

[NMOGA's earlier proposed revisions allowing emissions to be calculated using "generally accepted methods" are not part of its final proposal.] "Generally accepted methods" are undefined, and thus impossible for the Department to evaluate. Methods for estimating PTE must be approved by the Department, which is consistent with the rest of this Part where the Department requires approval of a proposed technology or monitoring strategy. The Department has publicly available information such as permitting guidance and calculation guidance that may be used to calculate PTE. Owners and operators may also consult with the Department to confirm acceptability of emission calculation methods. *Id.* at 92.

NMOGA earlier proposed to exempt sources subject to other federal emission standards from the requirements of this Section. While the current federal requirements represent important emissions reductions (assuming widespread compliance with those requirements), they do not go far enough in reducing emissions, as evidenced by the continued rising ozone concentrations in New Mexico. In accordance with the statutory mandate in the AQCA, NMED proposed more stringent emission control requirements than those provided under the federal regulations for storage vessels. *Id.* at 92-93.

CDG proposes changes for clarification:

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels ~~in multi-tank batteries~~ with a PTE equal to or greater than three tpy of VOC in multi-tank batteries, existing storage vessels ~~in single-tank batteries~~ with a PTE equal to or greater than four tpy of VOC in single-tank batteries are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels.

CEP also proposes changes to Section A:

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC and, existing storage vessels ~~in multi-tank batteries~~ with a PTE equal to or greater than three tpy of VOC, ~~and existing storage vessels in single tank batteries with a PTE equal to or greater than four tpy of VOC~~ are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels.

NMOGA also proposes two changes to Section A:

A. Applicability: New storage vessels with a PTE equal to or greater than two tpy of VOC, existing storage vessels in multi-tank batteries with a PTE equal to or greater than three tpy of VOC, and existing storage vessels in single tank batteries with a PTE equal to or greater than six ~~four~~ tpy of VOC are subject to the requirements of 20.2.50.123 NMAC. Storage vessels in multi-tank batteries manifolded together such that all vapors are shared between the headspace of the storage vessels and are routed to a common outlet or endpoint may determine an individual storage vessel PTE by averaging the emissions across the total number of storage vessels. Storage vessels at produced water management units are exempt from this section except as provided in Subsection B of 20.2.50.126 NMAC.

NMOGA: The Board should adopt NMED's storage vessel proposal, except that the threshold for existing single storage vessels should be increased to 6 TPY. NMOGA generally supports the Department's proposal for controlling storage vessels under 20.2.50.123 NMAC. NMOGA's primary remaining concern at the close of hearing was the proposed 3 tpy applicability threshold for existing single tank. As the evidence demonstrates, there are critical differences between single tanks and multi-tank batteries that make regulation at the 3 tpy threshold economically unreasonable. After further discussion with NMED and review of the technical evidence, NMED has proposed a 4 tpy threshold for these tanks in its latest draft, which is positive movement. NMOGA continues to believe that a 6 tpy threshold is appropriate for these tanks.

According to the testimony of Mr. Meyer, unlike multi-tank batteries, single tank batteries have limited headspace to allow accumulation of vapors. Whereas multi-tank batteries have adequate headspace to allow pressure buildup within the tank as emissions are slowly processed through the control, a single-tank battery's control must be able to process displaced vapors entering the headspace immediately through the control device. This behavior demands that owners and operators install larger, more expensive combustors on single tank batteries than would otherwise be required. *See generally* Tr. 9:2907:7- 24; 2912:11-2913:9 ("there are instances where you actually do need bigger equipment than is usually – than is reasonably thought to be needed. You know, again a lot of times if you have tanks with low vapor space, head space, you do need a larger combustor, you know, many times.")

The challenges from lack of headspace are compounded in New Mexico by the age and rating of many of the single tanks in service. According to Mr. Meyer, many of these tanks are older and rated for either "atmospheric" or very low pressure instead of the 16 ounces more typical of modern tanks. Tr. 9:2913:10-23. This means that the tanks can't handle much, if any, internal pressure before they must vent. It is generally not possible to control atmospheric or low pressure rated tanks, and these tanks will most likely require replacement to meet NMED's proposed standards. Tr. 9:2914:17-9:2915:2.

Due to the headspace and aging complications, the cost-per-ton of controlling single tank batteries is higher than prior NMED estimates indicated. As Mr. Meyer stated, "if you consider the rules in its entirety, hydrocarbon liquid -- hydrocarbon vapor capture during truck loadout, potential for larger combustor or control device, replacing of tanks, all these things add up, you could have a significant cost associated with especially the smaller tank, single standalone tank batteries." Tr. 9:2915:17-24; *see also* Tr. 9:2925:8-23 (responding to question from Vice Chair Trujillo-Davis).

Mr. Palmer and Mr. Meyer presented competing views of the costs of controlling single tank batteries. Mr. Palmer testified that the retrofit costs in Mr. Meyer's spreadsheet were high because they exceeded the cost of replacing the tank. Based on this observation, Mr. Palmer conducted his own analysis and replaced the allegedly excessive retrofit costs with the relatively lower costs for replacing the tank. Tr. 9:3035:15-9:3036:21. Mr. Meyer reviewed Mr. Palmer's cost-per-ton estimate and the underlying data, including the EPA's explanation of retrofit costs. Mr. Meyer determined that the CTG cost for "storage vessel retrofit, as they called it, that – in 2012 year, the $68,000 was associated with new piping, new headers, basically to bring the tank vapors to the control device." Tr. 9:3092:10-24. Mr. Meyer testified that the $68,000 (now about $72,000 in 2019$) would also have to be incurred for tank replacements and that Mr. Palmer's calculation erroneously excluded these costs. Moreover, since many single tanks will require replacement, Mr. Meyer testified that the $18,000 incurred for acquisition and installation of a new tank also needed to be included. These revisions increase the cost to approximately $101,736 for single tanks, bringing the "cost per ton of VOC reduced" to around $9,167/ton VOC at a 3 tpy level. Tr. 9:3093:7-25; 9:3094:1-5; NMOGA Exhibit 62. Regulation at this cost-per-ton would be particularly difficult for small operators who are more likely to own aging existing single storage vessels.

The 4 tpy threshold is also excessively costly at $6,890/ton VOC reduced. The following table summarizes available cost-per-ton figures for the provisions of 20.2.50 NMAC and demonstrates that, barring consideration of turbine VOC controls, the 4 tpy threshold for existing single tank batteries is more costly than any other proposal on an average cost-per-ton basis.

Emissions Source	Average $/Ton	Exhibit
Compressor Seals Turbines	$ 319.68	NMED 66
Hydrocarbon liquid transfers	$ 535.79	NMED 84
Engines - VOC	$ 990.00	NMED 57
Reciprocating Compressor Seals	$ 1,085.21	NMED 64
Glycol Dehydrators - Condensor	$ 2,033.96	NMED 77
Engines - NOx	$ 2,247.00	NMED Rebuttal 25
Storage Vessels (Average)	$ 2,695.00	NMED Rebuttal 28
Pneumatics	$ 2,744.71	NMED 95
Heaters - NOx	$ 3,010.00	NMED Rebuttal 27
Turbines - NOx	$ 3,214.00	NMED Rebuttal 26
LDAR - wellhead	$ 3,505.66	NMED 69
Glycol Dehydrators - Combustion	$ 3,919.63	NMED 77
Existing tank – 6 tpy	$ 4,593.00	NMOGA 62/NMED Reb. 28
LDAR - Non-wellhead	$ 5,099.99	NMED 69
Existing single tank – 5 tpy	$ 5,729.65	NMOGA 62
Existing single tank – 4 tpy	$ 6,890.00	NMOGA 62/NMED Reb. 28
Turbines - VOC	$ 9,608.25	NMED 59

The cost-per-ton of controlling VOC emissions from turbines is an outlier at $9,608.24/ton and should not be used to establish the ceiling of cost-effectiveness in this rule or to justify the 4 tpy threshold for existing single tanks. Turbines are expensive units, located at large facilities where millions of dollars have been invested in infrastructure and equipment. As Mr. Brindley testified, these “very expensive and very large” units range anywhere from $7 million to in excess of $10 million. Tr. 6:1806:12-14; 6:1807:4-17. Contrarily, existing single tanks are commonly associated with single well sites that are past their production prime. These sites are often owned and operated by small, independent operators who cannot afford excessively expensive controls.

Testimony of Meyer, Tr. 9:2914:10-17

Eliminating the VOC turbine controls from consideration, the next highest cost-per-ton is for existing single tanks at the 4 tpy and 5 tpy threshold, which cost $6,890 and $5,792.64 per ton respectively. This understates the impact on a small operator, who will be required to spend the full cost (almost $150,000, NMOGA Ex. 61) upon installation and may not be able to get financing. Bisbey-Kuehn testimony, Tr. 3:879:16-20 ("Small and large companies may operate within the same industrial sector; however, the differences in how these companies operate in their ability to finance, and its capital, and the well size can affect their operations."). The costliest measures of 20.2.50 NMAC should not be imposed upon equipment commonly used by small operators at low-production facilities. These sources do not warrant such severe regulation.

NMOGA is advocating for an applicability threshold of 6 tons VOC for existing single tanks with a cost-effectiveness of $4,593 per ton. This is an aggressive proposal, and would make the existing single tank standards the costliest standards under 20.2.50 NMAC, with the exception of the $5099.99/ton VOC reduced threshold for leak detection and repair requirements for non-wellhead facilities under 20.2.50.116 NMAC and the turbine standards discussed above. NMOGA believes that a 6 tpy threshold for single-tank tank batteries should be adopted.

NMOGA proposes to add the last sentence in Section 123A to clarify how proposed 20.2.50.123 and 20.2.50.126 NMAC work together for storage vessels at produced water management units. As the testimony showed, storage vessels or tanks at these facilities have difficult to predict potential to emit, may have unrealistically high potential to emit compared to actual VOCs lost from the process, and may require extensive supplemental fuel to control, with adverse ozone effects. Therefore, the Board should address these storage vessels first under 20.2.50.126. If 20.2.50.126 determines that section 20.2.50.123 controls are appropriate, then they would comply.

