STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

REBUTTAL TESTIMONY OF ELIZABETH BISBEY-KUEHN AND BRIAN PALMER

This rebuttal testimony responds to the technical testimony and proposed revisions submitted by the other parties to this rulemaking on each section of proposed Part 50. References to exhibits submitted with the New Mexico Environment Department's ("Department" or "NMED") Notice of Intent to File Direct Technical Testimony ("NOI") are often referred to by the abbreviations used in the direct testimony. Key exhibits are listed and given abbreviated names on pages 5 through 7 of the direct testimony of Elizabeth Bisbey-Kuehn and Brian Palmer at NMED Exhibit 32.

In addition to the proposed technical revisions discussed in detail below for each section of the proposed rule, the Department has made numerous editorial revisions to Part 50 to correct citation and punctuation errors, align language throughout the rule, and correct minor grammatical errors. All the revisions to Part 50 proposed by the Department as part of this rebuttal testimony are included in NMED Rebuttal Exhibit 2 – Proposed Part 20.2.50 NMAC – September 7, 2021 Redline.

Section 20.2.50.2 - Scope

The Department has proposed several changes to Section 20.2.50.2 based on the testimony and comments submitted by the New Mexico Oil and Gas Association ("NMOGA") and the Independent Petroleum Association of New Mexico ("IPANM").

The Department does not agree with NMOGA's proposal to strike the words "causing or contributing to" from the first sentence of Section 20.2.50.2, as that language is taken directly from the AQCA. *See* NMSA 1978, § 74-2-5(C).

The Department incorporated NMOGA's proposed change to specify the areas of the State that are subject to Part 50 due to having sources that cause or contribute to ozone levels in excess of 95% of the National Ambient Air Quality Standards ("NAAQS"). The Department included Chaves County, because sources in that area contribute to ozone levels in excess of 95% of the NAAQS.

The Department agrees that there will need to be a rulemaking to incorporate sources in other areas of the state into Part 50, and that the effective date of such changes should be at least 180 days from the date of publication of the notice of rulemaking. The Department incorporated NMOGA's changes in Subsection 20.2.50.2(A) specifying certain information that must be included in proposed revisions for a rulemaking to add sources in other areas of the State. The Department also proposed language in Subsection 20.2.50.2(B) 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.

The Department does not agree with NMOGA's proposed language specifying that the notice of rulemaking must include monitoring, testing, or inspection data, and all other technical information necessary to demonstrate that the area or areas of the rule exceed 95% of the NAAQS. The notice requirements in the Board's rulemaking procedures at 20.1.1.301 NMAC are sufficient to provide notice to the public. All technical information will be presented in the rulemaking itself, and therefore, so long as the notice of rulemaking comports with the requirements in 20.1.1.301 NMAC, all interested parties will have the opportunity to participate in the proceeding and review and respond to the evidence presented by the Department in support of the proposed changes.

The Department agrees with NMOGA's proposed language clarifying that if a source's emissions fall below the applicability thresholds contained in specific sections of Part 50, the requirements of that Section no longer apply to that source.

The Department does not agree with NMOGA's proposed change to include "legally and practically enforceable limits" in addition to "federally enforceable limits" as part of provisions of Section 20.2.50.2 that would allow a source to be removed from applicability of Part 50. There are no state-only permits or regulations in New Mexico that are considered by the Department to contain legally and practically enforceable "limits" on PTE that would allow an owner or operator to get out of applicability of Part 50. The Department has had experience with companies trying to argue in federal enforcement actions that certain outdated state regulations provide "legally and practically enforceable" limits. Those arguments were rejected by the Department, the U.S. Environmental Protection Agency ("EPA"), and the U.S. Department of Justice. This experience also shows the potential for NMOGA's proposed language to draw the Department into protracted legal battles over the meaning of its regulations that do not include specific emissions limits. It is the Department's intent that only federally enforceable limits and the applicability thresholds within Part 50 itself should be allowed to be used for purposes of removing a source from applicability of Part 50 based on PTE.

The Department does not agree with IPANM's proposed language requiring the Department to petition the Board to remove areas of the state from the rule if their design values fall below 95% of the standard. The purpose of Part 50, and any regulation promulgated by the Board pursuant to Section 74-2-5 of the AQCA, is to keep areas of the State in compliance with the NAAQS. If ozone concentrations fall below 95% of the NAAQS after the requirements of Part 50 are put into place, the presumption must be that such lowered concentrations are attributable, at least in part, to Part 50 and that removing those requirements would result in concentrations rising again. The requirements of Part 50 must stay in place as institutional controls to keep concentrations within the required health-based national standards.

Section 20.2.50.7 - Definitions

Subsection B. – "Auto-igniter"

NMED agrees with NMOGA's proposal to strike "in the combustion chamber" from the definition. This revision is warranted because open flares do not have, and are not required to have, a combustion chamber.

Subsection C. – "Bleed rate"

NMED agrees with NMOGA's proposal to strike "natural" and "or intermittently" from the definition of "bleed rate" to align with federal and other state interpretations of the term. This revision is appropriate and necessary because pneumatic devices use any pressurized gas, and the term "bleed rate" is used to describe the emissions from high bleed and low bleed continuous pneumatic controllers, not intermittent controllers.

Subsection F. – "Closed vent system"

NMED does not agree with NMOGA's proposal to strike "no" and replace with "minimal" in this definition. This revision is not appropriate because the current definition aligns with the federal requirements in NSPS Subpart OOOOa, and is consistent with the defined term as used in Part 50.

Subsection G. – “Commencement of operation”

NMED does not agree with NMOGA’s proposal to strike “but no later than the end of well completion operation.” This definition is consistent with Colorado Reg. 7, and is consistent with the term as used in Part 50.

Subsection J. – “Construction”

NMED agrees in part with NMOGA’s proposal to exclude relocations, replacements, like kind replacements, temporary installations, and portable stationary sources. NMED has revised the definition to exclude relocations and like kind replacements of existing sources. NMED does not agree with NMOGA’s remaining proposed revisions. NMED intended to include temporary and portable equipment under this Part.

Subsection K. – “Custody transfer”

NMED agrees with NMOGA’s proposal to delete this definition.

Subsection L. – “Control device”

NMED agrees in part with NMOGA’s proposed revisions.

NMED does not agree with NMOGA’s proposal to change the term “vapor recover unit” to “vapor recovery control unit.” NMOGA commented that the term “control” is necessary to distinguish between VRUs used as process equipment and VRUs used as control devices to comply with Part 50. NMED does not believe this distinction is necessary. NMED only intended to regulate VRUs that are used to comply with the emission standards of this Part. Further, the three-factor test adds an additional level of complexity that is unnecessary to determine if a VRU is subject to Part 50. Therefore, this addition is not necessary to clarify that VRUs used to comply with Part 50 are considered control devices. Additional testimony on this subject is provided later in this testimony.

NMED agrees with NMOGA's proposal to delete "air fuel ratio controller" from the definition, as the Department did not intend to regulate these as control devices.

NMED does not agree with NMOGA's proposal to add "equipment for the sole purpose of" before emission reduction, or to delete "equipment" from this definition. Those revisions are not necessary to clarify that other emission reduction equipment can be authorized as control devices.

NMED does not agree with NMOGA's proposed addition of the sentence: "Devices that are only used during malfunction, maintenance, upset, or other temporary events are not considered control devices." NMED intended to regulate devices used in such instances under Part 50. Consistent with federal air regulations, the emission standards of Part 50 apply at all times, including periods of startup, shutdown, and malfunction. NMOGA does not provide a regulatory or technical justification for excluding control devices used during temporary events, and the Department is unable to determine why that exemption would be appropriate. Control devices used to comply with Part 50 may be used for multiple waste gas streams from multiple equipment. The proposed revision would result in owners and operators changing the status of the device under Part 50 for the same piece of equipment, which would result in an excessive amount of tracking and recordkeeping to demonstrate the status of the equipment at the time for a specific event. For example, a control device would be considered regulated if it was used to comply with an emission standard under Part 50 but would be considered unregulated if was used to control emissions during a temporary event. Adding a provision that allows that same control device to be considered exempt simply due to the type of event it is controlling is not consistent with state or federal requirements. Exempting the control device from the requirements that ensure it is operating properly and as intended is unsupported. Regardless of the type of event, control devices used to comply with the emissions standards must be operated properly. Proper operation is determined by monitoring the units in accordance with the requirements of Part 115.

NMED does not agree with NMOGA's proposal to add "in an operating permit" and delete "to comply with emission standards in this Part," to clarify other types of controls approved by the Department. The current language provides the flexibility NMED intended by defining control device to include other control equipment if approved by the Department.

<u>IPANM's Proposed New Definition of "Design Value"</u>

NMED agrees with IPANM's proposal to add this definition, which provides a definition for this term as used in Part 50.

<u>Subsection N. – "Downtime"</u>

NMED agrees with NMOGA's proposal to add "inoperable" and delete "not in operation, or when a well is producing, and the control device is not in operation." These revisions simplify the definition.

<u>Subsection O. – "Enclosed combustion device"</u>

NMED agrees with NMOGA's proposal to delete "gaseous fuel" and replace with "waste gas," add "solely for the purpose of destruction," add "or combustor" and delete "reboiler, and heater." These revisions clarify the meaning of the term and align the language with the Department's regulatory intent.

<u>Subsection Q. – "Gathering and boosting station"</u>

NMED agrees with NMOGA's proposal to add "means a permanent combination of equipment 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," and to delete "or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage." The Department agrees that these revisions clarify the meaning of the defined term.

Subsection S. – "Hydrocarbon liquid"

NMED agrees with NMOGA's proposal to delete "Hydrocarbon liquid does not include produced water." These revisions clarify the Department's intent with respect to this term.

Subsection U. – "Liquid transfer"

NMED agrees with NMOGA's proposal to delete "the loading and" and "or produced water." These revisions clarify the Department's intent with respect to this term.

Subsection W. – "Natural gas compressor station"

NMED does not agree with NMOGA's proposed revisions to this definition. However, NMED has proposed its own revisions which should address NMOGA's concerns.

NMOGA's Proposed New Definition of "Non-Emitting Controller"

NMED agrees with NMOGA's proposal to add a definition of Non-Emitting Controller, and with the definition as proposed by NMOGA. This definition establishes the meaning of the term and the Department's intended use of the term in Part 50.

Subsection DD. – "Permanent pit"

NMED agrees with NMOGA's proposal to add "or pond" to the term, and "or pond" in the definition. These revisions clarify the meaning of the term and the Department's intent with respect to the sources subject to this Part.

Subsection EE. – "Pneumatic controller"

NMED agrees with the proposals of NMOGA, IPANM, and the Gas Compressor Association ("GCA") to revise and add several definitions of different types of controllers within the definition of pneumatic controller. The revisions clarify the defined term and the different types of controllers subject to Part 50. The new definition is as follows:

> 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) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.
> i. "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.
> ii. "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.
> iii. "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.
> iv. "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.

<u>Subsection FF. – "Pneumatic diaphragm pump"</u>

NMED agrees with NMOGA's proposal to delete "natural" from the definition. The revision is appropriate because pumps may use a variety of gases to actuate. The revision clarifies the Department's regulatory intent with respect to this equipment under Part 50.

<u>Subsection GG. – "Potential to emit"</u>

NMED agrees with NMOGA's proposal to delete "contaminant" and replace with "pollutant" and delete "the" and replace with "any." NMED does not agree with NMOGA's request to add "or legally and practically enforceable in an operating permit, authorization, or other requirement established under a federal, state, local, or tribal authority." NMED does 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 a source's potential to emit ("PTE") under Part 50.

Subsection HH. – "Produced water"

NMED agrees with NMOGA's proposal to delete "fluid" and replace with "liquid," and to delete "drilling for or" and replace with "well completion and." These revisions clarify the definition and the Department's intent with respect to the term as used in Part 50.

Subsection II. – "Produced water management unit"

NMED does not agree with NMOGA's proposal to delete "recycling facility" from this definition. NMED intended to include recycling facilities within the meaning of this term as used in Part 50.

NMED agrees with NMOGA's proposal to add "or permanent pond."

NMED does not agree with NMOGA's proposal to add "and associated equipment at that location used for the recycling of produced water." NMED intended to include recycling facilities within this term and as used in this Part.

Subsection MM. – "Recycling facility"

NMED does not agree with NMOGA's proposal to delete this definition. 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.

Subsection NN. – "Responsible official"

NMED agrees with NMOGA's proposal to revise this definition to clarify that an official does not need to be responsible for the overall operation of the source in order to be considered a Responsible Official as that term is used in Part 50.

Subsection OO. – "Small business facility"

NMED does not agree with NMOGA's or IPANM's proposals to delete this definition. NMED has provided extensive testimony on the need for this definition in order to implement the requirements of Part 50 and provide regulatory relief to certain owners and operators that meet the criteria specified in this definition.

NMOGA's Proposed New Definition of "Stabilized"

NMED does not agree with NMOGA's proposal to add this definition. This definition is unnecessary given that the term is not used anywhere in Part 50.

Subsection RR. – "Storage vessel"

NMED agrees with NMOGA's proposal to add "or" to distinguish between truck or railcar. NMED agrees with NMOGA's proposal to add "(29.274 psi) to provide a different unit of pressure in the definition. NMED does not agree with NMOGA's proposal to add "A storage vessel does not include a storage vessel located at a saltwater disposal facility unless a storage vessel is associated with a produced water management unit." This revision is not necessary because the Department has clarified that saltwater disposal facilities are not intended to be regulated under Part 50.

NMOGA's Proposed New Definition of "Tank Battery"

NMED does not agree with NMOGA's proposal to add this definition. The definition is unnecessary as the term is well understood by the regulated industry and it is not necessary to clarify any requirements within Part 50.