B. Emission standards:

(1) An existing storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent according to the following schedule. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

(a) By January 1, 2025, an owner or operator shall ensure at least

30% of the company's existing storage vessels are controlled;

(b) By January 1, 2027, an owner or operator shall ensure at least an additional 35% of the company's existing storage vessels are controlled; and

(c) By January 1, 2029, an owner or operator shall ensure the company's remaining existing storage vessels are controlled.

NMED: Paragraph (1) of Subsection B of Section 20.2.50.123 sets forth the emission standard for existing storage vessels to which this Section applies. Existing tanks must have a combined capture and control of VOC emissions of at least 95%. If a combustion device is used, it must have a minimum design combustion efficiency of 98%. Owners and operators of existing tanks must been these standards on the phased-in schedule set forth in Subparagraphs (a) through (c) of Paragraph (1). The Department proposed adding the phase-in schedule in response to comments from Oxy USA. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148; NMED Rebuttal Exhibit 1, p. 93; and Tr. Vol. 9, 2898:17 – 2900:9, 3030:19 – 3031:3.

(2) A new storage vessel subject to this Section shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup. If a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent.

NMED: Paragraph (2) of Subsection B of Section 20.2.50.123 sets forth the emission standards for new storage vessels. New tanks have the same emission standard as existing tanks, but new tanks must meet this standard upon startup; there is no phased-in compliance schedule. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

(3) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the actual annual VOC emissions decrease to less than two tpy.

NMED: Paragraph (3) of Subsection B of Section 20.2.50.123 provides that the emissions standards in Subsection B cease to apply if the actual annual emissions of an affected storage vessel fall below 2 tpy. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

[NMOGA's earlier proposed revisions in this section to raise the emission threshold from 2 to 4 tpy are not part of its final proposal.] The intent of the rule is to require meaningful reductions in storage vessel emissions; a higher threshold would exempt an unknown number of storage vessels from the control requirements of this Section. NMED Rebuttal Exhibit 1, p. 93.

(4) If a control device is not installed by the date specified in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

NMED: Paragraph (4) of Subsection B of Section 20.2.50.123 allows an owner or operator who fails to install a control device by the specified dates to comply with the emission standards in Subsection B by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device has been installed and operational. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148.

[NMOGA's earlier proposed revisions in this section to allow an operator to reduce production from a well in order to extend the time to comply with the emission standards is not part of its final proposal.]. Limiting a source's throughput or emissions is already an option available to owners and operators and can be achieved by obtaining an air permit with federally enforceable limits. See NMED Rebuttal Exhibit 1, pp. 93-94.

[Oxy USA's earlier proposal to delete this paragraph is not part of its final proposal.] This provision is not a requirement, but rather one option for compliance. NMED has proposed a phased-in compliance schedule as described above to the emission standards in Subsection B of 20.2.50.123 that addresses Oxy's concerns. *Id* at 94.

[NMOGA's earlier proposed revisions to allow requests for extensions to the deadlines of this Section is not part of its final proposal.] The Department proposed revisions to this Section to include a graduated compliance schedule. The proposed compliance deadlines are reasonable; provisions allowing for further extensions are not warranted. *Id.* at 94.

(5) The owner or operator of a new or existing storage vessel with a thief hatch shall ensure that the thief hatch is capable of opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. Any pressure relief device installed must automatically close once the vessel overpressure is relieved.

NMED: Paragraph (5) of Subsection B of Section 20.2.50.123 requires owners and operators new or existing storage vessel equipped with a thief hatch to ensure that the thief hatch can open sufficiently to relieve vessel overpressure, and to automatically close once the vessel overpressure has been relieved. Pressure relief devices must automatically close once the overpressure is relieved. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 144-148 and NMED Rebuttal Exhibit 1, p. 94.

(6) An owner or operator complying with Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

NMED: Paragraph (6) of Subsection B of Section 20.2.50.123 requires that owners or operators that employ a control device to comply with the emission standards of this Section must also comply with the control device operational requirements of 20.2.50.115 NMAC. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48, and NMED Rebuttal Exhibit 1, pp. 94-95.

[Oxy USA's earlier proposed revisions in this section to authorize alternative controls is not part of its final proposal.] Authorization for alternative controls is already incorporated into the definition of Control Device which states "A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part." The Department supports innovative approaches to controlling emissions from low emitting storage vessels. As currently proposed, the rule requires 95% control but does not specify how that control level is to be achieved. The rule does specify that if a combustion control device is used, the combustion device shall have a minimum design combustion efficiency of ninety-eight percent. NMED Rebuttal Exhibit 1, pp. 94-95.

[CDG's earlier proposed revisions to exempt control device requirements where it is technically infeasible to route emissions to a control device without supplemental fuel are not part of its final proposal.] NMED's proposed language in Section 20.2.50.126 addresses the concerns raised by CDG. *Id.* at 95.

C. Storage vessel measurement requirements: Owners and operators of new storage vessels required to be controlled pursuant to this Part at well sites, tank batteries, gathering and boosting stations, or natural gas processing plants shall use a storage vessel

measurement system to determine the quantity of liquids in the storage vessel(s). New tank batteries receiving an annual average of 200 bbls oil/day or more with available grid power shall be outfitted with a lease automated custody transfer (LACT) unit(s).

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels closed and latched during activities to determine the quantity of liquids in the storage vessel(s), except as necessary for custody transfer. Tank batteries equipped with LACT units shall use the LACT unit measurements in lieu of field testing of quantity and quality except in case of malfunction. Nothing in this paragraph shall be construed to prohibit the opening of thief hatches, pressure relief devices, or any other openings or access points to perform maintenance or similar activities designed to ensure the safety or proper operation of the storage vessel(s) or related equipment or processes. Where opening a thief hatch is necessary, owners and operators of new and existing storage vessels shall minimize the time the thief hatch is open.

(2) The owner or operator may inspect, test, and calibrate the storage vessel measurement system either semiannually, or as directed by the Bureau of Land Management (see 43 C.F.R. Section 374.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening a thief hatch if required to inspect, test, or calibrate the vessel measurement system is not a violation of Paragraph (1) of this Subsection.

(3) The owner or operator shall install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(4) The owner or operator shall develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(5) The owner or operator must make and retain the following records for at least two (2) years and make such records available to the department upon request:

(a) date of construction of the storage vessel or facility;

(b) description of the storage vessel measurement system used to comply with this Subsection;

(c) date(s) of storage vessel measurement system inspections, testing, and calibrations that require opening the thief hatch pursuant to Paragraph (1) of this Subsection;

(d) manufacturer specifications regarding storage vessel measurement system inspections and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) records of the annual training program, including the date and names of persons trained.

NMED: Subsection C of Section 20.2.50.123 contains the automatic tank gauging proposal put forward by the eNGOs and Oxy USA in the Joint Proposal, with certain revisions proposed by the Department. In support of the proposal, the Department refers the Board to the testimony presented by CAA on this topic. With regard to the revisions proposed by NMED, Ms. Kuehn stated at the hearing that the Department generally supported the use of a storage vessel measurement system on new storage vessels to determine the quantity of liquids in the vessels. *See* Tr. Vol. 9, 3031:9-23. CAA witness Dr. McCabe testified that CAA wanted the automatic tank gauging requirement to cover opening the thief hatch to check for quality as well as quantity, and that this could be done by employing automatic tank gauging systems and lease automatic custody transfer, or LACT, units. *See* Tr. Vol. 9, 3010:13 – 3011:6. NMOGA witness Mr. Smitherman testified that there are no real options for measuring quality except through use of a LACT unit. *See* NMOGA Exhibit 41, p. 11. Dr. McCabe stated that the intent of the CAA proposal was not to require a LACT unit. *See* Tr. Vol. 9, 3016:5-9. The Department has therefore proposed to revise this provision to prohibit opening thief hatches to check for quantity; to require a LACT unit under specified circumstances; and, where there is a LACT unit, to require use of the LACT unit measurements in lieu of field testing of quantity and quality, except in cases of malfunction. For these reasons, the Board should adopt the Department's proposal.

<u>CEP proposes edits in C and C(1):</u>

C. Storage vessel measurement requirements: Owners and operators of ~~new~~ storage vessels required to be controlled pursuant to this Part at well sites, tank batteries, gathering and boosting stations, or natural gas processing plants <u>constructed on or after the effective date of this Part, and at any facilities that are modified on or after the effective date of this Part such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water</u>, shall use a storage vessel measurement system to determine the quantity <u>and quality</u> of liquids in the storage vessel(s). New tank batteries receiving an annual average of 200 bbls oil/day or more with available grid power shall be outfitted with a lease automated custody transfer (LACT) unit(s).

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels closed and latched during activities to determine the quantity of liquids in the storage vessel(s), ~~except as necessary for custody transfer.~~ Tank batteries equipped with LACT units shall use the LACT unit measurements in lieu of field testing of quantity and quality except in case of malfunction. Nothing in this paragraph shall be construed to prohibit the opening of thief hatches, pressure relief devices, or any other openings or access points to perform maintenance or similar activities designed to ensure the safety or proper operation of the storage vessel(s) or related equipment or processes. Where opening a thief hatch is necessary, owners and operators of new and existing storage vessels shall minimize the time the thief hatch is open.

<u>CEP:</u> The CEP propose adding subsection 20.2.50.123(C), based almost word-for-word on an amended to Regulation 7 adopted by the Colorado Air Quality Control Commission in December 2019. CAA Ex. 3 at 27 (citing 5 Colo. Code Regs. § 1001-9:D.II.C.4). The provision would require the use of storage vessel measurement systems for storage vessels at new and modified facilities. CEP Ex. 1 at 28. The proposal would reduce emissions by requiring operators to employ a measurement system that eliminates the need to open the thief hatch when conducting routine measurements of the quantity and quality of the liquid. CAA Ex. 3 at 27. Oxy supported this proposal and proposed it as well. 9 Tr. 2900:10-22. Oxy's expert, Mr. Holderman, testified that Oxy USA believes this addition is reasonable, workable, and likely to reduce emissions. 9 Tr. 2900:18-22.