NMOGA's Proposed New Definition of "Vapor Recovery Control Unit"

NMED does not agree with NMOGA's proposal to add this definition. The definition is unnecessary as 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. Thus, there is already an affirmative record if a VRU is being used as a control device to comply with this Part. That documentation suffices to make the distinction. No additional definitions or documentation are necessary to make this distinction.

Subsection UU. – "Wellhead site"

NMED does not agree with NMOGA's proposal to revise this definition. NMED has this definition in the July 28, 2021 version of the proposed rule to replace "Wellhead" with "Well". Those revisions should address NMOGA's comments that wellhead site may not include any equipment.

Section 20.2.50.7 - Definitions

Subsection B. – "Auto-igniter"

NMED agrees with NMOGA's proposal to strike "in the combustion chamber" from the definition. This revision is warranted because open flares do not have, and are not required to have, a combustion chamber.

Subsection C. – "Bleed rate"

NMED agrees with NMOGA's proposal to strike "natural" and "or intermittently" from the definition of "bleed rate" to align with federal and other state interpretations of the term. This revision is appropriate and necessary because pneumatic devices use any pressurized gas, and the term "bleed rate" is used to describe the emissions from high bleed and low bleed continuous pneumatic controllers, not intermittent controllers.

Subsection F. – "Closed vent system"

NMED does not agree with NMOGA's proposal to strike "no" and replace with "minimal" in this definition. This revision is not appropriate because the current definition aligns with the federal requirements in NSPS Subpart OOOOa, and is consistent with the defined term as used in Part 50.

Subsection G. – "Commencement of operation"

NMED does not agree with NMOGA's proposal to strike "but no later than the end of well completion operation." This definition is consistent with Colorado Reg. 7, and is consistent with the term as used in Part 50.

Subsection J. – "Construction"

NMED agrees in part with NMOGA's proposal to exclude relocations, replacements, like kind replacements, temporary installations, and portable stationary sources. NMED has revised the definition to exclude relocations and like kind replacements of existing sources. NMED does not agree with NMOGA's remaining proposed revisions. NMED intended to include temporary and portable equipment under this Part.

Subsection K. – "Custody transfer"

NMED agrees with NMOGA's proposal to delete this definition.

Subsection L. – "Control device"

NMED agrees in part with NMOGA's proposed revisions.

NMED does not agree with NMOGA's proposal to change the term "vapor recover unit" to "vapor recovery control unit." NMOGA commented that the term "control" is necessary to distinguish between VRUs used as process equipment and VRUs used as control devices to comply with Part 50. NMED does not believe this distinction is necessary. NMED only intended to regulate VRUs that are used to comply with the emission standards of this Part. Further, the three-factor test adds an additional level of complexity that is unnecessary to determine if a VRU is subject to Part 50. Therefore, this addition is not necessary to clarify that VRUs used to comply with Part 50 are considered control devices. Additional testimony on this subject is provided later in this testimony.

NMED agrees with NMOGA's proposal to delete "air fuel ratio controller" from the definition, as the Department did not intend to regulate these as control devices.

NMED does not agree with NMOGA's proposal to add "equipment for the sole purpose of" before emission reduction, or to delete "equipment" from this definition. Those revisions are not necessary to clarify that other emission reduction equipment can be authorized as control devices.

NMED does not agree with NMOGA's proposed addition of the sentence: "Devices that are only used during malfunction, maintenance, upset, or other temporary events are not considered control devices." NMED intended to regulate devices used in such instances under Part 50. Consistent with federal air regulations, the emission standards of Part 50 apply at all times, including periods of startup, shutdown, and malfunction. NMOGA does not provide a regulatory or technical justification for excluding control devices used during temporary events, and the Department is unable to determine why that exemption would be appropriate. Control devices used to comply with Part 50 may be used for multiple waste gas streams from multiple equipment. The proposed revision would result in owners and operators changing the status of the device under Part 50 for the same piece of equipment, which would result in an excessive amount of tracking and recordkeeping to demonstrate the status of the equipment at the time for a specific event. For example, a control device would be considered regulated if it was used to comply with an emission standard under Part 50 but would be considered unregulated if was used to control emissions during a temporary event. Adding a provision that allows that same control device to be considered exempt simply due to the type of event it is controlling is not consistent with state or federal requirements. Exempting the control device from the requirements that ensure it is operating properly and as intended is unsupported. Regardless of the type of event, control devices used to comply with the emissions standards must be operated properly. Proper operation is determined by monitoring the units in accordance with the requirements of Part 115.

NMED does not agree with NMOGA's proposal to add "in an operating permit" and delete "to comply with emission standards in this Part," to clarify other types of controls approved by the Department. The current language provides the flexibility NMED intended by defining control device to include other control equipment if approved by the Department.

IPANM's Proposed New Definition of "Design Value"

NMED agrees with IPANM's proposal to add this definition, which provides a definition for this term as used in Part 50.

Subsection N. – "Downtime"

NMED agrees with NMOGA's proposal to add "inoperable" and delete "not in operation, or when a well is producing, and the control device is not in operation." These revisions simplify the definition.

Subsection O. – "Enclosed combustion device"

NMED agrees with NMOGA's proposal to delete "gaseous fuel" and replace with "waste gas," add "solely for the purpose of destruction," add "or combustor" and delete "reboiler, and heater." These revisions clarify the meaning of the term and align the language with the Department's regulatory intent.

Subsection Q. – "Gathering and boosting station"

NMED agrees with NMOGA's proposal to add "means a permanent combination of equipment 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," and to delete "or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage." The Department agrees that these revisions clarify the meaning of the defined term.

Subsection S. – "Hydrocarbon liquid"

NMED agrees with NMOGA's proposal to delete "Hydrocarbon liquid does not include produced water." These revisions clarify the Department's intent with respect to this term.

Subsection U. – "Liquid transfer"

NMED agrees with NMOGA's proposal to delete "the loading and" and "or produced water." These revisions clarify the Department's intent with respect to this term.

Subsection W. – "Natural gas compressor station"

NMED does not agree with NMOGA's proposed revisions to this definition. However, NMED has proposed its own revisions which should address NMOGA's concerns.

NMOGA’s Proposed New Definition of “Non-Emitting Controller”

NMED agrees with NMOGA’s proposal to add a definition of Non-Emitting Controller, and with the definition as proposed by NMOGA. This definition establishes the meaning of the term and the Department’s intended use of the term in Part 50.

Subsection DD. – “Permanent pit”

NMED agrees with NMOGA’s proposal to add “or pond” to the term, and “or pond” in the definition. These revisions clarify the meaning of the term and the Department’s intent with respect to the sources subject to this Part.

Subsection EE. – “Pneumatic controller”

NMED agrees with GCA’s, NMOGA’s, and IPANM’s proposals to revise and add several definitions of different types of controllers within the definition of pneumatic controller. The revisions clarify the defined term and the different types of controllers subject to Part 50. The new definition is as follows:

> 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) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.
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> i. "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.
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> ii. "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.
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> iii. “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.
>
> iv. “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.

Subsection FF. – “Pneumatic diaphragm pump”

NMED agrees with NMOGA's proposal to delete "natural" from the definition. The revision is appropriate because pumps may use a variety of gases to actuate. The revision clarifies the Department's regulatory intent with respect to this equipment under Part 50.

Subsection GG. – "Potential to emit"

NMED agrees with NMOGA's proposal to delete "contaminant" and replace with "pollutant" and delete "the" and replace with "any." NMED does not agree with NMOGA's request to add "or legally and practically enforceable in an operating permit, authorization, or other requirement established under a federal, state, local, or tribal authority." NMED does 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.

Subsection HH. – "Produced water"

NMED agrees with NMOGA's proposal to delete "fluid" and replace with "liquid," and to delete "drilling for or" and replace with "well completion and." These revisions clarify the definition and the Department's intent with respect to the term as used in Part 50.

Subsection II. – "Produced water management unit"

NMED does not agree with NMOGA's proposal to delete "recycling facility" from this definition. NMED intended to include recycling facilities within the meaning of this term as used in Part 50.

NMED agrees with NMOGA's proposal to add "or permanent pond."

NMED does not agree with NMOGA's proposal to add "and associated equipment at that location used for the recycling of produced water." NMED intended to include recycling facilities within this term and as used in this Part.

Subsection MM. – "Recycling facility"

NMED does not agree with NMOGA's proposal to delete this definition. 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.

Subsection NN. – "Responsible official"

NMED agrees with NMOGA's proposal to revise this definition to clarify that an official does not need to be responsible for the overall operation of the source in order to be considered a Responsible Official as that term is used in Part 50.

Subsection OO. – "Small business facility"

NMED does not agree with NMOGA's or IPANM's proposals to delete this definition. NMED has provided extensive testimony on the need for this definition in order to implement the requirements of Part 50 and provide regulatory relief to certain owners and operators that meet the criteria specified in this definition.

NMOGA's Proposed New Definition of "Stabilized"

NMED does not agree with NMOGA's proposal to add this definition. This definition is unnecessary given that the term is not used anywhere in Part 50.

Subsection RR. – "Storage vessel"

NMED agrees with NMOGA's proposal to add "or" to distinguish between truck or railcar. NMED agrees with NMOGA's proposal to add "(29.274 psi) to provide a different unit of pressure in the definition. NMED does not agree with NMOGA's proposal to add "A storage vessel does not include a storage vessel located at a saltwater disposal facility unless a storage vessel is associated with a produced water management unit." This revision is not necessary because the Department has clarified that saltwater disposal facilities are not intended to be regulated under Part 50.

<u>NMOGA's Proposed New Definition of "Tank Battery"</u>

NMED does not agree with NMOGA's proposal to add this definition. The definition is unnecessary as the term is well understood by the regulated industry and it is not necessary to clarify any requirements within Part 50.

<u>NMOGA's Proposed New Definition of "Vapor Recovery Control Unit"</u>

NMED does not agree with NMOGA's proposal to add this definition. The definition is unnecessary as the term "Vapor Recovery Unit" 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. Thus, there is already an affirmative record if a VRU is being used as a control device to comply with this Part. That documentation suffices to make the distinction. No additional definitions or documentation are necessary to make this distinction.

<u>Subsection UU. – "Wellhead site"</u>

NMED does not agree with NMOGA's proposal to revise this definition. NMED has this definition in the July 28, 2021 version of the proposed rule to replace "Wellhead" with "Well". Those revisions should address NMOGA's comments that a wellhead site may not include any equipment.

Section 20.2.50.112 – General Provisions

<u>Subsection A – General Requirements</u>

Paragraph 1

NMOGA proposes to strike the term "source" and replace with "unit" in this section and throughout Part 50. For the reasons provided in the rebuttal testimony on the definition of the term "source" in Section 20.2.50.7, NMED does not agree with this proposed revision.

NMOGA presented testimony that owners and operators should have the option to use of good operational and maintenance practices as an alternative to manufacturers' specifications, and proposed clarifying language throughout Part 50 to allow for the use of this alternative. NMED agrees with that owners or operators should be able 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. NMED has proposed revisions to Paragraph 1 of Subsection 20.2.50.112.A that provide for the use of alternative specifications and practices, and clarify that wherever the term "manufacturer specification" is used throughout Part 50, it encompasses such alternatives.

Paragraph 2

IPANM proposes to strike the general requirement owners and operators to operate sources in a manner that minimizes the emissions of ozone precursors in its entirety, but does not provide a basis for this proposal. NMED does not agree with IPANM's proposal to remove this requirement because it establishes a reasonable obligation on the part of owners and operators.

NMOGA proposes revisions to this provision, which NMED agrees with. The revisions clarify the sources covered and specify that the requirement applies at all times, including during periods of startup, shutdown, and malfunctions. The revisions also 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.

Paragraphs 3 through 9

These paragraphs contain the Department's proposal for tracking and recording monitoring, testing, and inspection events using scannable Equipment Monitoring Tags ("EMT"), and a database system capable of generating Compliance Data Reports ("CDR") that can be provided to the Department upon request. IPANM and GCA propose to remove this requirement in its entirety, while NMOGA and Oxy USA propose revisions that would eliminate the EMT requirements and require owners and operators to maintain a database system to store the specified compliance information.

NMED does not agree with the proposals to remove these paragraphs in their entirety. This provision establishes a reasonable requirement for all owners and operators subject to Part 50 to operate and maintain a database 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 the Department'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 has proposed revisions to address the concerns raised by industry relating to the EMT system. The revisions remove the requirement to place a physical tag on each affected source, but maintain the requirement to establish a database system to maintain compliance information as well as other general information for each those sources.

NMED does not agree to remove requirements that each monitoring event be contemporaneously recorded and then uploaded to the database system. 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. NMED will establish a workgroup with representatives of the affected stakeholders to develop a list of approved methods to meet this requirement. The new proposed language in this Section requires NMED to finalize the list of approved technologies by January 1, 2023 and to post that information on its website. By April 1, 2023, owners and operators subject to these requirements must use one of the Department approved methods to comply with this requirement. Prior to April 1, 2023, owners and operators may comply with this requirement with a written or electronic record of the date and time of any affected monitoring event.

Paragraph 10

This provision allows the Department to require an owner or operator to retain a third party to review a CDR in order to verify compliance with Part 50 and provide recommendations on how to improve compliance. IPANM proposes to delete this requirement in full, and presents testimony on costs for this type of audit, without providing any details or supporting exhibits. NMOGA proposes revisions that would allow owners and operators to request a hearing to review whether good cause was established by the Department for requiring a third party audit and/or the recommendations made by the third party auditor. Oxy USA requests to limit these types of requests to once per year.

NMED does not agree with IPANM's proposal to delete this requirement as it 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 agrees to limit these types of requests to once per year and to add language providing that the owner or operator may request a hearing to allow for review of the Department's asserted cause for requesting the 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.

New Paragraphs 10 and 11

NMED proposes to add two additional paragraphs to Subsection A of 20.2.50.112 NMAC. The first paragraph 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. This provision 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.

The second paragraph requires owners or operators to review Part 50 for applicability prior to modifying an existing source. This was not clear in the initial draft and 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 units that may become subject to Part 50 as a result of such modifications.

<u>Subsection B - Monitoring Requirements</u>

Paragraphs 1 and 2

NMOGA proposes revisions to replace “monitoring” with “monitoring, testing, or inspection” in the header of this subsection and throughout Part 50. NMED has made the following revisions to paragraph 20.2.50.112.B(1) in order to address this comment and possible confusion: “Unless otherwise specified, the term monitoring as used in this Part includes but is not limited to monitoring, testing, or inspection requirements.” This revisions addresses the NMOGA’s proposal both in Section 20.2.50.112 as well as the other parts of the rule where NMOGA proposes similar revisions.

Paragraph 3

NMED agrees with NMOGA’s proposal to add “authorized representative” after owner or operator.

NMED agrees with NMOGA's proposed revisions to delete the reference to the EMT and streamline the language in this paragraph to require owners and operators to record the information as required by the applicable sections of Part 50. This revision also addresses Oxy USA's proposal to exempt alternative monitoring from EMT requirements, and IPANM's request to delete this requirement.

<u>Subsection C – Recordkeeping Requirements</u>

Paragraph 1

NMOGA proposes revisions to account for when final reports are received; to delete the general recordkeeping requirements; and to clarify that owners and operators must comply with the recordkeeping requirements specified in each applicable section of Part 50. NMED agrees with these proposed revisions.

Paragraph 2

NMOGA proposes to delete the last sentence from this requirement, which states that loss of data or failure to keep a record shall be treated as a failure to collect the data. NMOGA provides no justification or rationale for this proposed revision. NMED does not agree with this revision. This provision codifies the Department's standard practice to presume that loss of data or failure to retain a record is a failure to collect the data. Both types of violations – failure to collect/record information and failure to retain information – are assigned equal gravity under the Air Quality Bureau's civil penalty policy.

Paragraph 3

NMOGA and Oxy USA propose to delete the requirement that an owner or operator complete a full compliance evaluation prior to a transfer of equipment subject to Part 50. NMED agrees to remove this requirement based on the issues raised by these parties. Instead, NMED has added a new provision requiring 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.

Reporting Requirements

NMOGA and Oxy USA propose revisions to allow three business days for responding to requests from the Department, and to allow additional time if CDRs are requested of multiple facilities, if appropriate. NMED agrees with these proposed revisions as the timeframes are reasonable, and additional time may be warranted if a records request affects multiple facilities.

Section 20.2.50.113 – Engines and Turbines

Subsection A - Applicability

NMOGA proposes to add a statement that non-road engines that meet the federal definition of non-road engines are not subject to this Part. NMED agrees with this revision as it clarifies the intended applicability of the rule.

Kinder Morgan, Inc. ("Kinder Morgan") proposes to add "in areas of the State specified in 20.2.50.2 NMAC" to this subsection. NMED disagrees with this revision as it is unnecessary and redundant. Section 20.2.50.2 already limits applicability of all sections of Part 50 to sources located in the specified areas of the State.

Subsection B – Emission Standards

Paragraph 1

NMOGA proposes to add a statement that owners and operators may comply with an Alternative Compliance Plan ("ACP") for engines. NMED agrees with this revision, as explained in detail later in the testimony on Section 20.2.50.113.

Paragraph 2

NMOGA and Oxy USA propose revisions to clarify that owners and operators must inventory engines "subject to Part 50." NMED agrees with this clarifying revision.

NMOGA proposes to add an exception from the specified inventory and schedules in this paragraph if approved through an ACP. NMED agrees that this revision is warranted.

In subparagraph (d), NMOGA and Kinder Morgan proposed to add "PTE for" in front of NOx, and language that allows owners and operators to reduce the annual operating hours to achieve an equivalent reduction in emissions to those reductions required by the emission standards. NMED agrees with these clarifying revisions.

NMOGA and Kinder Morgan propose revisions to Table 1 to remove the word "installed" from the title, and to base the threshold for new versus existing engines on the date of construction or reconstruction (i.e., the date of engine manufacture or remanufacture). Engines would not be considered new if they were moved and "installed" at a new location. NMED agrees to delete the term "installed." In addition, the definition of "construction" was revised to clarify that relocations and like-kind replacements do not trigger new requirements under Part 50. NMED agrees with the testimony of the GCA representing compression service providers who described how engines that are part of compressor packages in the gathering and boosting segment can be moved from site to site as needed with no reconstruction or modification of the engine itself.

NMOGA and Kinder Morgan propose revisions to Subparagraph (e) to allow submission of a justification establishing the technical impracticability or economic infeasibility of requiring certain equipment to comply with the emission standards of this Section. The proposal includes timelines within which the Department would be required to review and approve the exemption, and an automatic approval if the Department fails to act within those timelines. Both parties also proposed revisions allowing owners and operators additional time to comply with the emissions standards if good cause is shown.

The current proposal offers flexibility for sources that are unable to meet the emission standards of this Part by allowing owners and operators to reduce the annual hours of operation. NMED is also proposing revisions to address the issues of technical impracticability and economic infeasibility by providing additional flexibilities in the rule. Specifically, NMED has proposed provisions allowing for submission of Alternative Compliance Plans, as detailed in later in this testimony. NMED has also included provisions that allow owners and operators to apply for alternative emissions standards for an individual engine or turbine where the owner or operator can demonstrate that it cannot meet the emissions standards through an ACP. NMED believes that this suite of alternatives offers sufficient flexibility to owners and operators to meet the requirements of this Part.

Regarding extension of the compliance deadlines, NMED disagrees with this proposal. The compliance deadlines as currently proposed provide sufficient time for owners and operators to comply with the requirements of this Part. The staggered compliance deadlines extend through 2029, giving owners and operators nearly eight years to fully comply with the emission standards.

Table 1 – Emission Standards for Existing Engines

NMOGA, Kinder Morgan, and GCA propose to modify the emission standards for certain categories of existing engines and to further differentiate among different types and sizes of engines. NMED has proposed revised emissions limits based on the information provided in the direct testimony of NMOGA and GCA on engine control technology, and a further analysis of stack emissions testing data available from Ohio and the NMED Equipment Data. The revised Table 1 is as follows:

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR RECONSTRUCTED ON OR BEFORE THE EFFECTIVE DATE OF 20.2.50 12 NMAC.

Engine Type	Engine Size (bhp)	Emission Standards (g/bhp-hr)		
		NOx	CO	NMNEHC
2-Stroke Lean Burn	>1,000 bhp	3.0	0.60	0.70
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	2.0	0.60	0.70
4-Stroke Lean Burn	≥1,775 bhp	0.5	0.60	0.70
4-Stroke Rich Burn	>1,000 bhp	0.5	0.60	0.70

NMED acknowledges the technical testimony from GCA and NMOGA that the most common 4-stroke lean-burn engines greater than 1,000 hp are manufactured by Caterpillar and are differentiated into two model series – 3500 and 3600. The 3500 series are smaller in size than the 3600 series and have a smaller cylinder bore diameter and cylinder head that cannot accommodate the same precombustion chamber ("PCC") technology like the 3600 series engines can. A PCC is an important element for reducing NOx emissions from spark ignition engines. As a result, the 3500 series engines are not able to meet as stringent a NOx emission limit as the 3600 series engines. Waukesha VHP7042GL lean-burn engines are also not PCC engines. *See* NMOGA Appendix A3 – Direct Testimony of Justin Lisowski, VALOR EPC Study: NMAC 20.2.50.113, Engines and Turbines ("VALOR Engine Study"), at p. 5. The NMED Equipment Data indicate that 234 Waukesha VHP7042GL lean-burn engines are operating in New Mexico, but the maximum horsepower of these New Mexico engines is 1,547 hp. No Waukesha VHP7042GL lean-burn engines were represented in the Ohio stack test data (although several Waukesha 7042 and 7044 rich-burn engines were included in the Ohio data). We have assumed that these Waukesha VHP7042GL could meet the revised NOx limit of 2.0 g/hp-hr for 4-stroke lean-burn engines less than 1,775 hp and would have no costs associated with meeting those limits.

ERG examined equipment data for compressor engines located in New Mexico and emission stack test data for compressor engines located in Ohio. The New Mexico equipment data were included as NMED Exhibit 056 – ICE Reductions-and-Costs-NO2-6-4-21-erg-06-08-2021.xlsx. The Ohio data summaries are available from 2003 to 2016 in Microsoft Excel spreadsheet format on the Ohio Environmental Protection Agency's website at the following link https://epa.ohio.gov/dapc/engineer/stackg#123883452-test-summaries.

The Ohio stack test data for compressor engines were provided in NMED Exhibit 051 – Engines and Turbines_OH_StackTests.xlsx. ERG further analyzed and summarized this data to develop this rebuttal testimony. The updated spreadsheet of the Ohio data is included as NMED Rebuttal Exhibit 3. A detailed summary of the NOx data is also included in NMED Rebuttal Exhibit 3.

The Ohio test data represent some engines that were tested annually over multiple years, while other engines were tested only once. In order to avoid skewing the data towards the engines that were tested multiple times, ERG determined the average emission rate for each engine and used that rate for the analysis. The measured emission rates were then compared to the NOx emission limits included in the revised Table 1 to Section 20.2.50.113. A summary of the results of the analysis of the NOx data is presented in Figure 1 below:

Engine Type	Engine Size (bhp)	Number of engines tested	Revised Limit (g NOx/hp-hr)	Number of engines testing lower than the revised limit	% Testing below the revised limit
2-Stroke Lean Burn	>1,000 bhp	14	3.0	6	43%
4-Stroke Lean Burn	>1,000 bhp and <1,775 bhp	11	2.0	11	100%

4-Stroke Lean Burn	≥1,775 bhp	91	0.5	87	96%
4-Stroke Rich Burn	>1,000 bhp	83	0.5	72	87%

Figure 1 – Summary Table of NOx Data Analysis Results

The New Mexico Equipment Data and the Ohio test data both indicate that many of the existing 4-stroke lean-burn Caterpillar 3600 series engines have horse-power ratings of 1,775 and above. This is contrary to the direct testimony from GCA and NMOGA which indicated that the Caterpillar 3600 series engines have horse-power ratings of 1,875 and above. However, that discrepancy may be due to a difference between older engines and newer engines. ERG has assumed that the 1,775 hp rating for 3600 series engines is accurate for many existing engines, while the 1,875 hp rating is accurate for some newer engines and all engines that will be manufactured after the effective date of Part 50 and subject to new engine emission limits.

The summary table in Figure 1 indicates that among the 4-stroke lean-burn engines, all engines between 1,000 and 1,775 hp could meet an emission limit of 2.0 g/hp-hr, and 96 percent of engines with 1,775 hp or greater could meet a limit of 0.5 g/hp-hr. The data summary excluded four 4-stroke lean-burn engines of unknown manufacture that all tested between 7 and 14 g/hp-hr. All of the other 4-stroke lean-burn engines were Caterpillars.

According to the direct testimony of GCA witness Vic Sheldon, the larger G3600A4 LE engine began its manufacture in 1991 with an integrated pre-combustion chamber. *See* GCA Exhibit 9 at p. 7. The NMED Equipment Data includes 661 Caterpillar engines that are model number 3600 or higher, 362 of which have manufacture or construction dates, and all those dates are more recent than 1991. Therefore, it is likely that many of these existing Caterpillar 3600-series engines would be able to meet the revised NOx standard of 0.5 g/hp-hr for 4-stroke lean-burn engines greater than 1,775 hp. In the NMED Equipment Data, 260 Caterpillar engines of all sizes are designated as “LE” for low emission, and ERG has assumed that these engines can meet the revised 4-stroke lean-burn NOx limits of 2.0 g/hp-hr for engines less than 1,775 hp and 0.5 g/hp-hr for engines equal to or greater than 1,775 hp.

After removing the costs for Waukesha VHP7042GL engines and Caterpillar “LE” engines, the total estimated annual cost of the NOx controls for internal combustion engines, based on low emission combustion retrofits for lean burn engines, is reduced from $120 million to $104 million. Annual costs for the remaining Caterpillar engines account for $91 million of the remaining $104 million in annual control costs. Based on the GCA and NMOGA testimony and the stack test data from Ohio, it is likely that many, if not most, of the remaining Caterpillar engines and the Waukesha 4-stroke rich burn engines could meet the revised NOx emission limit with little or no low emission combustion retrofits, and the total annual control costs are significantly lower than originally estimated. Total annual costs for the 120 engines that are not Caterpillar or Waukesha are about $10 million; 41 of these are 2-stroke lean-burn engines, 52 are 4-stroke lean-burn, 13 are 4 stroke rich-burn (three have catalytic converters), and the rest are an unknown engine type.

The revised NOx limits for existing 2-stroke lean-burn engines (3.0 g/hp-hr) and 4-stroke rich-burn engines (0.5 g/hp-hr) are consistent with the NOx limits recommended by NMOGA and GCA in their testimony, excluding the more stringent limits for 4-stroke lean-burn engines described above.

The limits in the Table 1 for CO have been revised so that the limits for rich-burn and lean-burn engines are the same limit of 0.60 g/hp-hr. The limits in the Table 1 for NMNEHC remain the same as the May 6, 2021 proposal. The limits for CO and NMNEHC are consistent with the recommended limits in the redline markup of the rule submitted by GCA with its direct testimony.

NMOGA recommended that the CO limit be either removed from Table 1 because it is not an ozone precursor, or raised to 2.0 g/hp-hr for lean burn engines to reflect the same limit in 40 CFR 60, subpart JJJJ. Kinder Morgan proposed the same CO limit in their redline markup. NMED rejects these proposed revisions. A properly designed and operating catalytic oxidizer should be reducing both CO and NMNEHC emissions. Therefore, NMED is retaining the limit for CO in Table 1 as an important indicator of catalytic oxidizer performance. In addition, the emission testing requirements authorize CO to be used as a surrogate for determining compliance with the NMNEHC emission standards. These CO and NMNEHC limits are readily achievable with the use of catalytic oxidation on all engine types as demonstrated in the Ohio stack test data included as NMED Rebuttal Exhibit 3.