NMED adopted this proposal in large part. However, two important differences render the Department's proposal less protective than the CEP and Oxy's proposal. First, the Department's proposal only requires use of a storage tank measurement system capable of measuring the **quantity** of liquid. The CEP propose a system that can also measure the **quality** of liquids. The evidence shows that a variety of alternative systems exist to measure quantity and sample the quality of the liquids in the vessel. See CAA Ex. 3 at 27 (examples of alternative systems that do not require venting include systems that comply with Chapter 18.2 of American Petroleum Institute Manual of Petroleum Measurement Standards, or by installing a Lease Automatic Custody Transfer unit). The evidence further shows that the Colorado proposal—which required a system to sample the quality of the liquid—is cost-effective. Id. Accordingly, substantial evidence supports the CEP's proposal to require a system capable of determining "the quantity and quality of liquids" in the storage vessel.

Second, the Department's proposal would allow operators to open a thief hatch "as necessary for custody transfer." This provision is ambiguous and could be used to circumvent the intent of the rule because a purchaser's desire to measure the quantity and quality of the liquid manually could be deemed sufficient reason to open the thief hatch even though it is not technically necessary to open the hatch. While there may be valid reasons to open a thief hatch (i.e., to conduct repairs), substantial evidence shows that routine measurement and sampling of liquid can and should occur without emissions.

Typically, operators open a thief hatch on the top of the tank to insert a gauging device to measure the level of liquid in the tank or to collect samples of the liquid. When the hatch is opened, air pollutants, including methane, VOCs, and cancer-causing hazardous air pollutants like benzene, are released. Since gauging is often performed frequently, and the hatch is opened every time a measurement is taken, these emissions can be significant. CAA Ex. 3 at 27. Operators can avoid these emissions by employing an alternative system to measure and sample the liquids in the vessel. Examples of alternative systems that do not require venting include systems that comply with Chapter 18.2 of American Petroleum Institute Manual of Petroleum Measurement Standards, or by installing a Lease Automatic Custody Transfer (LACT) unit. CAA Ex. 3 at 27.

In 2019, Colorado adopted a rule requiring operators to employ these types of alternative systems for new or modified storage vessels. Clean Air Advocates' proposal mirrors this provision. CAA Ex. 3 at 27. The Colorado Air Pollution Control Division ("APCD") analyzed the costs of its storage vessel measurement system. This analysis showed that use of a storage vessel measurement system is generally cost effective, with cost effectiveness increasing the more often measurement (which is carried out each time liquid is transferred from the tank to a truck, a process referred to as "loadout") occurs. APCD's analysis is below:

Loadout frequency	**Cost per ton VOC**	**TPY VOC reduced (per 8-tank battery)**
100 loads per year	$3,447/ton VOC	5.1
365 loads per year	$944/ton VOC	18.6

CAA Ex. 3 at 28.

The Colorado APCD found that these numbers were "extremely conservative" for several reasons, including the fact that "new and modified facilities that will be subject to these requirements will likely have production at such a level where loadout happens more often than even one time per day." CAA Ex. 3 at 28.

The CEP and Oxy's proposal has important safety benefits. The National Institute of Occupational Safety and Health and the Occupational Safety and Health

Administration issued a Hazard Alert in February 2016, explaining that the agencies had "identified health and safety risks to workers who manually gauge or sample fluids on production and flowback tanks from exposure to hydrocarbon gases and vapors, exposure to oxygen-deficient atmospheres, and the potential for fires and explosions." CAA Ex. 3 at 28. (citing NIOSH/OSHA Hazard Alert: Health and Safety Risks for Workers Involved in Manual Tank Gauging and Sampling at Oil and Gas Extraction Sites). The Hazard Alert explained that "[o]pening tank hatches, often referred to as 'thief hatches,' can result in the release of high concentrations of hydrocarbon gases and vapors" which "can have immediate health effects, including loss of consciousness and death." CAA Ex. 3 at 28. It went on to survey nine cases between 2010 and 2014 where a worker died while performing manual tank gauging. CAA Ex. 3 at 29. The Hazard Alert recommended use of "alternative tank gauging and sampling procedures that enable workers to monitor tank fluid levels and take samples without operating the tank hatch" to reduce occupational hazards associated with manual gauging. CAA Ex. 3 at 29. The CEP and Oxy's proposal would require exactly that at new and modified facilities, creating an important co-benefit in terms of occupational safety at the same time as it reduces emissions of ozone-forming VOCs and other dangerous pollutants. CAA Ex. 3 at 29.

Although the New Mexico Oil Conservation Commission (OCC) requires the use of auto-gauging technology at certain tanks, its rule is not as protective as the one set forth by the CEP and Oxy. 9 Tr. 3015:3–9. First, the OCC rule only requires technology that can measure the quantity of liquid, whereas the CEP and Oxy's proposal, like the Colorado rule, requires the use of technology that can automatically measure both the quantity and **quality** of liquids. 9 Tr. 3015:10–17. Second, the OCC rules does not expressly prohibit operators to open the thief hatch for gauging or sampling purposes, whereas the CEP and Oxy's proposal does. 9 Tr. 3015:10-17, -18–21.

Substantial evidence supports adopting the CEP proposal in full, and the EIB should adopt it. [See also CEP proposed SOR 196-213.]

<u>NMOGA proposes three edits in Section C(1):</u>

(1) The owner or operator shall keep thief hatches (or other access points to the vessel) and pressure relief devices on storage vessels <u>equipped with a storage vessel measurement system</u> closed and latched during activities to determine the quantity of liquids in the storage vessel(s), except as necessary for custody transfer. Tank batteries equipped with LACT units shall use the LACT unit measurements <u>and samples</u> in lieu of ~~field testing of~~ <u>opening the thief hatch to test</u> quantity and quality except in case of malfunction……

<u>NMOGA</u>: As written, the provision applied the prohibition on opening the thief hatch to storage vessels without a storage vessel measurement system. Alternatively, "new" could be added before storage vessel in line 29. NMOGA has proposed this language to use the storage vessel measurement system whenever available. Language was also added to clarify that the LACT unit does not give readouts on quality, but enables quality samples to be taken of the oil passing through the unit without opening the thief hatch. See Smitherman rebuttal testimony, NMOGA Exhibit 41:10:38 - 12:15. [NMOGA found a typographical error in C(5)(c), reference to paragraph (3) instead of (1), corrected above.]

D. Monitoring requirements: No later than January 1, 2023, the owner or operator of a storage vessel shall:

(1) on a monthly basis, monitor, calculate, or estimate, the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig) if the storage vessel is directly downstream of a separator. When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the storage vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) prior to any monitoring event, date and time stamp the event and

enter the monitoring data in accordance with the requirements of this Part;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements of 20.2.50.112 NMAC.

NMED: Subsection D of Section 20.2.50.123 sets forth the monitoring requirements for storage vessels. These include monitoring, calculating, or estimating total monthly liquid throughput and the upstream separator pressure; inspecting the vessel monthly to ensure compliance with Section 20.2.50.123, and date and time stamping the inspection; complying with the monitoring requirements in Section 20.2.50.115 if using a control device; and complying with the general monitoring requirements in Section 20.2.50.112. The Department is proposing additional language specifying a compliance timeline for the monitoring requirements, which the Department believes is reasonable. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48 and NMED Rebuttal Exhibit 1, pp. 95-96.

[NMOGA's earlier proposal to require the Department to review and approve requests for extensions to the deadlines in this Section are not part of its final proposal.] Including a provision for the Department to consider extensions opens the door to operators seeking unnecessary and unwarranted extensions to the reasonable compliance deadlines afforded in the rule. See NMED Rebuttal Exhibit 1, pp. 94, 96. [NMOGA's proposal to add a date to the beginning of Section D(1) has already been incorporated by NMED.]

E. Recordkeeping requirements: No later than January 1, 2023, the owner or operator of a storage vessel shall comply with the following requirements:

(1) Monthly, maintain a record for each storage vessel of the following:

(a) unique identification number and location (latitude and longitude);

(b) monitored, calculated, or estimated monthly liquid throughput;

(c) the upstream separator pressure, if a separator is present;

(d) the data and methodology used to calculate the actual emissions of VOC (tpy);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) Verify each record of liquid throughput by dated liquid level measurements, a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) Make a record of the inspections required in Subsections C and D of 20.2.50.123 NMAC, including:

(a) the date and time stamp, including GPS of the location, of the inspection;

(b) the person(s) conducting the inspection;

(c) a description of any problem observed during the inspection; and

(d) a description and date of any corrective action taken.

(4) Comply with the recordkeeping requirements in 20.2.50.115 NMAC if complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control device.

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

NMED: Subsection E of Section 20.2.50.123 sets forth the recordkeeping requirements for storage vessels. These include monthly liquid throughput calculations or estimates and the most recent date of measurement; upstream separator pressure; data and methodology used to calculate actual emissions of VOCs; the controlled and uncontrolled VOC emissions; and the type, make, model, and identification number of any control device. A record of liquid throughput must be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer. Owners and operators are required to maintain records of the inspections conducted in accordance with Section 20.2.50.123 and records required by Section 20.2.50.115 if using a control device to comply with the emission standards of this Section, and must comply with the general recordkeeping requirements of Section 20.2.50.112. The Department is also proposing additional language specifying a compliance timeline for the recordkeeping requirements, which the Department believes is reasonable. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 144-48, and NMED Rebuttal Exhibit 1, p. 96.

[NMOGA’s proposal to add a date to the beginning of Section D(1) has already been incorporated by NMED above.]

F. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) and (2) of Subsection B of 20.2.50.123 NMAC through use of a control

device shall comply with the reporting requirements in 20.2.50.115 NMAC.

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

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

NMED: An owner or operator must comply with the reporting requirements of Section 20.2.50.115 if using a control device, and must comply with the general reporting requirements in Section 20.2.50.112. The Board adopts this proposal for the reasons stated in NMED Exhibit 32, pp. 146-48.