Table 2 – Emission Standards for New Engines

Kinder Morgan, GCA, and NMOGA propose modifications to the emission standards and horsepower thresholds for certain categories of new engines. NMED agrees to revise the emission standards and horsepower thresholds for new engines as follows:

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR RECONSTRUCTED AFTER THE EFFECTIVE DATE OF 20.2.50 12 NMAC.

Engine Type	Engine Size (bhp)	Emission Standards (g/bhp-hr)		
		NOx	CO	NMNEHC
Lean Burn	>500 bhp and <1,875 bhp	0.5	0.60	0.70
Lean Burn	≥1,875 bhp	0.3	0.60	0.70
Rich Burn	>500 bhp	0.5	0.60	0.70

The revised limits in Table 2 are the same as those recommended by GCA, but also reflect most, though not all, of the recommendations from Kinder Morgan and NMOGA. The revisions to Table 2 include a break at 1,875 hp for the more stringent NOx emission limit at 0.3 g/hp-hr. It is not necessary to establish this break at 2,370 or 2,500 hp because the "new" engine applicability will be based only on the construction or reconstruction date, and will not be affected by installation of existing engines at new locations.

The revised Table 2 does not include an alternative limit of 0.05 g/hp-hr for "controlled" lean burn engines that are greater than or equal to 1,875 hp because the testimony from GCA, Kinder Morgan, and NMOGA, along with the New Mexico Equipment Data and the stack test data from Ohio, all indicate that post-combustion controls for NOx are not feasible at this time for these lean burn engines, and are not being used by any of the engines for which we have data.

NMED is not increasing the lower horsepower limits for new lean-burn and rich-burn engines from 500 hp to 1,000 hp, as proposed by Kinder Morgan and NMOGA in their redline markups, because neither party presented testimony or data specifically addressing and supporting that change. That change was not recommended by GCA. The 500 hp lower threshold for new engines is included in Colorado's Reg. 7 at Part E, which requires the installation of selective noncatalytic oxidation and an air fuel ratio controller on all lean burn and rich burn engines greater than 500 hp. Pennsylvania's GP- 5 and GP-5A include emission limits for all new lean burn and rich burn engines with no lower hp cut off, but include more stringent emission limits for engines at a threshold of greater than 500 hp.

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.

Paragraph 7

Kinder Morgan and NMOGA propose to add a new requirement for existing turbines, similar to the proposal for existing engines. The proposed revisions would require owners and operators to complete an inventory of all existing turbines subject to Part 50, and prepare a schedule to ensure each subject turbine meets the emission standards in Table 3 by the deadlines set forth in the proposal. The proposed new provisions include an option for owners and operators to comply with the emission standards through an Alternative Compliance Plan, similar to the concept requested for engines and agreed to by NMED. The proposed new provisions also 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. The proposal includes requirements for when the Department would be required to review and approve the exemption, and an automatic approval if the Department fails to act within certain timelines. Both parties also requested revisions allowing for additional time to comply with the emission standards if good cause is shown.

NMED has carefully reviewed these requests and agrees with the proposed revisions regarding the existing turbine inventory, staggered compliance deadlines, and the option to use an ACP. NMED has proposed language in Paragraph 11 of this Subsection allowing 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 Department does not agree with the proposal to add the option for an extension of time to comply based on good cause 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.

Table 3 – Emission Standards for Existing and New Turbines

Kinder Morgan and NMOGA propose to add clarifying language in the Table header and modify the emission standards and horsepower thresholds for certain categories of existing and new turbines. The Department also received a letter from Solar Turbines ("Solar") outlining a similar proposal. *See* NMED Rebuttal Exhibit 4 – Letter dated July 13, 2021 to Liz Bisbey-Kuehn from Solar Turbines. NMED agrees with the proposal to add clarifying language and revise the emissions standards and horsepower thresholds for existing and new turbines in Table 3, as follows:

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

<table>
<tr><td colspan="4">For each applicable natural gas-fired combustion turbine constructed or reconstructed 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:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NOx (ppmvd @ 15% O_2)</td><td>CO (ppmvd @ 15% O_2)</td><td>NMNEHC (ppmvd @ 15% O_2</td></tr>
<tr><td>≥1,000 and <4,000</td><td>150</td><td>50</td><td>9</td></tr>
<tr><td>≥4,000 and <15,000</td><td>50</td><td>50</td><td>9</td></tr>
<tr><td>≥15,000</td><td>50</td><td>50 or 93% reductions</td><td>5 or 50% reduction</td></tr>
<tr><td colspan="4">For each applicable natural gas-fired combustion turbine constructed or reconstructed before 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:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NOx (ppmvd @ 15% O_2)</td><td>CO (ppmvd @ 15% O_2)</td><td>NMNEHC (ppmvd @ 15% O_2</td></tr>
<tr><td>≥1,000 and <4,000</td><td>100</td><td>25</td><td>9</td></tr>
<tr><td>≥4,000 and <15,900</td><td>15</td><td>25</td><td>9</td></tr>
<tr><td>≥15,900</td><td>9</td><td>25</td><td>5</td></tr>
</table>

As it did for engines, NMED has revised the applicability language in Table 3 to remove references to "installed" turbines so that the standards for existing and new turbines will depend on the date the turbine is constructed or reconstructed, and relocated turbines will not be subject to the same standards as new or reconstructed turbines.

NMED is not revising the applicability threshold to remove turbines rated between 1,000 and 4,000 hp, as requested by NMOGA. Although the turbines in this size range (1,000 to 4,000 hp) account for about 50% of the total number of turbines in New Mexico that are greater than 1,000 hp, they also account for 20% of the total horsepower of all turbines greater than 1,000 hp, and if unregulated would account for a disproportionate amount of the emissions from turbines.

The revised emission limits for NOx in Table 3 for existing turbines equal to or greater than 1,000 hp and less than 4,000 hp (150 ppmvd at 15% O_2) is the same as that recommended by Solar Turbines, and is the same as the limit in Colorado's Reg. 7 for existing turbines firing natural gas and less than or equal to 50 MMBtu/hr. The NOx limit for new or reconstructed turbines (100 ppmvd at 15% O_2) is the same as the limit for reconstructed turbines in the federal NSPS regulations at 40 C.F.R. 60, Subpart KKKK. NMED is also accepting 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 4,000 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 NMED Equipment Data includes 137 turbines, 121 of which are manufactured by Solar. Revising the emission limits for turbines less than 4,000 bhp would lower the estimated compliance costs (which were based on steam injection instead of dry low NOx retrofits) by about $9.5 million, from an estimated total of $13.5 million. NMED agrees with Solar's letter that water or steam injection would not be feasible because of the availability and cost of large volumes of deionized water needed, especially at remote sites.

NMED does not agree with the proposal to delete the CO emission standards for turbines. The emission testing requirements authorize CO to be used as a surrogate for determining compliance with the NMNEHC emission standards. These standards are in place for subject engines and should also remain in effect for turbines. Alternatively, NMED could propose to remove the CO emission standards and require EPA reference method testing for NMNEHC.

Paragraph 9

NMED has proposed revisions to delete the requirement to install an equipment monitoring tag.

Former Paragraph 10, New Paragraph 9

NMED has proposed revisions to add references to the federal regulations for non-road engines.

New Paragraph 10 and 11

NMOGA and Kinder Morgan propose to add a new provision authorizing an Alternative Compliance Plan for engines and turbines. This proposal 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 agrees with this proposal and has revised this provision and expanded upon the language suggested by the industry groups. NMED has added two requirements that are fundamental to making an 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.

As discussed above, NMED agrees to add a provision for owners and operators to request an alternative emission standard for individual engines and turbines that cannot meet equivalent emission reductions under an ACP. 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.

New Paragraph 12

NMOGA proposes revisions to allow for the use of short-term engine replacements, as authorized under the Board's regulations for new source review and general construction permits at 20.2.72 NMAC. NMED agrees with these revisions as they address the need for owners and operators to replace engines on a short-term basis, and align with the authorizations of the permits.

<u>Subsection C – Monitoring Requirements</u>

Paragraph 1

GCA, Kinder Morgan, and NMOGA propose to add language that clarifies what types of maintenance requirements may be used to comply with Part 50. This proposal is addressed in NMED's proposed revisions to Section 20.2.50.112 regarding what qualifies as a manufacturer specification.

New Paragraph 2

GCA, Kinder Morgan, and NMOGA propose to add a provision that engines and turbines following a maintenance plan consistent with an applicable federal NSPS or NESHAP should satisfy the requirements of this requirement. NMED agrees with the proposal to add the language providing that a maintenance plan required as part of a federal regulation will be sufficient to satisfy the requirements of Paragraph 1. This revised language is now included in Paragraph 2. NMED also agrees with the proposal to move the requirement to document taking a source out of service due to routine maintenance and unscheduled repairs from the monitoring provisions in Subsection C to the recordkeeping provisions in Subsection D.

Former Paragraph 2, Now Paragraph 3

GCA proposed to insert the term "inspected" into the first sentence of this paragraph. NMED agrees with this revision.

NMOGA and Kinder Morgan propose revisions to clarify what constitutes "manufacturer specifications." NMED agrees with this proposal and has included a reference to definition of that term in Subsection 20.2.50.112.

Former Paragraph 3, Now Paragraph 4

NMOGA and GCA propose revisions to clarify the following: deadlines for emissions testing requirements; types of portable analyzers that are authorized to test emissions; whether CO may be used as a surrogate to determine compliance with the NMNEHC emission standard;

whether an owner may use an alternative load calculation methodology to determine engine load; and load testing requirements. NMED agrees that these clarifications are appropriate and has proposed revisions to incorporate language clarifying each of the above matters.

NMED agrees with NMOGA's and Kinder Morgan's minor edits to add references to newly created paragraphs and add the federal regulatory citations for non-road engines.

NMED agrees with NMOGA's proposal to revise this paragraph to delete the requirement to scan the EMT prior to any monitoring event. The EMT scanning requirement has been removed throughout the rule, replaced by a requirement that owners and operators record a date and time stamp for each monitoring event.

<u>Subsection D – Recordkeeping Requirements</u>

NMOGA and Kinder Morgan propose to delete the reference to the EMT; clarify the reference to the term manufacturer specification; replace the term personnel with person; clarify that the records must be retained for a period of five years; add references to the federal definitions of non-road engines; add a citation to a new paragraph; and add a statement regarding allowing the use of an equivalent allowable ton per year reduction in addition to the annual operating hour reduction. NMED agrees that these revisions are appropriate.

NMOGA and Kinder Morgan propose two new requirements at paragraphs (5) and (6) to add a recordkeeping provision for owners and operators claiming an exemption from the requirements of this Subpart, and a record of a Department approved extension to the compliance deadlines in this Section. For the same reasons that NMED did not agree to add these new provisions in Subsection B, NMED does not agree to similarly modify the recordkeeping provisions in this Subsection.

The Department reviewed the information submitted by Kinder Morgan as part of their engine and turbine retrofit analyses submitted as Attachments F, G, H, I, J, K, and L to the direct testimony. Specifically, NMED used the information included in those attachments to determine the current emission rate of those units and to compare those rates to the revised emission limits proposed in NMED's redline version rule. The information reviewed is summarized in the following table:

Facility	Unit	Model (Year)	HP	Info from KMI Cost/ton Analyses	Estimated NO_X Emission Rate	Applicable Revised NO_X Limit
Caprock Compressor Station	A-01	GE Model M3712R Turbine (1957)	7040	66.2% reduction to reach the 50 ppmc NOx limit	148 ppmv	50 ppmv
	A-02	GE Model M3712R Turbine (1958)	7040	56% reduction to reach the 50 ppmc NOx limit	114 ppmv	50 ppmv
Rio Vista Compressor Station	A-01	Solar Model 10-T1202 Turbine (1998/2006)	1051	11% reduction to reach the 50 ppmc limit; based on highest ppm measured of identical unit at San Juan CS and the proposed NOx limit	63 ppmv	150 ppmv
	A-02	Solar Model 10-T1202 Turbine*	1051	11% reduction to reach the 50 ppmc limit; based on highest ppm measured of identical unit at San Juan CS and the proposed NOx limit	63 ppmv	150 ppmv
Monument Compressor Station	A-04	Cooper Bessemer GMV-10TF (1950)	1100	Currently at 1.95 lb/hr; 1.10 lb/hr = 0.5 g/hp-hr.	0.89 g/hp-hr	3.0 g/hp-hr
	A-05	Cooper Bessemer GMV-10TF (1953)	1100	Currently at 1.73 lb/hr; 1.10 lb/hr = 0.5 g/hp-hr.	0.79 g/hp-hr	3.0 g/hp-hr
Washington Ranch Storage	A-01	Cooper Bessemer 12Q155HC2 (1982)	4500	65.8% reduction to reach 0.5 gm/hp-hr; based on 3-yr average testing.	1.46 g/hp-hr	3.0 g/hp-hr

	B-02	Cooper Bessemer 12Q155HC2 (1982)	4500	41% reduction to reach 0.5 gm/hp-hr; based on 3-yr average testing.	0.85 g/hp-hr	3.0 g/hp-hr

The cost per ton analysis (Attachment J) identified one turbine at Rio Vista as a GE Model M3712R Turbine. However, Attachment G to Kinder Morgan's testimony, "Rio Vista Vendor Quote" is for two solar turbines, rated at 1,051 hp. We assume that based on the vendor quote, the second turbine is actually a Solar Turbine and both are rated at 1,051 hp and would be subject to a 150 ppm limit.

Based on this analysis, the engines and turbines at three out of the four facilities described by Kinder Morgan would be able to meet the revised NOx emission limits. The turbines at Caprock Compressor Station would be subject to a NOx limit of 50 ppmv and are achieving emission rates of 114 and 148 ppmv.