Estimated Emissions Reductions and Costs of Section 20.2.50.123

ERG estimated the overall emission reductions from Section 20.2.50.123 to be 7,739 tpy of VOC for an overall reduction of 48%. ERG estimated that these reductions would be achieved at an overall cost effectiveness of $2,695 per ton of VOC. A detailed explanation of this analysis is provided in NMED Exhibit 32, pp. 147-48; NMED Exhibit 100 – Storage Tanks Reductions and Costs Spreadsheet; NMED Rebuttal Exhibit 28 – Updated Storage Tanks Reductions and Costs Spreadsheet; and NMED Rebuttal Exhibit 29 – NMED Single Tank Cost Estimate Spreadsheet. The Board should find that NMED's estimated costs associated with Section 20.2.50.116 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

20.2.50.124 WELL WORKOVERS

NMED: **Description of Equipment or Process**

Some wells require supplementary maintenance to maintain production or minimize the decline in production. These operations are referred to as workovers. Typical workovers include rod, tubing and casing repairs; siphon string or artificial lift installation paraffin removal; and pump repairs. Workovers are performed on wells that have previously been completed and have produced some reservoir fluids (water, oil, and/or natural gas). These wells have to be prepared before workover operations can begin. If the well is still producing and/or has pressure, the well will need to be blown down (i.e., vented) before it is safe to remove the tubing head and install the blowout preventers (BOPs). The well pressure can be decreased by venting to the atmosphere or by opening the casing to the sales line or the suction of a wellsite compressor.

In many cases, the fluids in the wellbore will build up to the point the well "dies" – this refers to the instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir pressure. In some cases, it will be necessary to pump water or other fluids into the wellbore to "kill" the well. As a safety precaution, after the BOPs are installed, the well is usually vented to atmosphere via a tank. Workovers are usually short duration projects that only last a few days or weeks at the most. After the well is prepared (i.e., blown down and BOPs installed), the workover operations can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a tank for the duration of the workover. Since these operations are typically performed during daylight hours, the well is shut in or returned to the sales line at the end of the day. NMED Exhibit 32, pp. 149-50.

Control Options for Well Workovers

Best management practices are the best means of reducing emissions during well workovers. These include reducing wellhead pressure before blowdown to minimize the volume of natural gas vented; monitoring manual venting at the well until the venting is complete; and routing natural gas to the sales line, whenever possible. NMED Exhibit 32, p. 150.

Rule Language

The proposed requirements for workover operations are based on requirements in Colorado Reg. 7 and Wyoming's Permitting Guidance, as detailed in NMED Exhibit 32, pp. 151-52.

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

NMED: Section 20.2.50.124 applies to workovers performed at oil and natural gas wells. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 149-152.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

NMED: Subsection B of Section 20.2.50.124 sets forth emission standards for well workovers. The owner or operator of an oil or natural gas well must use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering or operational practices: (1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented; (2) monitor manual venting at the well until the venting is complete; and (3) route natural gas to the sales line, if possible. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Exhibit 1, p. 97.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

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

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the estimated volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

NMED: Subsection C of 20.2.50.124 sets forth monitoring requirements for well workover operations. During a well workover, an owner or operator is required to monitor wellhead pressure, natural gas venting flow rate, and elapsed venting time in order to estimated volume and mass of VOC vented during a well workover. Owners and operators must comply with the general monitoring requirements in Section 20.2.50.112. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Ex. 1, p. 97.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:

(a) unique identification number and location (latitude and longitude) of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and 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) description of the best management practices used to minimize release of VOC emissions before and during the workover;

(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and gas composition; and

(h) the method of notification to the public and proof that notification was made to the affected public.

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

NMED: Subsection D of Section 20.2.50.124 sets forth recordkeeping requirements for well workovers. For each workover, the owner or operator must record the identification number and location of the well; date; wellhead pressure; flow rate or maximum potential flow rate; duration of venting; best management practices used; and the estimated VOC emissions released; and method of notification to the public and proof of notification as required in Subsection E of Section 20.2.50.124. Owners and operators must comply with the general recordkeeping requirements in Section 20.2.50.112. NMED made revisions to these provisions based on comments by NMOGA and IPANM as outlined in NMED Rebuttal Exhibit 1, p. 97. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 151-152, and NMED Rebuttal Exhibit 1, p. 97.

E. Reporting requirements:

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

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail, or by other effective means of notice so long as the notification can be documented, all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

(3) If the workover is needed for routine or emergency downhole maintenance to restore production lost due to upsets or equipment malfunction, the owner

or operator shall notify all residents located within one-quarter mile of the well of the planned workover at least 24 hours before the workover event.
[20.2.50.124 NMAC - N, XX/XX/2021]

NMED: Subsection E of 20.2.50.124 sets forth reporting requirements relating to well workovers. Owners and operators must comply with the general reporting requirements in Section 20.2.50.112. When venting cannot be avoided, the owner and operator must notify all residents located within one-quarter mile of the well at least three days before the workover by certified mail or other effective means of notice. NMED made revisions to these provisions based on comments by NMOGA, as outlined in NMED Rebuttal Exhibit 1, p. 97. Specifically, NMED added a new paragraph to this Subsection providing an exception to the 3-day notification requirement in Paragraph (1) for emergency or routine workovers due to upsets or equipment malfunctions, allowing notification of the public within 24 hours of the event. The Board should adopt the Department's proposal for the reasons stated in NMED Ex. 32, pp. 151-152, and NMED Rebuttal Ex. 1, p. 97.

IPANM proposes to remove the entire requirement to notify residents within ¼ mile of the well by certified mail within three calendar days of the workover event. The Department disagreed with this proposal. However, NMED did to modify this requirement to allow other notification options besides certified mail, so long as they can be documented. NMED recognized that there are other effective means to notify the public of these activities, and certified mail is not the only option to provide this notification. Possible alternatives include notices via text or email. The Board should reject IPANM's proposal for these reasons. NMED Rebuttal Exhibit 1, p. 97.

Estimated Costs and Emissions Reductions from Section 20.2.50.124

Emission estimates for workover operations are not currently available in the modeling emissions inventory or found in the NMED Equipment Data. Therefore, no estimate of emissions reductions is currently available. Section 20.2.50.124 specifies certain best management practices that must be used when conducting well workover operations, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the well during the workover operation, but no capital costs are anticipated. Costs associated with well workover best management practices are expected to be minimal as personnel will already be onsite conducting the well workover and any additional training may be incorporated into existing personnel training programs. NMED Exhibit 32, p. 152. The Board should find that NMED's estimated costs associated with Section 20.2.50.116 are reasonable and necessary to achieve the purpose of Section 74-2-5(C) of the AQCA.

<u>IPANM proposes to delete **E (2) and (3)** in their entirety:</u>

NMED's proposed 20.2.50.124 NMAC specifies requirements for workovers performed at oil and natural gas wells. A well workover is a supplementary maintenance activity that is required for some wells to maintain production or minimize production declines. "Typical workovers include rod, tubing and casing repairs; siphon string or artificial lift installation paraffin removal; and pump repairs." Workovers are performed on wells that have previously been completed. The wells need to be prepared before workover operations can begin. Preparation includes venting pressure before it is safe to remove tubing head and installing blowout preventers. A workover is usually a short duration project that lasts only a few days or weeks at most.

During the workover, the well is allowed to vent to the atmosphere to provide for the safety of the rig crew. NMED proposes to reduce emissions during a well workover through the implementation of best practices, including the following: reducing wellhead pressure before blowdown to minimize the volume of natural gas vented; monitoring manual venting at the well until the venting is complete; and routing natural gas to the sales line, if possible. As part of the best practices, NMED's proposal requires an operator to notify all residents within one-quarter mile of the well at least three days before the workover by certified mail. [See record citations in IPANM's SOR 239-256.] IPANM objected to this proposal on the grounds that the three-day advance notice requirement would unnecessarily delay well workers and result in more miles traveled by workover rigs to perform routine downhole maintenance. IPANM Ex. 2 at 18 (Davis Direct). IPANM testified that when a workover rig is working in an area and a well in close proximity "goes down, we may need to be able to move the rig to the location within 24 hours to avoid having the rig leave the area and return later." IPANM Ex. 2 at 18 (Davis Direct).

NMOGA also objected to the proposal on the grounds that it will have no effect on emissions. NMOGA requested an exemption for the three-day notice when routine well work that is not expected to generate significant emissions is being completed. NMOGA Appendix A1 at 30 (Smitherman Direct). NMOGA also proposed that the Department include more flexibility in the type of notice since there are many new methods to communicate that are easier and more transparent that using certified mail. NMOGA Appendix A2 at 31 (Smitherman Direct).

In NMED's rebuttal, the Department agreed to include more flexible means of communication, other than certified mail to notify local landowners. NMED also included an exception to the three-day notification requirement for emergency or routine workovers due to upsets and equipment malfunctions. For the exception, NMED shortened the notice time to 24-hours of the event.

IPANM's rebuttal reiterated its concerns with the three-day notice provisions and questioned how a notification to nearby residents actually results in any reduction in VOC emissions. IPANM Ex. 10 at 23 (Davis Rebuttal). At the hearing Ms. Bisbey-Kuehn explained the changes NMED had made to the rule that were outlined in her rebuttal testimony. Tr. Vol. 9, 3097:9-3104:23. Mr. Davis testified that most of IPANM's concerns with the rule have been addressed by NMED; however, it still had a concern about the administrative burden of the required notification for routine workovers. Tr. Vol. 9, 3107:25-13. Further, Mr. Davis testified that the quarter-mile distance could encompass a lot of residents for notification purposes and this would be a serious administrative burden in more densely populated areas. Tr. Vol. 9, 3108:14-3109:19.

IPANM suggested that NMED allow for alternate notification options such as erecting signs at the entrance of the well sites and creating a smaller buffer for notification to residents as some wells are in residential areas and this would require a significant amount of notice. Tr. Vol. 9, 3109:6-19 (Davis). The Board should find that the language as proposed in IPANM's September 16, 2021, version of the Ozone Rule for 20.2.50.124 should be adopted.

<u>NMOGA agrees that this section should be stricken:</u> According to NMED witness, Mr. Palmer, "emissions estimates for workover operations are not currently available in the

modeling emissions inventory or found in the NMED equipment data. Therefore, we do not have an estimate of emission reductions from well workovers." Tr. 9:3101:19-23. The workover proposal has no federal counterpart and is thus subject to the heightened substantial evidence standard in NMSA 1978, § 74-2-5.G. Because the record contains no evidence on the amount of VOCs reduced or whether such reductions have any impact on ozone, the Board finds that the record does not support adoption of the standard.

Oxy proposes to add a paragraph (4) to 124E:

(4) For the purpose of notifications pursuant to Paragraphs (2) and (3) of Subsection E of this 20.2.50.124 NMAC, residents shall include those individuals in manufactured, mobile, and modular homes, except that any such manufactured, mobile, or modular home intended for temporary occupancy or for business purposes should be excluded. The owner or operator shall calculate the one-quarter mile distance from residents based on the distance from the latitude and longitude of wellheads to 1) the property line for schools, 2) the property line for outdoor venues and recreation areas, 3) the location of buildings or structures used as a place of residency, and 4) the location of commercial buildings.

Oxy: Oxy USA supports the notification requirements in 20.2.50.124.E(2) NMAC. However, Oxy USA believes that 20.2.50.124 NMAC should be modified to be consistent with the use of "occupied areas" by the Department in 20.2.50.116 NMAC. Specifically, 20.2.50.124 NMAC should be clarified to state that the quarter mile distance covers the distance from the latitude and longitude of wellheads to: 1) the property line for schools; 2) the property line for outdoor venues and recreation areas; 3) the location of buildings or structures used as a place of residence; and 4) the location of commercial buildings. In addition, notification to "residents" should cover anyone in manufactured, mobile, and modular homes, except that any such manufactured, mobile, or modular home intended for temporary occupancy or for business purposes should be excluded. These clarifications will help ensure more accurate evaluations and rule consistency.

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to Sections 20.2.50.125 NMAC and 20.2.50.127 NMAC of this Part. Small business facilities are not subject to any other requirements of this Part unless specifically identified in 20.2.50.125 NMAC.

NMED: Section 20.2.50.125 applies to small business facilities as defined in Section 20.2.50.7. The Department is proposing additional language to clarify what sections of Part 50 apply to small business facilities. The Board should adopt this proposal for the reasons stated in NMED Ex. 102, pp. 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is 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 to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (9) of Subsection A of 20.2.50.112 NMAC if requested by the department.

NMED: Subsection B of Section 20.2.50.125 sets forth general requirements for small business facilities including operating equipment in accordance with manufacturer specifications and keeping those specifications on file; calculating the annual VOC and NOx emissions from each facility using the actual production and processing rates; maintaining a company-wide database of emission calculations for all subject facilities; and complying with third party verification requirements if requested by the Department. No party specifically commented on Subsection B or provided suggested revisions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15 and NMED Rebuttal Exhibit 1, pp. 97-99.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC. The owner or operator shall comply with Subsection B of 20.2.50.111 NMAC in determining applicability of the requirements in 20.2.50.116 NMAC.

NMED: Subsection C of Section 20.2.50.125 requires owners and operators of small business facilities comply with the fugitive leak monitoring requirements in Subsections C and D of Section 20.2.50.116. No party specifically commented on Subsection C or provided suggested revisions. The Department is proposing to add a reference to the PTE calculation requirements in Section 20.2.50.111 to clarify applicability of those provisions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15. and NMED Rebuttal Exhibit 1, pp. 97-99.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

NMED: Subsection D of Section 20.2.50.125 requires owners or operators of small business facilities to repair equipment leaks as specified in Subsection E of Section 20.2.50.116. No party specifically commented on Subsection D or provided suggested revisions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, and NMED Rebuttal Exhibit 1, pp. 97-99.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated annual VOC and NO_x emissions from each facility and the company-wide annual VOC and NO_x emissions for all subject facilities; and

(3) records as required under Subsection F of 20.2.50.116 NMAC.

NMED: Subsection E of Section 20.2.50.125 sets forth recordkeeping requirements for owners of small business facilities, including completing an initial certification certifying that the small business facility meets the definition of small business facility in Part 50, and annual certifications thereafter; and calculating annual VOC and NOx facility emissions and the company-wide emissions for all subject facilities. No party specifically commented on Subsection E or provided suggested revisions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, pp 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 of each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

NMED: Subsection F of Section 20.2.50.125 requires owners and operators to submit a certification that they meet the definition of small business facility within the specified time frames. Owners and operators must also comply with the general reporting requirements in Section 20.2.50.112. No party specifically commented on Subsection F or provided suggested revisions. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, pp. 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.
[20.2.50.125 NMAC - N, XX/XX/2021]

NMED: Subsection G of Section 20.2.50.125 contains an important provision that triggers the applicability of the remaining sections and requirements of Part 50 if the Secretary of the Department finds, based on credible evidence, that the facility presents an imminent threat to public health or welfare or to the environment; is not being operated in a manner that minimizes emissions of air contaminants; or has violated another requirement of Section 20.2.50.125 NMAC. This provision incentivizes owners and operators of small business facilities to fully comply with Section 20.2.50.125 providing for an applicability onramp for the other sections of Part 50 if they fail to do so. The annual emissions data collected and reported to the Department will be used in air quality planning projects, air dispersion modeling analyses, air emissions databases and emissions inventories, and in other air quality related projects. The Board should adopt this proposal for the reasons stated in NMED Exhibit 102, p 13-15, and NMED Rebuttal Exhibit 1, pp. 97-99.

IPANM: proposes to delete section 125.G in its entirety:
See also IPANM's arguments under **20.2.5.50.7.OO NMAC Small Business Facilities**

IPANM: NMED's proposed 20.2.50.125(G) NMAC states that a source that meets the definition of a small business facility can be required to comply with the other sections of

20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.12 The Department explained that proposed 20.2.50.125(G) incentivizes owners and operators of small business facilities to comply with 20.2.50.125 providing for an applicability onramp for the other sections of Part 50 if they fail to do so. NMED Ex. 102 at 15 (Day/Kuehn). The record, however, contains no support as to how proposed 20.2.50.125(G) NMAC provides an applicability on-ramp for owners and operators subject to the Ozone Rule. *See* Tr. Vol. 4 *in passim*. IPANM recommends that proposed 20.2.50.125(G) not be adopted for lack of record support.

The Department's enforcement authority is independent of the Board's authority and derives directly from the Legislature. *See* NMSA 1978 § 74-2-12(A)(1) and (2). The Legislature has not delegated authority to the Board that allows it to confer enforcement authority unto the Department. *See* NMSA 1978 § 74-2-5(A)-(G). The Board, consequently, does not have the requisite authority to confer enforcement authority unto the Department as provided in Section 125(G) because it is inconsistent with the Air Act and the duties and powers of the Board. *See* § 74-2-12(A)(1) and (2); § 74-2-5(A)-(G). The Board, therefore, does not have authority to promulgate proposed Section 125(G). *See Wilcox v. New Mexico Bd. of Acupuncture & Oriental Med*., 2012-NMCA-106, ¶ 7. The Board should find that the language as proposed in the September 16, 2021, version of the Ozone Rule for 20.2.50.7.OO and 20.2.50.125(G) is not appropriate because gross annual revenue is not a measure of the business's profitability, and the proposed 20.2.50.125(G) lacks record support and is beyond the Board's rulemaking authority to confer enforcement authority to NMED. Based on the evidence presented, the Board should find IPANM's proposed version of 20.2.50.7VV and 20.2.50.125 NMAC is appropriate and should be adopted. The fifty-employee cutoff provides the necessary relief for small business in New Mexico.

Under Section 74-2-12, civil enforcement authority is delegated to the Secretary of the Department. The Secretary may issue a compliance order or commence a civil action in district court upon a determination that a person has violated or is violating the

Air Act or a regulation promulgated pursuant thereto, and "may include a suspension or revocation of the permit or portion thereof issued by the secretary . . . that is alleged to have been violated." See NMSA 1978 § 74-2-12(A)(1) and (2) and (B).

The EIB's jurisdiction is statutorily defined and it is limited to the exercising the authority granted by statute. See *New Mexico Taxation & Revenue Dep't, 2019-NMCA-054*, ¶ *6; Wilcox*, 2012-NMCA-106, ¶ 7 ("An administrative agency has no power to create a rule or regulation that is not in harmony with its statutory authority."). The Department's enforcement authority is independent of the Board's authority and derives directly from the Legislature. The EIB, consequently, does not have the authority to grant additional enforcement authority to the Department. In effect, the Board usurps the role of the Legislature by promulgating Section 125(G). Because the Board has no authority to promulgate this rule, it must reject proposed Section 125(G).

NMOGA: NMOGA supports the position of IPANM on the appropriate contours of the Small Business Facilities provision.

See above, in the definition of "small business facility," for related argument from other parties.

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

NMED: **Description of Equipment or Process**

The majority of oil- and gas-bearing formations also contain naturally occurring water, often referred to as "formation" or "connate" water. When oil or gas is extracted, this "produced water" is also extracted as a by-product. The actual amount of produced water varies widely depending on factors such as location or stage in the lifetime of a particular well. In addition to reflecting the chemical makeup of the geologic formation from which it is extracted, produced water will also contain suspended solids, dissolved solids, varying amounts of oil residues and organics containing VOCs, and the various chemicals used in the production process. Produced water from gas production typically has higher contents of low molecular-weight aromatic hydrocarbons, such as benzene, toluene, ethylbenzene, and xylene (BTEX) than produced water from oil production. NMED Exhibit 32, p. 153.