Since Caprock Compressor station would still be subject to the revised emission limits, NMED reviewed the cost estimates for the Caprock Compressor Station provided in Attachment I of Kinder Morgan's direct testimony. NMED found that Kinder Morgan inflated cost estimates by using unrepresentative baseline data and limiting emissions reductions to reach the proposed emission limit of 50 ppmv NO_X. Installation of Selective Catalytic Reduction (SCR) has a documented emissions reductions efficiency of 70-90%. The use of a three-year average of emissions is intended to provide a representative base emissions calculation for use in determining the cost effectiveness. This could be skewed low by use of unrepresentative years, where equipment is underutilized or not operational. For example, Unit A-01 did not appear to be utilized in 2018 and was only used for 2 hours in 2019, according to the Department's emission inventory submitted by Kinder Morgan under the Title V Permitting Program. When averaged with the 2,008 operating hours for the unit in 2020, this resulted in an average of 670 hours of use. This skews the base emissions low since this unit was grossly underutilized in 2018 and 2019. The same observation holds true for unit A-02 at the Kinder Morgan Caprock Compressor station. The unit was not utilized in 2018 consistent with 2019 and 2020 emissions estimates and operating hours.

To estimate the range of plausible cost estimates, NMED calculated a low- and high-end cost scenario using permitted allowable emissions and actual emissions for base case calculations to perform the analyses. Actual emissions were based on the emissions information submitted to the Department by Kinder Morgan under its Title V Operating Permit for the facility. The Department also utilized a 70% control efficiency as a conservative estimate of emissions reductions that may be realized by installing SCR. NMED's cost estimates for the two units located at the Caprock Compressor Station are provided in NMED Rebuttal Exhibit 5.

Unit A-01

For our high-end cost analysis, the Department used 34.4 tpy of NOX emissions in 2020, since this was the only year the equipment was actually used. We assume that this more accurately characterizes the normal use of the equipment. Based on a the current 148 ppmv emission rate and using a control efficiency of 70%, installation of SCR would result in an emission rate of approximately 44 ppmv and a reduction of 24.1 tpy of NO_X emissions. The cost effectiveness under this scenario would still result in spending approximately $25,000/ton but is only 31% of the cost estimate of approximately $80,000/ton of NO_X reduced provided by Kinder Morgan in their direct testimony.

To illustrate the range of cost effectiveness that could be used, NMED also considered a low-end cost effectiveness by evaluating the facility if it were to operate at its full permitted capacity. Based on the facility's latest Title V permit, this unit is allowed to emit 201 tpy of NO_X

at an emission rate of 45.9 lb./hr. and may operate continuously or 8,760 hrs./y. When this information is used for the cost effectiveness calculations, the cost per ton of pollutant drops to \$4,352/ton of NO_X reduced for unit A-01. A summary of the cost effectiveness calculations performed by the Department for this unit are provided in the table below.

Unit A-02

For our high-end cost analysis on unit A-02, the Department used the 2019-2020 average NO_X emissions of 62.68 tpy as supplied in the Department's Title V emissions inventory and an emission rate of 16.83 lb./hr as supplied in Kinder Morgan testimony. The year 2018 was excluded from the averaging calculation since the equipment was only used for 138 hrs. that year. Based on a the current 114 ppmv emission rate and using a control efficiency of 70%, installation of SCR would result in an emission rate of approximately 34 ppmv and a reduction of 43.9 tpy of NO_X emissions. The cost effectiveness under this scenario would still result in spending approximately \$20,000/ton of NO_X reduced, but is only 38% of the cost estimate of approximately \$54,000/ton of NO_X reduced provided by Kinder Morgan in their direct testimony.

For the low-end cost effectiveness analysis of the facility, NMED assumed the facility would operate at its full permitted capacity. Based on the facility's latest Title V permit, this unit is allowed to emit 172.1 tpy of NO_X at an emission rate of 39.3 lb./hr. and may operate continuously or 8,760 hrs./y. When this information is used for the cost effectiveness calculations, the cost per ton of pollutant drops to \$7,589/ton of NO_X reduced for this unit. A summary of the cost effectiveness calculations performed by the Department for this unit and the estimates provided by Kinder Morgan in their direct testimony at Attachment I are provided in the table below.

As demonstrated by NMED's cost calculations, an objective analysis of the cost effectiveness of installing emissions controls should be based on the expected use of the equipment, as well as the demonstrated control efficiencies of the technology considered. Additionally, facilities may consider other control measure options for compliance such as the installation of other technology, purchasing replacement equipment or converting to electric motors for compression where electric utility line power may be available.

NMED agrees with testimony provided by Kinder Morgan that installation of control equipment may not be cost effective in all cases. In response to this, the Department has proposed changes to provided additional flexibility for compliance through an alternative compliance plan, or through a petition process for the Department to grant a case-by-case alternative emission standard required by the proposed rule and as discussed in Section 113 Rebuttal Testimony.

Section 20.2.50.114 – Compressor Seals

NMOGA and Kinder Morgan propose that Section 20.2.50.114 be removed in its entirety. Alternatively, they propose revisions as outlined and addressed below. GCA and the Commercial Disposal Group ("CDG") propose to remove the EMT requirements in this Section, which the Department has agreed to as outlined in the rebuttal testimony on Section 20.2.50.112.

NMOGA noted that according to the ERG inventory documentation memo, total emissions from compressor seals (VOCs) is estimated at 13 tpy and only 0.006% of total VOC emissions and emissions would be only 6 tpy. NMED does not agree that the requirements addressing emissions from compressor seals should be removed from Part 50. Regarding NMOGA's assertion that compressor seals are an "inconsequential" source of ozone precursor emissions, NMED disagrees that emissions from these sources, particularly those in the gathering and boosting segment, are inconsequential. The data for those compressors are not required to be reported to the Department and compressor seals were not a separate item in the emissions inventory used for the modeling. In developing the federal standards for compressor seals in 40 CFR 60, Subpart OOOO, EPA estimated that the average VOC emission reduction from a centrifugal compressor with wet seals in the production segment would be 19.5 tpy, and for reciprocating compressors the reductions would be 4.2 tpy VOC for one in the gathering and boosting segment and 13.7 tpy VOC for one in the processing segment. *See* 76 Fed. Reg. 52738 (August 23, 2011), at p. 52761. EPA is still regulating compressor seal emissions in NSPS Subparts OOOO and OOOOa, except at well head compressors and in the transmission compression and storage segments.

NMED does agree to revise the language in Subsection B, Paragraph 3 to clarify that the requirement applies to compressors with wet seals. NMED also agrees with NMOGA's proposal to remove the requirement in Subsection B, Paragraph 4(b) that emissions be collected under negative pressure, and revise related provisions in Subsection C, Paragraph 3 and Subsection D, Paragraph 2(c)(ii), for the reasons provided on page 21 of NMOGA Appendix B.

NMED reviewed NMOGA's remaining proposed revisions throughout this Section. The revisions are all minor edits that provide clarification to the language, and do not alter the intent or meaning of the requirements. NMED agrees with all these proposed edits, with the exception of the insertion of "monitoring, testing, or inspection" where the term "monitoring" is used. NMED addressed that matter in edits to Section 20.2.50.112, as explained in the previous testimony.

With respect to transmission compressor stations handling pipeline quality natural gas, NMED agrees that these facilities should not be subject to the requirements of this Section.

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 agrees that it is appropriate to remove transmission compression stations that are handling pipeline quality natural gas from applicability of this Section.

Section 20.2.50.115 – Control Devices

NMOGA, Oxy USA, and GCA propose numerous revisions to Section 20.2.50.115. The Department agrees with many of these proposals and has made technical and clarifying edits to Section 20.2.50.115 in response. Revisions not agreed to by the Department are discussed in detail below.

<u>Subsection A - Applicability</u>

NMOGA proposes to insert "Closed Vent System" in the title of Section 20.2.50.115, and the title of Subsection A. NMED agrees with these clarifying revisions.

<u>Subsection B – General Requirements</u>

NMOGA proposes to add references in Paragraph 1 to other types of maintenance practices for compliance in addition to manufacturer specifications. NMED agrees with these revisions which address situations where manufacturer specifications may not be available or where experience dictates the need to adopt practices that differ from those specifications.

NMOGA proposes to revise language in Paragraph 2 clarifying that design requirements are to be based on the reasonably expected range of emissions being sent to the control device. NMED agrees with these revisions.

NMOGA proposes to remove the reference to the installation of the EMT, and the requirement to capture data using an EMT. The EMT tagging and scanning requirement has been removed throughout the proposed rule, and replaced by a requirement that owners and operators record a date and time stamp for each monitoring event.

NMOGA proposes revisions to Paragraph 3 clarifying the methods for inspections required under that Paragraph. NMED agrees with this proposal.

GCA proposes revisions to Paragraph 4 allowing a different inspection frequency schedule for control devices if developed by the owner or operator. NMED does not agree with this proposal. A monthly inspection of control devices to ensure their proper operation and to allow the owner or operator to identify any operational issues is a reasonable requirement. A different or less frequent inspection schedule would allow operational issues to persist unnoticed, resulting in emission releases that threaten human health and the environment. The current requirement provides consistency across all owners and operators, and ensures that all control devices are monitored on a consistent, ongoing basis.

NMOGA proposes to remove the requirement in Paragraph 5 to ensure that unburnt gas is not directly vented to the atmosphere. Based on NMOGA's comments, NMED has revised this provision to require that the owner or operator minimize venting of unburnt gas to the atmosphere.

NMOGA proposes to add language in Paragraph 5 providing that the control device or process should be designed to control the reasonably expected range of emissions, instead of all emissions from affected sources. NMED agrees to clarify that the control device or process should be designed to control the expected range of emissions instead of all emissions from affected sources. NMED does not agree to add the term "reasonably," as it is an unnecessary qualifier in this context. The expected range of emissions should be based on the conditions of the site and the affected source and "reasonably" adds uncertainty as to what should be considered reasonable.

NMOGA proposes to remove the requirement to have an engineer certify the closed vent system, and to allow an employee to conduct the certification. NMED does not agree with this proposal. The intent and purpose of this requirement is to establish a standardized set of requirements for the assessment of a closed vent system used to comply with this Part. Allowing any employee to certify the closed vent system creates an uncertain set of standards for an owner or operator to determine the effectiveness of the system and results in any employee being allowed to certify that the closed vent system has been designed properly, even if that employee has no knowledge regarding the engineering principles of a properly designed closed vent system. NMED does agree to revisions allowing an in-house engineer to certify this assessment, which the Department finds to be a reasonable authorization.

NMOGA proposes to replace "closed vent system" with "assessment" in the requirement Paragraph 5, Subparagraph c, and to make related revisions in the rest of that Subparagraph. NMED agrees with this proposal because it aligns with the terminology in the rest of Paragraph 5, and based on NMOGA's comment regarding this provision on page 24 of NMOGA Appendix B.

Subsection C – Requirements for Open Flares

NMOGA proposes to remove the provisions in Subsection C, Subparagraph (1)(b)(ii) requiring inspections of flares with manual ignition to ensure a flame is present upon initiating a flaring event. As the basis for this requirement, NMOGA claims that the New Mexico Oil Conservation Division's venting and flaring rule does not allow for manual flaring. NMED does not agree to remove this requirement. OCD's rule does not explicitly prohibit manual lit flares. That rule does require flares at non-stripper well facilities to be retrofitted with an automatic ignitor, continuous pilot, or technology that alerts the operator that the flare has malfunction no later than 18 months after May 25, 2021. However, for non-stripper well facilities, flares do not have to be retrofitted unless the flare is replaced, so existing manual lit flares are allowed under the OCD rule. Thus, there will be manual flares in operation to which Part 50 will apply. This requirement is practical and necessary for these types of flares, and appropriately requires owners and operators to simply ensure that a flame is present when the flare is operating and controlling a waste gas stream from a regulated source under this Section.

NMOGA proposes to remove the requirement in Paragraph 1, Subparagraph (c) that an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part, and replace it with a provision in requiring each existing flare (except those flares required to meet the requirements of Paragraph (D) of this Subsection) to be equipped with an automatic ignitor, continuous pilot, or technology that alerts the operator that the flare may have malfunctioned no later than two years after the effective date of Part 50. NMED agrees with these revisions to align with the requirements of OCD's venting and flaring regulations.

NMOGA proposes to remove the threshold of "10 barrels of oil per day or an average daily production of" from the requirement for existing flares to install a continuous flare, auto ignitor, or alarm system. NMED does not agree with this proposal. While OCD's regulations are aimed at reducing waste of natural gas as a product, NMED's proposed rule is aimed at reducing VOC emissions to meet public health-based air quality standards. An existing flare at an oil well is indicative that the well necessarily has a significant amount of emissions requiring combustion. The proposed language as written does not create conflicts between the requirements of the two agencies, as the provision also refers to natural gas throughput.

NMOGA proposes to add a requirement that only new flares are required to be monitored to ensure a continuous flame or presence of a flame during flaring if using an auto-ignitor. NMED does not agree with this proposal. NMED intended for both new and existing flares to be monitored to ensure the presence of a pilot flame or presence of a flame if using an auto-ignitor during flaring. Unlit flares contribute to significant excess emissions and are frequently discovered during inspections of oil and gas facilities. Ensuring the proper operation of flares is critical to ensuring the sources subject to this Section are controlled as intended. Without this requirement, flares will not control emissions as required in this Section potentially causing operational issues that result in significant releases of air emissions that could otherwise have been prevented.

NMED removed a redundant requirement in 20.2.50.115(C)(3)(f), which was essentially identical to the requirement in 20.2.50.115(C)(3)(a), and was therefore unnecessary.

<u>Subsection D – Requirements for enclosed combustion devices and thermal oxidizers</u>

NMOGA proposes to remove the requirement for at least quarterly monitoring of visible emissions from flares (Subsection C, Paragraph 2(c)) and enclosed combustion devices and thermal oxidizers ("EDC/TOs") (Subsection D, Paragraph, Paragraph 2(b)). NMED does not agree with this proposal. This provision establishes a reasonable monitoring requirement for visible emissions from flares and ECD/TOs. Visible emissions from flares and ECD/TOs are indicative of equipment that is malfunctioning and/or not properly combusting the waste gas emission stream. No visible emissions are expected when flares and ECD/TOs are operating as intended and, therefore, the requirement to check for visible emissions at least once every three months is reasonable and necessary to ensure the controls are operating as required and intended.

Subsection E – Requirements for vapor recovery units

NMOGA proposes to add change to the title of this subsection from "Vapor Recovery Unit" to "Vapor Recovery Capture Unit." NMED does not agree with this proposed revision for the reasons discussed previously in the rebuttal testimony on the definition of "Vapor Recovery Unit" in Section 20.2.50.7.

NMOGA proposes to add an authorization to exempt the requirement to install a redundant VRU if approved in a state permit. NMED agrees to this authorization for air permits issued by the effective date of this Part. This allow owners and operators to comply with existing air permits with respect to the VRU, which may not require redundant controls during VRU downtime.

NMOGA proposes to add an authorization 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. NMED agrees with this proposal.

NMOGA proposes to remove the requirements to record information related to the inspection and monitoring of VRUs, and to authorize the recordkeeping of shutting down and isolating a source in lieu of using a redundant VRU. NMED does not agree to remove the requirement to record information related to inspections or monitoring of the VRU, as this information is necessary to demonstrate compliance with the inspection and monitoring requirements. NMED agrees to add a requirement to keep records of the equipment shut down and isolation. NMED agrees to add the requirement to keep records regarding compliance with an air permit that was issued prior to the effective date of Part 50.

Oxy USA proposes revisions to Paragraph 1(b) allowing a five-year time frame for installation of redundant controls at locations that already have VRUs, citing supply chain issues. NMED agrees to extend the compliance deadline for this requirement to three years. The request for a five-year extension was not sufficiently supported in the testimony.

Section 20.2.50.116 – Equipment Leaks and Fugitive Emissions

NMOGA, Oxy USA, GCA, and Kinder Morgan proposed numerous revisions to Section 20.2.50.116. The Department agreed with many of these proposals and made technical and clarifying edits to Section 20.2.50.116 in response. Revisions that the Department does not agree to support are discussed in detail below.

<u>Subsection A – Applicability</u>

NMOGA and Kinder Morgan propose to add a provision that would allow compliance with equipment leak and fugitive monitoring required under NSPS Subparts OOOO and OOOOa to be used to satisfy the requirements of Part 50. NMED does not agree that facilities complying with other federal leak detection and repair requirements should be considered in compliance with the requirements of this Part. Those requirements, while important to reducing emissions, have not been sufficient to secure enough reductions from leaks to address the rising ozone concentrations in the State. The AVO and leak inspection frequency requirements proposed in this Part are reasonable and appropriate requirements to ensure owners and operators are monitoring their operations on a more frequent basis and are necessary to ensure continued reductions of emissions from leaking equipment across the industry.

NMOGA proposes revisions to limit the applicability of this Section to components that are gas vapor or light liquid components that contact process fluid that is at least 10% VOC by weight, and exempt components in water and/or air service. NMED agrees to exempt components in water and/or air service but does not agree to exempt components that contact process fluid that is less than 10% VOC by weight. NMOGA did not provide any testimony identifying the number of sources this change would potentially exempt, and therefore the Department is unable to determine the potential impacts of such an exemption.

NMOGA proposes revisions exempting facilities that process only coal bed methane. NMED agrees to revise the LDAR monitoring frequency to annually for any facility producing or processing exclusively coal bed methane. Similarly, NMED has revised the LDAR monitoring frequency to annually for transmission compressor stations.

<u>Subsection C – Monitoring Requirements</u>

NMOGA and Kinder Morgan propose to remove the term "Default" from the title of this Subsection. NMED does not agree with this proposal. The rule establishes one set of default monitoring requirements unless an alternative fugitive emission monitoring plan has been approved by the Department. The rule provides the option for owners or operators to request the use of an alternative monitoring plan, as provided in Subsection D. The term "default" is required to distinguish between the two options: the default monitoring requirements under Subsection C, and the use of an approved alternative plan under Subsection D. Failure to identify the default requirements would confuse the difference between the two options. Unless the

Department has approved the use of an alternative, owners and operators must comply with the requirements of Subsection C.

NMOGA and Kinder Morgan propose language in Paragraphs 1 and 2 that would limit AVO inspections to only well sites and tank batteries based on natural gas production and remove reference to average daily production or throughput of oil per day. NMED does not agree with these proposals. NMED intended that all facilities subject to Part 50, including those that are primarily oil producing facilities that may have relatively low natural gas production, conduct an AVO inspection on either a weekly basis for larger producing or processing facilities, or a monthly basis for smaller producing or processing facilities. 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.

NMOGA proposes to add “or average daily throughput” to Paragraph 1 to clarify that the requirement is applicable to facilities that process amounts above the specified threshold, and proposes to add the same language to Paragraph 2 to clarify that requirement is applicable to facilities that process amounts at or below the specified threshold. NMED agrees with these clarifying revisions.

NMOGA proposes to add language to Subparagraph 1(a) to clarify that a visual inspection is an external inspection. NMED agrees with this proposal.

NMOGA proposes to remove the language in Subparagraph 1(d) that a positive detection during an AVO inspection shall be considered a leak. NMED agrees with this proposal.

NMOGA proposes to remove the requirement in Subparagraph 1(e) and refer instead to the requirements of Subsection E, which require tagging and repairs.

GCA proposes to change the required timeframe in Subparagraph 1(e) for tagging and reporting a leak from three calendar days to three business days. NMED agrees with this proposal and has made in Subparagraph 1(d).

Oxy USA proposes to phase in the leak survey requirements for facilities constructed prior to the effective date of Part 50. In response to Oxy USA's testimony, NMED is proposing revisions that would give existing well sites and tank batteries two years to comply with the leak survey requirements.

Oxy USA proposes language in a new Paragraph 4 that would exempt facilities, such as satellite facilities, injection facilities, inactive facilities, and wellhead-only facilities that either include very few pieces of equipment that could potentially result in emissions due to leaks or are inactive and therefore cannot increase emissions because they are not handling any material that could leak. NMED does not agree with this proposal but has added language to the rule to address the comment. NMED added a new LDAR frequency threshold for facilities with a PTE less than two tons per year VOC. Those facilities are now required to conduct a one-time survey, which is consistent with Colorado's Reg. 7. NMED also added a requirement that an owner or operator shall conduct a leak survey upon request by the department, which would allow the department to request a survey if warranted. The term "satellite facility" is undefined, and it is unclear what types of facilities or equipment Oxy intended to include within this term. Saltwater disposal facilities, including injection facilities, are not subject to Part 50 so there is no requirement to survey those facilities. Inactive and well-head only facilities are required to conduct a one-time survey. This one-time survey is a reasonable requirement for these types of facilities, as it will detect emissions that may be associated with improper shut in, decommissioning, or plugging.

NMOGA proposes to increase the applicability thresholds for well sites and tank battery facilities in Subparagraph 3(a) as follows: for annual LDAR, from two tons per year to ten tons per year VOC; for semi-annual LDAR, from two to five to ten to twenty-five; and for quarterly LDAR, from five to twenty-five. NMED does not agree to the proposal but has revised the LDAR frequency for well sites and tank batteries to more closely align with the LDAR provisions in Colorado's Reg. 7. The new LDAR requirements for well sites and tank batteries are a one-time LDAR survey for facilities that emit less than two tpy VOC; annual LDAR surveys for facilities that emit between two and six tpy VOC; semi-annually for facilities that emit between six and twelve tpy VOC; and quarterly at facilities that emit greater than twelve tpy VOC. NMED will consider further evidence and provide a different recommendation to the Board if that evidence indicates that these thresholds are not appropriate.

NMOGA and Kinder Morgan propose to decrease the LDAR frequencies for gathering and boosting, gas plants, and compressor stations in Subparagraph (3)(b) from quarterly to semi-annual for sites with a PTE of VOC emissions less than 25 tons per year, and from monthly to quarterly for sites with a PTE of VOC emissions greater than 25 tons per year. NMED agrees with these proposals based on the direct testimony submitted by NMOGA and Kinder Morgan, but will consider further evidence and provide a different recommendation if that evidence indicates that these increased thresholds are not appropriate.

NMOGA proposes to add language to Subparagraph 4(a) specifying that calibrations must be done according to the instrument manufacturer. NMED agrees with this proposal.

NMOGA proposes to remove the requirement in Subparagraph 4(b) to calibrate with zero air and a mixture of methane and hexane. NMED agrees with this proposal because EPA Method 21 already includes this requirement, rendering the language unnecessary.

NMOGA proposes to add language in a new Paragraph 6 providing that leaks detected are not subject to enforcement action unless the owner fails to perform the required repairs within the specified timeframes specified in Subsection E, or keep records in accordance with Subsection F. NMED does not agree with this proposal. LDAR inspections provide important information to owners and operators regarding the condition of sources and the overall state of operations at a facility. There may be instances where the Department discovers egregious violations from leaking components that present an imminent and substantial danger to human health or 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. The Board should not categorically limit the Department's enforcement authority in the manner proposed. Doing so would unreasonably hinder the Department's ability to enforce on violations and would conflict with the Department's existing regulatory and statutory authority to take enforcement action for violations of the AQCA and Part 50.

NMOGA proposes to remove requirements in existing Paragraph 6(a) specifying when components are considered difficult to monitor. NMED agrees with this proposal.

<u>Subsection D – Alternative equipment leak monitoring plan</u>

NMOGA proposes revisions to Subparagraph 1(b) changing the timeframe in which an owner operator must correct and disclose a violation of an alternative monitoring plan from within 15 days of "identifying" the violation to within 15 days of "verifying" the violation. NMED does not agree with this proposal. Once a violation has been identified, it does not need to go through a verification process in order for it be considered a violation. The owner or operator may choose to voluntarily verify the violation, but that verification is not necessary to correct the violation, which would result in delayed repairs and increased emissions, and should not be the action that triggers correction of the violation or notification to the Department.

Subsection E – Repair Requirements

NMOGA proposes clarifying language regarding the need to tag components that are repaired at the time a leak is discovered in Paragraph 1, and revisions to the repair deadlines in Paragraph 2 and 4. NMED agrees with these proposals.

NMOGA proposes to add a requirement in new Paragraph 5 that if a leak cannot be repaired due to personnel or parts delay, the repair can be delayed and must be repaired within 15 days of resolution of the shortage. NMED agrees in part with this proposal and has revised the paragraph to allow for delayed repairs due to parts shortages, but not personnel shortages. Owners and operators should not be authorized to delay repairs due to personnel shortages, which may be caused by different factors, including a company's chronic understaffing of compliance experts needed to comply with this Part.

Cost Analysis

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. As discussed in the direct testimony at NMED Exhibit 32, the analyses were based largely on the U.S. EPA's Control Techniques Guidelines for the Oil and Natural Gas Industry. *See* NMED Exhibit 24 ("2016 CTG"). NMOGA argues 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 claims 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 cannot evaluate the validity or representativeness of the alternative model plants mentioned by NMOGA, because NMOGA does 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.

NMOGA also argues 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,"[1] 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. 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.

NMOGA also argues that 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, supported less frequent surveys at higher emission thresholds for well sites and tank batteries. NMED disagrees that these data should be used to justify less frequent surveys and higher emissions thresholds. NSPS

[1] EPA Docket Number EPA-HQ-OAR-2015-0216.

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. 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.

NMOGA also cites 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." However, NMOGA does 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.

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 concludes 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 fails 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 does 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 relies 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 is 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 does 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.

NMED has reviewed the two cited papers and agrees that they present useful data on leak frequencies and emission rates. However, other commenters have 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. NMED has concluded that it is beyond the scope of this rulemaking for the Board 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 NMED 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.

NMOGA argues 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 proposes 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.

NMED is not willing to propose that the Board allow compliance with the LDAR requirements in NSPS subparts OOOO or OOOOa ***as revised*** to constitute compliance with Section 20.2.50.116 because 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 will give New Mexico no certainty over the future regulatory requirements limiting VOC emissions from equipment leaks at oil and gas facilities in the State. It is worth noting, for example, that 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.

NMED acknowledges that it is difficult to accurately estimate the cost effectiveness of an LDAR program without data that are specific to a particular type of facility. The LDAR provisions for gas processing plants in the 2016 CTG and NSPS Subparts OOOO and OOOOa recommend implementing, or require complying with the requirements of, the LDAR program in 40 CFR part 60, subpart VVa (NSPS for Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006). These are the same requirements promulgated in the Compliance Assurance Monitoring Rule (40 C.F.R. Part 65, Subpart F, Equipment Leaks) and are not specific to natural gas processing plants.

Given the uncertainties in estimating the cost effectiveness of an LDAR program for oil and gas operations in New Mexico, NMED is proposing changes to the LDAR inspection frequencies and emission thresholds to align with Colorado Reg. 7, and accepting NMOGA's proposal regarding gas processing plants and gathering and boosting stations. Specifically, components at well production facilities and tank batteries would be subject to Method 21 instrument monitoring or OGI monitoring one time if the facility has a PTE less than 2 tpy VOC; annually if the facility has a PTE equal to or greater than 2 tpy VOC and less than 6 tpy of VOC; semiannually if the PTE is equal to or greater than 6 tpy, but less than 12 tpy; and quarterly if the PTE is equal to or greater than 12 tpy. Under NMOGA's recommended changes, all components at gathering and boosting sites and gas processing plants would be subject to Method 21 instrument monitoring or OGI monitoring semiannually if the facility has a PTE equal to or less than 25 tpy of VOC, and quarterly if the PTE is equal to or greater than 25 tpy. While NMED does not believe the revisions will significantly impact the cost estimates for the LDAR provisions, NMED is updating the emission reductions and cost estimate spreadsheet to reflect the revised frequencies and will submit the updated spreadsheet prior to the hearing to allow time for the other parties to review. NMED is also proposing revisions in Subsection C, Paragraph 3(d) to require annual Method 21 instrument monitoring or OGI monitoring at any facility producing or processing exclusively coal bed methane and at transmission compressor stations.