Conventional Oil and Gas

On average, about 7 to 10 barrels, or 280 to 400 gallons, of water are produced for every barrel of crude oil. Oil reservoirs commonly contain larger volumes of water than gas reservoirs because gas is stored and produced from less porous reservoirs that contain source rock with a lower water capacity. Produced water generation commonly increases over time in conventional reservoirs as the oil and gas is depleted during hydrocarbon production. *Id.* at 153-54.

Unconventional Oil and Gas

Produced water from most unconventional resources, besides coal bed methane, is minimal due to tighter reservoir formations such as tight sands, oil shale, and gas shale reservoirs. Producers commonly import water to these operations for onsite use in drilling, fracturing, and production. Fresh water used in drilling applications for fracturing is contaminated by the saline water in the reservoir. Fresh water brought onsite for use in operations, such as flow back or water returning from fracturing applications ("frac water"), also is managed as a waste stream. This waste stream is commonly associated with the initial phase of well development and production. In most unconventional oil and gas operations, frac water is considered the largest waste stream of production. *Id.* at 154.

Control Options

VOC emissions from PWMU can be reduced by treating the produced water to remove hydrocarbons before the water enters the recycling facility or impoundment. The emissions are reduced when produced water is processed through three-phase separators and storage vessels, which separates the hydrocarbons from the produced water prior to sending to a PWMU. NMED Exhibit 32, p. 154.

A. Applicability: Produced water management units as defined in this Part and their associated storage vessels are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

NMED: Section 20.2.50.126 applies to produced water management units (PWMU) as defined in Part 50. PWMUs and their associated storage vessels must comply with the requirements in Section 20.2.50.126 no later than 180 days after the effective date of Part 50. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 153-56, and NMED Rebuttal Exhibit 1, pp. 99-100.

[CDG's earlier proposed revisions regarding air permits and OCD permits in this section are not part of its final proposal.] The Board's air permitting regulations already require owners and operators to submit Notice of Intent (NOI) registrations or air permit applications if the emissions exceed applicability thresholds and, thus, the proposed requirement is redundant with other existing regulatory requirements. NMED disagrees that Part 50 should not apply to a permitted PWMU; Part 50 is intended to apply to all subject sources, regardless of permitting status. NMED Rebuttal Exhibit 1, p. 100. OCD's regulatory authority is based on preventing waste of a resource under the Oil and Gas Act; it does not regulate emissions of air pollutants for purposes of meeting national ambient air quality standards. OCD's requirements are not equivalent to the requirements of Part 50, and do not require reductions of VOC emissions using best management practices. There is no basis for exempting facilities from compliance with Part 50 on the basis that they are permitted or registered with OCD under a different set of regulations and statutory authority. See NMED Rebuttal Exhibit 1A, p. 2.

B. Emission standards:

(1) The owner or operator shall use good operational or engineering practices to minimize emissions of VOC from produced water management units (PWMU) and their associated storage vessels.

(2) The owner or operator shall not allow any transfer of untreated produced water to a PWMU without first processing and treating the produced water in a separator and/or storage vessel to minimize entrained hydrocarbons.

(3) Within two years of the effective date of this Part for storage vessels associated with existing PWMUs, or upon startup for storage vessels associated with new PWMUs, the owner or operator shall either:

(a) control such storage vessels in accordance with the requirements of Section 20.2.50.123 NMAC that are applicable to tank batteries; or

(b) submit a VOC minimization plan to the department demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The plan shall state the good operational or engineering practices used to minimize VOC emissions. The plan shall be enforceable by the department upon submission. The department may require revisions to the plan, and must approve any proposed revisions to the plan.

NMED: Subsection B of Section 20.2.50.126 sets forth emission standards for PWMUs. Paragraph (1) requires owners and operators to employ best management and good engineering practices to minimize emissions of VOC from produced water management units. Paragraph (2) prohibiting owners from transferring untreated produced water to a PWMU without first processing and treating it to remove entrained hydrocarbons. NMED made significant revisions to this Subsection based on comments from NMOGA and CDG, as detailed in NMED Rebuttal Exhibit 1, p. 100. The Board should adopt the Department's proposal for the reasons stated in NMED Exhibit 32, p. 154-56, and NMED Rebuttal Exhibit 1, p. 100.

The Department is also proposing a new Paragraph (3) of this Subsection addressing storage vessels associated with PWMUs. Owners and operators are required to either control such storage vessels in accordance with the requirements of Section 20.2.50.123 that are applicable to tank batteries, or submit a VOC minimization plan to the Department demonstrating that controlling VOC emissions in accordance with Section 20.2.50.123 is technically infeasible, and identifying good operational or engineering practices that will be used to minimize VOC emissions. These changes were addressed at the hearing. *See* Tr. Vol. 9, 3177:14-18, 3178:7-16. The Board should adopt this proposal for the reasons stated at the hearing.

CDG: CDG supports the addition of a provision regarding technical infeasibility without supplemental fuel, see CDG NOI Direct Testimony - Il Kim, pgs. 3-4, CDG Attachment D - Streams with High Moisture Content, CDG Attachment E - Cost Estimate of the Economic Impacts, and Hearing Transcript - Il Kim, Volume 9, pg. 2935, line 20 through pg. 2936, line 16. Acceptance of concept by NMED: Transcript -Elizabeth Bisbey-Kuehn, Volume 9, pg. 3033, line 12 through pg. 3034, line 6.]

CDG provides services for disposal of produced water at underground injection well facilities and recycling of produced water at produced water management unit (PWMU) facilities. Millions of barrels of produced water are recycled each year at PWMUs and returned to oil and gas producers for use in hydraulic fracturing and other reuse operations in lieu of using fresh water. These recycle ponds are several acres in size and often have the capacity to contain several hundred thousand barrels of water. A common and successful approach to minimizing emissions from PWMUs is to implement good operational and engineering practices through the reduction of hydrocarbons in the water prior to entering the pond. The water sent to these PWMUs goes through good operational and engineering practices to reduce emissions.

NMED's Proposed Rule recognizes these distinctions and is drafted to achieve the legislative purpose to protect and enhance the environment and water conservation while enabling Group members to responsibly conduct their businesses in compliance with the Rule's provisions. The goal of reducing ozone emissions is achieved, while preserving the continued utilization of produced water recycling, reuse, and treatment operations so important to New Mexico's efforts to safeguard its valuable water resources. The Proposed Rule encourages further responsible investment in and operation of critical water recycling, reuse, and treatment operations in New Mexico. [CDG NOI Direct Testimony: Il Kim, pgs. 3-4; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.].

Generally, the produced water received by the Group has been processed by the producers prior to its receipt and is then typically further processed by the members of the Group. This water is therefore considered "post-flash" water that characteristically contains very low levels of VOCs. In some situations, emission reductions are technically infeasible without the use of supplemental fuel for combustion of vapors. In these situations, sites with very low hydrocarbon concentrations in the vapors could end up increasing total emissions of not only VOCs, but NOx and carbon monoxide as well, due to the use of supplemental fuel for combustion. To avoid these unintended and harmful results, the Proposed Rule provides a process for a PWMU operator to submit a VOC minimization plan to NMED demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel.

This option assures that the Rules' requirements, which apply to the commercial produced water recycling and disposal industry, are technically feasible and cost effective with commensurate environmental benefit. [CDG NOI Direct Testimony: Il Kim, pgs. 3-4, 8; Jill Cooper, pgs. 4-6; Ashley Campsie, pgs. 5-6; Exhibit CDG 4 - Streams with High Moisture Content; Exhibit CDG 5 - Cost Estimate of the Economic Impacts; Hearing Transcript, Volume 9, 2935:20 – 2936:16; 3033:12 – 3034:6.]

<u>NMOGA supports paragraph (3) if recycling facilities are not excluded from PWMU:</u>

The Department's initial proposal for 20.2.50.126 NMAC received significant feedback as technical testimony demonstrated issues with proposed emissions limits and their potential impact on water recycling activities. The Board should find it is in the best interest of New Mexico to not hinder water recycling and reuse. The Department's most recent proposal responds to these concerns by imposing requirements that are achievable with current technology and largely preserve owners' and operators' ability to continue recycling activities.

Industry stakeholders have urged the Board to further protect the industry's recycling activities by excluding "recycling facility" from the definition of produced water management units. Campsie, CDG Exhibit B, 8:9-15; Campsie, CDG Reb. Ex. B, 4:7-16; Cooper, CDG Reb. Ex. E, 7:11-18. It is particularly important to clearly exclude recycling facilities that are not at frac ponds or pits, often called Recycle on the Fly (ROTF) units, a collection of temporary tanks that move around to accommodate frac schedules. These facilities do not have pits or ponds. The water held in these tanks have already been through separation, and imposing section 20.2.50.126 NMAC—which requires separation—on these units will not meaningfully reduce emissions. Any further control would require supplemental fuel and a temporary flare. The Board should find this change is warranted to further preserve the industry's ability to recycle water.

Industry stakeholders also provided extensive testimony that supplemental fuel may be needed to control storage vessels associated with produced water management units. See, e.g., Kim testimony, Tr. 7:2290:6-13. Technical testimony also shows that this may not be technically feasible and may not provide a net environmental benefit. Kim testimony, Tr. 7:2290:6-13. To address this and related concerns, the Department has proposed that, within two years of the effective date for an existing tank associated with PWMUs or upon startup of a new storage vessel associated with PWMUs, owners and operators must either control the storage vessel in accordance with the requirements of Section 20.2.50.123 or submit a VOC minimization plan to the Department demonstrating that controlling VOC emissions from storage vessels associated with the PWMU in accordance with the requirements of Section 20.2.50.123 NMAC is technically infeasible without supplemental fuel. The Board should find this proposal is supported by substantial evidence and the weight of the evidentiary record.

C. Monitoring requirements: The owner or operator shall:

(1) develop a protocol to calculate the VOC emissions from each PWMU. The protocol shall include at a minimum: produced water throughput monitoring, semi-annual sampling and analysis of the liquid composition, hydrocarbon measurement method(s), representative sample size, and chain of custody requirements.

(2) calculate the monthly total VOC emissions in tons from each unit with the first month of emission calculations beginning within 180 days of the effective date of this Part;

(3) monthly, monitor the best management and good operational or engineering practices implemented to reduce emissions at each unit to ensure and demonstrate their effectiveness;

(4) upon written request by the department, sample the PWMU to determine the VOC content of the liquid; and

(5) comply with the monitoring requirements of 20.2.50.112 NMAC.

NMED: Subsection C of Section 20.2.50.126 sets forth monitoring requirements for PWMUs. Paragraph (1) requires owners and operators to develop a protocol to calculate VOCs from each PWMU and specifies minimum requirements for such protocols. Paragraph (2) requires calculation of monthly total VOC emissions from each unit beginning within 180 days of the effective date of Part 50. Paragraph (3) requires monthly monitoring of best management and operational practices used to reduce emissions at each unit, and demonstration of their effectiveness. Paragraph (4) allows the department to require an owner or operator to sample a PWMU to determine the VOC content of the liquid. NMED made numerous revisions to its original proposal in this Subsection based on comments from CDG and NMOGA, as detailed in NMED Rebuttal Exhibit 1, pp. 100-102. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 154-56; NMED Rebuttal Exhibit 1, pp. 100-102.

[CDG's earlier proposed revisions regarding BMPs have been addressed and are not part of its final proposal.] BMPs are used to prevent or reduce emissions from being emitted into the air, which is consistent with the intent of this requirement. It is appropriate for an owner or operator to track those BMPs with respect to their effectiveness in reducing emissions. Under the requirements of this Section, the owner or operator must periodically monitor the BMPs, in this case monthly, to ensure that they are effectively reducing emissions. Without monitoring the effectiveness of the BMPs, there is no way for the operator to determine if the BMPs are actually reducing emissions. NMED Rebuttal Exhibit 1, pp. 101-102.

CDG proposes to insert the word **"sample"** in front of the words **"chain of custody requirements"** as a clarification in C(1).

NMOGA: NMOGA supports CDG's proposed edit to Section C(1): insert the word "sample" in front of the words "chain of custody requirements" for clarification.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each PWMU:

(a) unique identification number and UTM coordinates of the PWMU;

(b) the good operational or engineering practices used to minimize emissions of VOC from the PWMU;

(c) the VOC emissions calculation protocol required in Subsection C of 20.2.50.126 NMAC, including the results of the sampling conducted in accordance with the protocol; and

(d) the annual total VOC emissions from each PWMU.

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

NMED: Subsection D of Section 20.2.50.126 specifies recordkeeping requirements for PWMUs. Owners and operators are required to maintain records for each produced water unit including its name or identification number; UTM coordinates; description of good operational and engineering practices used to minimize VOC releases; records relating to the monitoring protocol in Subsection C, including results of sampling conducted in accordance with the protocol and a record of the annual total VOC emissions. NMED made revisions to its original proposal in this Subsection based on comments from CDG, as detailed in NMED Rebuttal Ex. 1, p. 102. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 154-56; NMED Rebuttal Exhibit 1, pp. 100-102. [CDG's earlier proposed revisions in this section are not part of its final proposal.] NMED did agree to remove the monthly rolling 12-month total VOC emissions and replace it with an annual total VOC emission calculation. The rule already establishes a recordkeeping requirement of the BMPs used to comply with this Section. Both the record of the BMPs and the record of the VOC emission calculation are needed to demonstrate compliance with the requirements to minimize emissions of VOCs. NMED Rebuttal Exhibit 1, p. 102.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.126 NMAC - N, XX/XX/2021]

<u>NMED:</u>

Estimated Costs and Emissions Reductions from Section 20.2.50.126

Section 20.2.50.126 specifies that best management practices and good engineering practices must be used to minimize VOC emissions at PWMUs, but does not require the use of emission control devices. It is expected that these practices will require personnel to manage the minimization of emissions PWMUs, but no capital costs are anticipated. Costs associated with best management and good engineering practices are expected to be minimal as personnel will already be onsite at the facility, and any additional training may be incorporated into existing personnel training programs. PWMUs are unregulated under the federal Clean Air Act and its implementing regulations, and EPA has not published emission factors specific to this type of operation. NMED Ex. 32, pp. 155-56. The Board should find that the costs associated with Section 20.2.50.126 are reasonable, and the requirements of Section 20.2.50.126 help achieve important emissions reductions while continuing to encourage the use of produced water instead of freshwater resources throughout the industry.

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE EVIDENCE

A. Failure to comply with the emissions standards, monitoring, 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 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part that evidence or information may be used by the department for purposes of establishing whether a person has violated or is in violation of this Part.

NMED: Section 20.2.50.127 contains provisions regarding enforcement for violations of Part 50. Subsection A expressly states what is implicit in any mandatory requirement of an air quality regulation under the CAA or the AQCA: that failure to comply with any of the requirements in Part 50 within the specified timeframes constitutes a violation of Part 50 that is subject to enforcement action under the AQCA. This Section provides clear notice to the regulated community that failure to comply with the provisions of Part 50 will be subject to enforcement. Subsection B provides that the Department may use credible evidence or information obtained by the Department or provided to the Department by a third party to establish a violation under Part 50.

The Department worked with NMOGA, Oxy USA, Clean Air Advocates, and EDF to come up with the current proposed language for Section 20.2.50.127, and all the Parties stipulated to this language. The Board should adopt this proposal for the reasons stated in NMED Exhibit 32, pp. 157-58 and NMED Rebuttal Exhibit 1, p. 103. NMOGA urges the Board to adopt the language as stipulated.

NMOGA supports the stipulation: The parties reached a stipulation regarding the credible evidence provisions in 20.2.50.127 NMAC. The Board should find that prior language that presumed the liability of regulated entities and placed the burden of disproving third-party allegations on owners and operators was unreasonable, inconsistent with the Department's obligation to perform its own investigations, and incompatible with principles of due process. Bisbey-Kuehn Testimony, Tr. 6:1979:23-25 – 1982:1:20. The Board should find that the stipulated language adequately addresses these deficiencies and preserves the Department's ability to enforce Part 50.

New Proposed Section 127--Oxy USA and eNGO Joint Proposal for Flowback Vessels and Preproduction Operations

NMED: As part of their direct testimony, the eNGOs submitted a joint proposal to move the Department's proposed language in Section 20.2.50.127 to a new Section 20.2.50.128, and include new substantive requirements for flowback vessels and preproduction operations in Section 20.2.50.127, as well as additional definitions in Section 20.2.50.7 NMAC for the terms "Drilling" or "drilled"; "Drill-out"; "Flowback"; "Flowback vessel"; "Hydraulic fracturing"; "Hydraulic refracturing"; and "Pre-production operations". *See* eNGO Joint Proposed Amendments – July 28, 2021. As part of the rebuttal testimony submissions, Oxy USA and the eNGOs came together with a joint proposal on this new Section 20.2.50.127, including the associated definitions listed above. *See* eNGO and Oxy USA Joint Proposed Amendments – September 7, 2021. The Department did not take a position on this proposal; the Board should decide the issue based on the testimony of the other parties. Tr. Vol. 10, 3380:24 – 3381:9.

20.2.50.127 REQUIREMENTS FOR FLOWBACK VESSELS AND PREPRODUCTION OPERATIONS

A. Applicability: Wells undergoing recompletions and new wells being completed at an existing wellhead site are subject to the requirements of 20.2.50.127 NMAC one year after the effective date of this Part. New wells constructed at a new wellhead site that commence completion or recompletion after the effective date of this Part are subject to the requirements of 20.2.50.127 NMAC.

B. Emissions standards:

(1) the owner or operator of a well that begins flowback on or after the effective date of this Part must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

(a) the owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(b) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is in compliance with 20.2.50.127.B(1)(a) NMAC prior to receiving flowback.

(c) the owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(i) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

(ii) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system or to add biocides or chemicals is not a violation of 20.2.50.115.H(1)(a)(i) NMAC.

C. Monitoring

(1) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including

(a) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

(b) visual inspection or monitoring of the control device to ensure that it is operating.

(c) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

D. Recordkeeping

(1) The owner or operator of each flowback vessel subject to Paragraph (1) of Subsection B of Section 20.2.50.127 NMAC must maintain records for a period of five (5) years and make them available to the NMED upon request, including

(a) the API number of the well and the associated facility location, including latitude and longitude coordinates.

(b) the date and time of the onset of flowback.

(c) the date and time the flowback vessels were permanently disconnected, if applicable.

(d) the date and duration of any period where the control device is not operating.

(e) records of the inspections required in Paragraph (2) of Subsection B of Section 20.2.50.127 NMAC, including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

CEP: The CEP and Oxy support the completions/recompletions proposal above. NMED took no position, citing lack of expertise, and recommended the EIB decide the issue based on testimony of other parties. 10 Tr. 3380:24-3381:9.

The completions/recompletions proposal requires operators to route initial flowback to enclosed, controlled flowback vessels during completion and recompletion of wells to reduce emissions during initial flowback. This would reduce emissions during completions and recompletions of wells by requiring operators to route initial flowback to enclosed, controlled flowback vessels during completion and recompletion of wells. See CEP Ex. 1 at 35-36. The CEP and Oxy's proposed, at 20.2.50.127 NMAC, is modeled after rules adopted in 2020 by the Colorado Air Quality Control Commission and the Colorado Oil and Gas Conservation Commission (COGCC") with one significant change. The CEP and Oxy's completions/recompletions proposal deletes Colorado language requiring flowback vessels to be "vapor tight." This change was made to ensure that operators install a pressure relief system to prevent dangerous static buildup and discharge. 10 Tr. 3232:16-3233:5 [Alexander Test.]; 10 Tr. 3307:1-6 [Holderman Test.].

Implementation of the proposal is safe: EDF witness Tom Alexander and Oxy witness Danny Holderman testified in support of this proposal. Both Mr. Alexander and Mr. Holderman, an engineer, have expertise in completions; both managed completions for major oil and gas companies. Flowback tanks are used during oil and gas pre-production activities and can lead to uncontrolled VOC and methane emissions if the tanks are not designed to contain these vapors. EDF Ex. EE at 23 [CDPHE Cost-Benefit Analysis for Regulation 7]. The VOC and methane emissions from completions/ recompletions are not insignificant. See EDF Ex. EE at 26-27, Tables 12 & 13.