While NMED is proposing to revise the monitoring frequencies, NMED will consider further testimony provided by any of the parties that would support a recommendation that the Board adopt different frequencies and/or cost effectiveness estimates.

Section 20.2.50.117 – Natural Gas Well Liquid Unloading

NMOGA and IPANM proposed a number of revisions to Section 20.2.50.117. The Department agrees with many of these proposals and has made technical and clarifying revisions to Section 20.2.50.117 in response. Edits not agreed to by the Department are discussed in detail below.

<u>Subsection A – Applicability</u>

NMOGA and IPANM propose to add the term “Manual” to the applicability provisions and throughout the rule where the term “liquid unloading” is cited. NMED does not agree with this proposal as it would restrict the type of unloading events covered under this Section. NMED intended to regulate both manual and automated liquid unloading events that result in venting of natural gas.

NMOGA and IPANM propose to delete down hole maintenance events as they are covered under Section 20.2.50.124. NMED agrees with this proposal.

NMOGA and IPANM propose to add a clarification that liquid unloading events that do not result in the venting of natural gas are not subject to this Section. NMED agrees with this proposal.

IPANM proposes to add language that this Section only applies in areas of the state specified in 20.2.50.2. NMED disagrees with this proposal. The proposed language is 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.

IPANM 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. NMED rejects this language as circular and redundant.

NMOGA proposes to add a requirement that unloading events are subject to the requirements of Paragraph 3 of Subsection B within two years of the effective date of Part 50. NMOGA did not provide testimony indicating why two years is necessary to comply, but NMED acknowledges that a one-year compliance deadline is reasonable given that operators may have multiple sites needing to be retrofitted to meet the requirements of this Part.

Subsection B – Emission Standards

NMOGA proposes to add a requirement that unloading events are subject to the requirements of Paragraph 2 within two years of the effective date of this Part. NMED does not agree with this proposal. NMOGA provides no testimony or rationale for this proposal. NMED finds that these requirements can and should be met by the effective date of this Part. The requirements are simply to follow best management practices, which does not require the installation of new equipment or emission reduction devices. To the extent these requirements are not already being followed, they can easily be implemented through employee training.

NMOGA proposes to add language that would allow for the use of the methods listed in this Part and other undefined methods. The methods outlined are a selection of the technically feasible methods identified in the MAP Technical Report (NMED Exhibit 10), NMOGA's Methane Mitigation Roadmap (NMED Rebuttal Exhibit 7), and the US EPA's Oil and Natural Gas Sector Liquids Unloading Processes (NMED Rebuttal Exhibit 8). NMED has revised Paragraph 3 of Subsection B 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.

NMOGA proposes to add language throughout this Section to clarify that the requirements apply to the venting of natural gas associated with unloading events. NMED agrees with this proposal.

NMOGA proposes revisions to Paragraph 3 allowing the use of other unspecified methodologies to reduce emissions, and to include authorization to use an automated control system. NMED agrees with these proposals because they provide flexibility.

IPANM proposes to remove Paragraph 3 in its entirety. NMED rejects this proposal. The issues raised in IPANM's testimony are addressed by the new revisions adding flexibility in the types methodologies that can be used.

<u>Subsection C - Monitoring</u>

NMOGA and IPANM propose to delete the requirement to install an EMT. NMED has proposed revisions throughout the rule addressing this issue, as explained previously in this rebuttal testimony.

NMOGA proposes to delete the requirement to monitor the flow rate of the vented gas to the extent feasible. NMED does not agree with this proposal. NMED has already proposed language providing flexibility regarding this requirement and finds that 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.

<u>Subsection D – Recordkeeping Requirements</u>

IPANM proposes 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. NMED does not agree with this proposal. 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.

NMOGA proposes to add clarifying language regarding the calculation of vented natural gas. NMED agrees with this proposal.

Section 20.2.50.118 – Glycol Dehydrators

<u>Subsection A - Applicability</u>

NMOGA proposes to modify Subsection A to limit applicability of Section 20.2.50.118 to those dehydrators with an actual annual average flowrate of greater than 3 MMscfd throughput. The throughput threshold proposed by NMOGA is an exemption threshold present in the federal NESHAP regulations for emissions from glycol dehydrators at 40 CFR Part 63, Subpart HH. As explained in other parts of this rebuttal testimony, 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 rejects NMOGA's proposed exemption threshold because VOC emissions from dehydrators vary primarily by composition of the gas, and less by throughput amount. Thus, 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.

<u>Subsection B – Emissions Standards</u>

NMOGA proposes revisions to include their proposed concept of a "vapor recovery control unit," as distinguished from a "vapor control unit" in the provisions of Subsection B, Paragraph 3. NMED disagrees with this proposal for the reasons outlined previously in the rebuttal testimony regarding NMOGA's proposed definition of the term "vapor recovery control unit" in Section 20.2.50.7.

NMOGA proposes additional language in Paragraph 3(c) clarifying that the requirement not to vent emissions applies during normal operations. NMED agrees with the proposed revisions.

NMOGA proposes to remove the term “uncontrolled” from the language in Paragraph 5 of Subsection B, such that the offramp from applicability of this Section would apply to actual emissions. NMED agrees with this proposal for the reasons set forth in NMOGA Appendix B, page 39.

<u>Subsection C – Monitoring Requirements</u>

NMOGA proposes revisions that would allow use of a representative gas analysis in the emissions calculations in lieu of unit-specific inlet analyses. NMED disagrees with this 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.

<u>Subsection D – Recordkeeping Requirements</u>

NMOGA proposes revisions to Paragraph 1(g) regarding manufacturer recommendations. This issue has been addressed by NMED’s proposed revisions in this Paragraph, and in Section 20.2.50.112 regarding the term “manufacturer specifications” as used throughout Part 50.

Section 20.2.50.119 – Heaters

<u>Response to NMOGA’s Proposals</u>

NMOGA proposes to modify the CO emission limits for new and existing heaters from 300 ppmv (for existing units) and 130 ppmv (for new units) to 400 ppmv for all units. NMOGA asserts that these changes are required to “establish a reasonable emission limit,” explaining as follows:

> As combustion temperature is increased to lower CO emissions, NOx emissions increase. Conversely as combustion temperature is decreased to lower NOx emissions, CO emissions increase. To avoid continual adjustment of temperature to control both NOx and CO, utilizing a CO well-established emission limit allows for effective control of NOx while also providing a protective limit for CO emissions. Limits from other comparative regulations ((SCAQMD Rule 1146 & 30 TAC 117) have set a standard CO limit at 400 ppmv @ 3% O2.

Appendix B to NMOGA NOI, at p. 39.

NMED agrees that there is a relationship between NOx and CO emissions and that regulatory programs in California and Texas currently require CO emissions to remain below 400 ppmv in certain ozone nonattainment areas. Based on NMOGA's comment, NMED has proposed to revise the CO limit for new and existing heaters to 400 ppmv.

NMOGA also proposes revisions to the testing requirements to provide for testing only at highest achievable load, and removing the option to test within ten percent of one hundred percent peak. The stated reason for this change is that "heater tests should only be required to verify their emission limits at the highest achievable capacity during the test." NMOGA Appendix B at p. 41. The rule currently allows for testing at highest achievable load ***or*** within ten percent of one hundred percent peak load. Therefore, the suggested language does not materially change the testing requirement because heater tests already have the option to verify emissions only at the highest achievable capacity. NMED has not made any revisions as a result of this comment.

NMOGA also proposes that the timeline for existing heaters to come into compliance with this Section be extended from one to three years on the basis that "more time will be needed for the large heaters at processing plants to design the change, budget for the upgraded equipment, procure the equipment and schedule the equipment downtime to minimize plant or upstream flaring events." NMED agrees that an extension of the compliance deadline for existing heaters from one to three years is warranted.

Response to IPANM's Proposals

IPANM proposes to raise the applicability threshold for heaters from 10 MMBtu/hr to 50 MMBtu/hr based on higher estimated control costs for 10 MMBtu/hr 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 are taken from the EPA 1993 ACT document at NMED Exhibit 53, and are based on a 17 MMBtu/hr heater, which is the smallest heater size for which cost data is available. It may not be appropriate to use these costs for a 10 MMBtu/hr heater, which is the smallest size heater size subject to the rule. 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 ($2019), 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 has agreed 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. Based on this higher threshold, NMED calculates an overall cost effectiveness of $3,010/ton NOx. *See* NMED Rebuttal Exhibit 9 – ERG – Updated Heaters Reductions and Costs NO2 Spreadsheet. A comparison of the number of affected units, emissions reduction, and cost effectiveness based on a 10 MMBtu/hr applicability threshold and a 20 MMBtu/hr applicability threshold is shown in the table below.

Size Cutoff (MMBtu/hr)	Number of affected units	Emissions Reduction (tpy NOx)	Cost Effectiveness ($/ton NOx)
10	82	216	$3,162
20	58	176	$3,010

Section 20.2.50.120 – Hydrocarbon Liquid Transfers

<u>Subsection A – Applicability</u>

NMOGA proposes a compliance deadline of three years from the effective date of Part 50 for all operations subject to Section 20.2.50.120. Oxy USA proposes revisions to extend the compliance deadline from one to two years from the effective date of Part 50 for existing hydrocarbon liquid transfer operations. NMED agrees with Oxy USA's proposal and has proposed corresponding revisions. NMOGA did not provide justification for a three-year extension for all sources, but NMED acknowledges that additional time may be necessary for existing operations to comply with this Section, and agrees with Oxy USA that two years is reasonable.

NMOGA proposes language providing an offramp from the requirements of this Section for facilities that are connected to an oil pipeline routinely used for hydrocarbon liquid transfers and for facilities that load out hydrocarbon liquids to trucks fewer than 13 times per year. NMED agrees with these revisions for the reasons provided in NMOGA Appendix B, page 41.

CDG proposes language that when transferring a hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC, no requirements under 20.2.50.120 NMAC apply. NMED agrees with this revision.

Subsection B – Emission Standards

NMOGA proposes minor clarifying revisions throughout this Subsection. NMED agrees with these revisions.

NMOGA proposes to revise the percent control requirement in Paragraph 1 from 98% to 95%. NMED agrees with these revisions for the reasons articulated previously in this rebuttal testimony.

NMOGA proposes revisions to Paragraph 2 clarifying that vapors may be routed to a manifolded tank battery. NMED agrees with this proposal for the reasons provided in NMOGA Appendix B, page 42.

NMOGA proposes revisions to remove the requirement in Paragraph 2(c) to maintain equipment in a leak free condition and replace with the requirement to inspect for leaks. NMED does not agree with this proposal. It is not sufficient that connector pipes and couplers simply be inspected without also maintaining the equipment in a leak free condition. The inspection is appropriate to monitor those connections and equipment, and it is appropriate for the owner, operator, or authorized representative to identify leaks such that the equipment is maintained in a leak free condition.

NMOGA proposes to remove the requirement for bottom or submerged loading in Paragraph 3. NMED agrees with this proposal for the reasons provided in NMOGA Appendix B, page 42.

NMOGA proposes remove the requirement in Paragraph 6 that liquid leaks must be disposed in a manner that prevents leaks, and replace with a requirement to minimize leaks. NMED agrees with this proposal for the reasons provided in NMOGA Appendix B, page 42.

Subsection C – Monitoring Requirements

NMOGA proposes revisions to Paragraph 1 allowing an authorized representative of the owner or operator may conduct the required monitoring. NMED agrees with this proposal.

NMOGA proposes to revise the language requiring equipment to be inspected during a transfer operation to require monthly inspections at manned locations and semi-annual inspections at unmanned locations. NMED has proposed revisions to reduce the inspection frequency of unmanned sites and require that at least once per calendar year, the inspection shall occur during a transfer operation. This Section is aimed at regulating transfer activities, not just the equipment associated with those activities. Thus, at least some inspections must occur during actual transfer operations in order to better inform operators of any leaks that occur during those operations.

NMOGA proposes revisions to Paragraph 1 to allow for measures for leak mitigation during transfer operations where permanent repairs cannot be completed prior to the next operation. NMED agrees with this proposal for the reasons provided in NMOGA Appendix B, page 43.

<u>Subsection D – Recordkeeping Requirements</u>

NMOGA proposes to remove the requirement in Paragraph 1 to maintain a record of the location of the storage vessel and any control device used. NMED does not agree with this proposal. 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 agrees to change the language requiring a record of the location of the storage vessel to requiring a record of the location of the facility.

NMOGA proposes revisions to Paragraph 2 clarifying that inspection records for vapor tightness are only required for equipment owned by the owner or operator. NMED agrees with this proposal.

NMOGA proposes to remove the requirement in Paragraph 3 to maintain a record of the calculation of the individual loading emissions and total annual company-wide emissions. NMED does not agree with this revision. NMOGA provides no basis for this request. NMED's direct testimony at NMED Exhibit 32 provided the data regarding liquid transfers, and the estimated emissions reductions and costs for the proposed requirements. These records required 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. *See* NMED Exhibit 32 at p. 113-116.

Section 20.2.50.121 – Pig Launching and Receiving

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.