Mr. Alexander explained to the EIB how, under the proposal, emissions from "initial flowback" would be routed to flowback vessels. He explained how the flowback vessels have a pressure relief system to accommodate any safety issues that could arise from significant changes in pressure or flow rates. Any emissions from a pressure relief system must be routed to a flare equipped with an auto-ignitor or continuous pilot light to minimize venting and emissions during completions/recompletions. EDF Ex. UU at 12.

Both Mr. Alexander, who was Vice President of Health, Safety and Environment at a major oil and gas company, and Mr. Holderman testified that implementation of the proposal is safe. Indeed, operators in Colorado have not raised any concerns with implementing the completions/recompletions requirements with CDPHE.

NMOGA's only objection that the proposal is unsafe is based on a mischaracterization of the terms of the proposal. NMOGA's only real objection to the completions/recompletions proposal came from Mr. Smitherman who mischaracterized the proposal as requiring "vapor tight" vessels. Mr. Smitherman incorrectly characterized the proposal even though he admitted during cross-examination that he was aware that the "vapor tight" language had been removed because of safety concerns. 10 Tr. 3352:9-18. Mr. Smitherman's concern had to do with the "static buildup" that could occur during initial flowback with a "vapor tight" vessel. 10 Tr. 3322:3-14. However, as Mr. Holderman explained: "First, Oxy USA removed the vapor tight reference [from EDF and Clean Air Advocates' original proposal] because it could be read to exclude pressure relief systems which are an essential safety feature for control systems. The general control language Oxy USA has proposed would not restrict pressure relief systems and is more consistent with safe operation." 10 Tr. 3307:1-6.

Mr. Smitherman provided no testimony why the Community and Environmental Parties and Oxy's proposal, removing the vapor tight language, is problematic from a safety standpoint. Therefore, there is no evidence in the record why implementation of the completions/recompletions proposal would be unsafe. There's more than substantial evidence in the record from Mr. Holderman, an engineer with specialized knowledge of completions, and Mr. Alexander, a former safety director with specialized knowledge of completions, the requirements for reducing emissions from completions and recompletions from the proposal are safe. Moreover, both Colorado's air pollution agency and its oil and gas agency have adopted similar rules, after hearing, and the CDPHE report no operator complaints or issues with the requirements.

There is substantial evidence in the record that the completions/recompletions proposal is cost effective, and no evidence in the record to the contrary. Based on CDPHE's September 2020 detailed cost-benefit analysis for its flowback vessel rule, EDF environmental engineer Hillary Hull calculated the cost for the Community and Environmental Parties and Oxy's completions/recompletions proposal would be $259.48 per ton of VOC reduced, which is cost effective according to Ms. Hull. EDF Ex. SS at 15; EDF Ex. UU at 14; 10 Tr. 3283:1-10. When Mr. Alexander was a Completions Manager, his company was completing 400 to 500 horizontal wells a year. According to Mr. Alexander "we understood the costs" of completions and, in his expert opinion, the CEP and Oxy's completions/recompletions proposal is cost effective and the costs "are very, very reasonable." 10 Tr. 3229:6-3230:17; EDF Ex. UU at 13-14. No industry party presented a cost-benefit analysis for the Community and Environmental Parties and Oxy's completions/recompletions proposal or rebutted EDF's cost-benefit calculations.

The completions/recompletions proposal fills a regulatory gap. Neither the U.S. Environmental Protection Agency nor the New Mexico Oil Conservation Commission requires flowback to be routed to enclosed, controlled flowback vessels during initial flowback. 10 Tr. 3233:7-3234:6; -3234:13-21. The CEP and Oxy's completions/ recompletions proposal fills "a gap" in those rules, will reduce VOC and methane emissions during the initial flowback stage, and will strengthen the EIB's final rule. 10 Tr. 3234:3-6.

Uncontrolled emissions during completions and recompletions have real life impacts on persons living in close proximity to oil and gas development. Don Schreiber has lived in close proximity to oil and gas development for over two decades. There are about 122 gas wells on or around his ranch, including 33 wells within one mile of his home. He has firsthand experience with the impacts of oil and gas development and with the impacts of completions and recompletions of wells, which are a particular concern for him. CAA Ex. 10 at 2-3 [Schreiber Dir. Test.]. In the early 2000's, well completions were still being done essentially the same way as they had been for over 50 years in the San Juan Basin. CAA Ex. 10 at 2-3. The environmental impacts of blewie line completions were obvious to Mr. Schreiber and his family -- given all the audio, visual and olfactory evidence -- as they lived and worked around their ranch. The impacts came into especially sharp focus when one time as the flared gasses cooled, black "snowflakes" were created and drifted onto their home from a completion about 1¼ miles northeast of his ranch. CAA Ex. 10 at 2-3.

Moving away from outdated completions technology in order to avoid the harmful and toxic waste they created became a priority for Mr. Schreiber as ConocoPhillips planned to drill 44 wells in and around his ranch in 2008. At that time, Mr. Schreiber learned about "reduced emissions completions" or "RECs" that were already being done in the San Juan Basin and could help prevent the harmful emissions that he and his wife worried about. CAA Ex. 10 at 2-3. Mr. Schreiber worked with ConocoPhillips and BLM to develop a program for drilling the 44 wells that would reduce impacts to the land, water, and air. In September 2008, they reached agreement on the use of REC equipment, closed loop systems, well spacing, road construction, reclamation of surface damage, and other considerations that allowed the 44 well drilling program to begin in late 2008. Between 2008 and 2012, 22 of the 44 wells in the program were completed or recompleted consistent with his agreement with ConocoPhillips. In 2012, natural gas prices declined and the drilling program stopped. *Id.* at 6.

In August of 2017, Hilcorp Energy Company (Hilcorp) acquired ConocoPhillips' assets in the San Juan Basin, including all of the wells on and around the Schreibers' ranch. Since acquiring those assets, Hilcorp has refused to honor the agreement the Schreibers had with ConocoPhillips. Mr. Schreiber has witnessed Hilcorp completion operations in which flowback gasses are vented directly to the atmosphere, into the space where they live and work. CAA Ex. 10 at 7-8; CAA Ex. 18 [photographs of the Hilcorp operation with no REC equipment]. Mr. Schreiber strongly supports the CEP and Oxy's completions/ recompletions proposal. According to him:

> "There is now a gaping hole in New Mexico regulations that creates a serious issue that has plagued my family and other families who live, work, and go to school close to where oil and gas wells exist or may be drilled in the future. Standing on my ranch, I can see Colorado, less than 25 miles away. To know that the same operators that are allowed to vent ozone precursors, methane, and toxic pollutants from completions and recompletions in New Mexico are prohibited from doing so in Colorado is deeply troubling. These operators drill into the same formation. They vent pollutants into the same air shed. And they threaten communities in the same region of the country. If, unlike Colorado, New Mexico fails to adopt reduced emissions completion/recompletion requirements -- requirements that are technically feasible, reduce waste, and protect our public health and environment -- our state will have ignored, denied and discounted years of successful capture of emissions, verified by industry and its experts."
> CAA Ex. 10 at 9-10.

The Department recommends the EIB base its decision the testimony of the parties. At hearing, the Department took no position on the completions/recompletions proposal because the Department lacked sufficient expertise in the area, and recommended the EIB decide the issue based on the testimony of the other parties. 10 Tr. 3380:24-3381:9. In this case, there is more than substantial evidence in the record that the CEP and Oxy's completions/recompletions proposal will reduce VOC and methane emissions, is cost effective, and poses no safety issues. There is no evidence in the record that the proposal is unreasonably costly or that the proposal, as drafted excluding the "vapor tight" language and allowing for a pressure relief system, poses safety risks. Based on the testimony and evidence of the parties, the EIB should adopt the CEP and Oxy's completions/recompletions proposal.

In summary, the proposal is beneficial because:

1. There are substantial uncontrolled emissions during initial flowback. EDF Ex. EE at 26-27, Tables 12 & 13.

2. The proposal is modeled after rules adopted in 2020 by the Colorado Air Pollution Control Commission and the Colorado Oil and Gas Conservation Commission with one significant change, deleting language requiring flowback vessels to be "vapor tight." This change was made to ensure that operators install a pressure relief system to

prevent dangerous static buildup and discharge. 10 Tr. 3232:16-3233:5; 10 Tr. 3307:1-6.

3. EDF witness Tom Alexander and Oxy witness Danny Holderman, an engineer, have managed completions for major oil and gas companies and testified in support of the proposal and that implementation would be safe. 10 Tr. 3232:3-3234:5, -3232:22-3233:5; -3307:1-6.

4. NMOGA's witness John Smitherman attempted to rebut Mr. Alexander and Mr. Holderman's testimony, but his testimony was based on his incorrect characterization that the proposal requires vessels to be "vapor tight" and he gave no testimony that the actual proposal, which allows for a pressure relief system, would be unsafe. 10 Tr. 3319:25-3320:3321:6.

5. EDF analyzed the costs to implement the proposal using a cost-benefit analysis from the Colorado Department of Public Health and the Environment and New Mexico specific data, and found the proposal to be a cost-effective means of mitigating flowback, EDF Ex. SS at 15; EDF Ex. UU at 14; 10 Tr. 3283:1-10, as did Mr. Alexander who found the costs "are very, very reasonable." EDF Ex. UU at 13-14; 10 Tr. 3229:14-3230:17. See also CEP proposed SOR 214-248.

Oxy: Oxy USA supports the proposed Requirements for Flowback Vessels and Preproduction Operations advanced by the e-NGOs as 20.2.50.127 in EDF's Exhibit VV. This proposal would establish emissions standards, monitoring, and recordkeeping obligations related to flowback. Oxy USA appreciates the value of these requirements and believes the proposal is workable for Oxy USA's New Mexico operations.

HISTORY OF 20.2.50 NMAC: [**RESERVED**]