As explained in NMED's direct testimony, the provisions of Section 20.2.50.121 are based on Pennsylvania GP-5 and GP-5A, and Ohio's General Permits. See NMED Exhibit 32 at p. 119-120. Colorado also recently proposed regulations targeting emissions from pigging operations. Thus, other states have found it worthwhile and appropriate to regulate these operations. NMED's direct testimony explains 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. *Id.* at p. 120. We also know that the universe of affected operations is larger than what our data shows, and therefore the emissions reductions will be greater than what the modeling shows. NMED therefore believes that some level of regulation for pigging operations is warranted, and does not agree that the Board should entirely remove this provision from proposed Part 50. However, NMED does agree to significantly revise this Section to incorporate most of the changes proposed by the industry parties, as discussed below.

<u>Subsection A - Applicability</u>

NMOGA, Kinder Morgan, and CDG propose revisions that would make the requirements in Section 20.2.50.121 applicable to individual pig launchers and receivers with a PTE greater than or equal to 1 tpy VOC. NMOGA also proposes that the requirements only apply to pig launchers and receivers located within the property boundary of listed facilities. CDG further requests revisions specifying that the affected pig launchers and receivers within the property boundary of the listed facilities must also be under common ownership and control with those facilities. NMED agrees with these proposals for the reasons outlined in NMOGA Appendix B, page 44, the direct testimony of CDG witness Greg Jones, and the direct testimony of Kinder Morgan witness Leslie Nolting.

<u>Subsection B – Emissions Standards</u>

NMOGA and CDG proposes revisions to Paragraph 1 to require a capture and control efficiency of 95% instead of 98%. NMED has agreed to these revisions throughout Part 50, as discussed previously.

NMOGA proposes to extend the compliance deadline in Paragraph 1 to three years from the effective date of Part 50. No testimony is provided to justify this extended timeline. NMED acknowledges that a reasonable timeline is appropriate to come into compliance, and therefore agrees to revise the condition to require compliance within two years of the effective date of Part 50.

NMOGA and Kinder Morgan propose to revise Subsection B, Paragraph 2(a) and (b) to require operators to minimize emissions, as opposed to prevent them, recognizing that fugitive emissions that are impractical to prevent will occur. NMED agrees with these revisions.

NMOGA proposes revisions to Paragraph 3 to align with the revisions to the Subsection A. NMED agrees with this proposal.

Subsection C – Monitoring Requirements

NMOGA and Kinder Morgan propose several revisions to the requirements in this Subsection 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. NMED agrees with these proposed revisions for the reasons set forth in NMOGA Appendix B at page 45, and the direct testimony of Kinder Morgan witness Leslie Nolting.

NMOGA proposes revisions to Paragraph 3 that would exempt portable control equipment from the requirements of this Section. NMOGA does not provide any justification for this proposal. NMED does not agree with this proposal in in NMOGA's testimony or its redline. The requirements in Section 20.2.50.121 are appropriate for portable as well as permanent control devices because they ensure 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.

Subsection D – Recordkeeping Requirements

NMOGA proposes revisions to Paragraph 1 and its subparagraphs to align the language with revisions to other parts of this Section. NMED agrees with these revisions.

Section 20.2.50.122 – Pneumatic Controllers and Pumps

The Department reviewed the extensive comments and proposed revisions to Section 20.2.50.122 in the direct testimony submitted by NMOGA, IPANM, Oxy USA, GCA, CDG, and Kinder Morgan (collectively, "Industry Parties"), and EDF, CCP, and NAVAED (collectively "eNGO Parties"). These comments and revisions are far too numerous and pervasive to address one by one. A summary of the proposals is provided below. On a broader level, much of the testimony from the Industry Parties proposes adoption of the regulatory approach to pneumatic controllers adopted in February of 2021 by Colorado as part of its Regulation 7. For the reasons discussed below, the Department does not believe the Colorado approach is appropriate for New Mexico. While the Industry Parties have made general statements about the benefits and workability of the Colorado approach, they have not described why or demonstrated how NMED's proposal is unworkable or inappropriate for New Mexico, nor does that conclusion necessarily follow from the comments they have provided.

For their part, the eNGO Parties do not oppose the overall regulatory approach proposed by the Department. They do propose certain revisions that would impose shorter 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.

While the Department is proposing several revisions to address concerns raised by the other parties, as discussed below, the overall concept and structure for pneumatic controllers as originally proposed in the Petition for Rulemaking is being retained.

Response to Industry Parties' General Proposal to Adopt Colorado Approach

NMED does not agree with the Industry Parties' proposal to adopt the approach taken in Colorado Reg. 7, Part D, Section III.C.4., which regulates pneumatic controllers on the basis of total historic liquids production rather than controller counts, as specified in Tables 1 and 2 in Section 20.2.50.122. It is important to note that 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 that the Industry

Parties seek to mirror in proposed Part 50 were developed based on the pre-existing regulatory requirements in that state and in the context of emissions reductions already 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 has 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 accomplishes 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 has 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. NMED finds that its 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.

Summary of Specific Proposals

Industry Parties

In his direct testimony, NMOGA witness Mr. John Smitherman argues that NMOGA Section 20.2.50.122 should mimic Colorado's rule because it "will speed up emissions reduction and make enforcement more transparent." He goes on to explain as follows:

> This plan will speed emissions reduction because it will focus activity on the largest producing sites first. The biggest producing sites are a good place to start because there are typically many pneumatic devices at these sites and the sites are more likely to have utility electric power so compressed air systems can be more easily installed to drive the devices. This also makes sense for operators since these sites are the most cost effective to transition to non-emitting devices (even if utility power is not available).

Smitherman Direct at p. 29. NMED's proposal already allows for the biggest producing sites to be retrofitted first, resulting in faster emissions reductions, and the proposal already allows operators to prioritize sites with utility electric power, so there is no material difference between the two proposals on these points. In fact, the only difference between the Colorado rule and the Department's proposal on these points is 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.

Mr. Smitherman next praises the Colorado approach of basing the replacement schedule for pneumatic controls on a percentage of production at well production facilities "will be transparent since production is already reported to OCD and will be a public record and, perhaps most helpful, the plan will result in entire sites being either non-emitting or emitting which should make monitoring and enforcement much easier for NMED." Smitherman Direct at p. 29. NMED does not agree that basing the requirements on a percentage of production basis will necessarily improve transparency with respect to this Section. The Department can at any time require an owner or operator to produce a total controller count, which provides the same level of transparency as a well production record. NMED's proposal does require operators to track information and report that data to the Department. But the fact that the Department's proposal addresses pneumatics on a controller count basis does not necessarily make the requirement more difficult to monitor or enforce. NMOGA does not provide testimony explaining exactly why this would be so, other than that production is already reported to OCD. The Department notes that OCD regulates oil and gas on a different basis and under different authorities than NMED, and the data collection parameters of the two agencies do not always align, nor is it necessary or appropriate that they do. These facts alone do not justify changing the entire approach which is otherwise workable.

In the comments in the redline attached to its direct testimony, NMOGA asserts 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.

NMED disagrees with 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. Instead, NMED has appropriately relied upon the well-established emission factors accepted by other state agencies and the U.S. EPA, and required for federal greenhouse gas reporting to estimate the emission reductions and costs of this proposed rule.

In its redline attached to its direct testimony, NMOGA states that "planning at the facility level allows for orderly replacement rather than ad hoc replacement, which is more certain to achieve the desired reductions and will reduce costs." NMOGA Appendix B at p. 49. NMED agrees that planning at the facility level allows for orderly replacement and will reduce costs. The current proposal already provides for this exact type of flexibility.

Oxy USA proposes to exempt pneumatic controllers used for artificial lift from the requirements of this Section. NMED does not agree with this proposal. 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, as addressed above, that allow owners and operators to prioritize which controllers are retrofitted or replaced first.

IPANM proposes to exempt well sites or tank batteries with three or fewer controllers. NMED does not agree with this proposal as it 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 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.

GCA proposes to classify intermittent pneumatic controllers as “low-emitting” or “non-emitting controllers” and proposes to include their use in meeting the non-emitting controller requirements under this Part. *See* Carr Direct at p. 4. NMED does not agree to adopt this classification for meeting the requirements of this Section. In their comments, GCA cites to a manufacturer specification sheet for liquid level switches that have a low emission rate. NMED does not dispute the stated emission rates for these controllers, but disagrees that it is appropriate to consider all existing or future intermittent controllers as low-emitting based on a single manufacturer specification sheet. GCA also cites to an EPA report as the basis for considering intermittent controllers to be low-emitting controllers. However, that report provides details on multiple studies that have been conducted to determine the emissions from different types of pneumatic controllers, and the data in those reports do not support GCA’s claim. For instance, one study reviewed in the report and included as an exhibit to the Department’s direct testimony, states that “[b]ased on the [EPA] Subpart W data and the assumptions above, the study used the following emission factors for each of the controllers: 320 Mcf/yr/device for high bleed, 120 Mcf/yr/device for non-dump intermittent, 20 Mcf/yr/device for dump intermittent and 11 Mcf/yr/device for low bleed pneumatic controllers." NMED Exhibit 091 at p 27. The report indicates that the emission rate for both types of intermittent devices is either two or ten times greater than the emission rate for low bleed controllers, and thus NMED does not agree that intermittent controllers should be considered either a low bleed controller or equivalent to a zero-bleed controller for the purposes of this Section.

eNGO Parties

The eNGO Parties proposed that all sites 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 comply with this Section within six months of the effective date of Part 50; that the other existing pneumatic controllers meet more aggressive deadlines with a final deadline of May 1, 2025; and that Table 1 and Table 2 be combined to require all types of facilities to meet new percentages of non-emitting controllers.

At this time, NMED does not agree to make revisions to the proposed compliance timeframes or to change the percentage of non-emitting controllers that must comply by those deadlines. The basis provided for moving the compliance deadlines forward is that it would result in faster reductions in emissions, but the testimony fails to account for the number of controllers that are affected and the number of facilities that will be required to comply with this Section, and the time needed to come into compliance. Based on the testimony provided by the parties up to this point, the Department believes the proposed timelines are impractical and unreasonable. If compelling testimony is submitted that better supports a shortened compliance deadline and an increased percentage of non-emitting controllers, NMED would be open to supporting modification of the compliance deadlines based on that testimony.

The eNGO Parties propose to remove the requirement that allows for an owner or operator that has met a total of 75% of non-emitting controllers to have met the requirements of this Section. NMED does not agree with this proposal. The current requirement provides an incentive to owners and operators to more quickly transition to lower emitting pneumatics, resulting in faster overall emissions reductions.

The eNGO Parties propose to remove the provisions allowing owners and operators who are unable to retrofit the required percentages within the required compliance timeframes to submit a cost analysis of retrofitting the remaining units and obtain a waiver from the Department for meeting the additional retrofit requirements. NMED does not agree with this proposal. These provisions give a reasonable accommodation to address situations where a controller is not cost effective to retrofit. The Department 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.

The eNGO Parties propose revisions requiring owners and operators to conduct leak detection and repair activities in conformance with Section 20.2.50.116 on all controllers with a bleed rate greater than zero. NMED agrees with this proposal because it will address fugitive emissions from these devices.

Section 20.2.50.123 – Storage Vessels

NMOGA, CDG, and Oxy USA propose numerous revisions to Section 20.2.50.123. The Department agrees with many of these proposals and made technical and clarifying edits to

Section 20.2.50.123 in response. Revisions that were not agreed to by the Department are discussed in detail below.

Subsection A - Applicability

NMOGA proposes to revise the applicability threshold for existing storage vessels to six tons per year. NMED does not agree with this proposal. However, based on the higher cost effectiveness for controlling the smallest storage tanks ($13,779/ton for a 2 ton per year tank) NMED proposes to raise the applicability threshold for existing storage tanks to three tons per year. As explained in the direct testimony, the thresholds are based on other existing state regulations and are appropriate to secure meaningful reductions from this source group. Storage vessels represent a significant amount of VOC emissions from the NMED emissions inventory and securing considerable reductions is critical to reducing the emissions that drive ozone formation. The rule provides an offramp for uncontrolled vessels with actual emissions less than two tons per year of VOC, which is a reasonable accommodation for very low emitting storage vessels. Additional options are authorized for owners or operators to comply with the rule, such as shutting in the well in lieu of reducing emissions.

Oxy USA proposes to allow the use of actual emissions in lieu of calculating PTE under this Section. NMED does not agree with this 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 cannot be considered a reliable or representative emission rate with respect to determining applicability under this Section. PTE, on the other hand, 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.

NMOGA proposes revisions allowing emissions to be calculated using "generally accepted methods." NMED does not agree with this proposal. The proposed "generally accepted methods" are undefined, and thus unknown and 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. NMED has removed the requirement that "the calculation methodology shall be department approved" in the reporting requirement for the monthly actual emissions in Subsection D, Paragraph 1(d).

NMOGA proposes to allow averaging among storage vessels that are vapor manifolded together to determine an individual vessel's PTE. NMED agrees with this proposal based on NMOGA's comment on page 53 of Appendix B to NMOGA's Direct NOI.

NMOGA proposes to exempt sources subject to other federal emission standards from the requirements of this Section. NMED does not agree with this proposal. 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. Therefore, and in accordance with the statutory mandate in the AQCA, NMED is proposing more stringent emission control requirements than those provided under the federal regulations for storage vessels.

Subsection B – Emission Standards

NMOGA proposes to remove the requirement that existing and new storage vessels emitting greater than 10 tpy VOC reduce emissions by 98% in Paragraphs 2 and 4 of this Section. NMED agrees with this proposal based on the comments on page 53 of NMOGA Appendix B.

Oxy USA proposes to add a compliance schedule in this Subsection allowing existing units to comply on a graduated timeline. NMED agrees with this concept, but has scaled back the compliance deadline for each tier by a year, with all storage vessels required to comply by 2028 instead of 2029. NMED finds this compliance deadline reasonable but remains open to proposing revisions to the schedule if there is compelling testimony provided by other parties on this issue.

NMOGA proposes revisions to current Paragraph 5 to raise the emission threshold under which the requirements of this Section would cease to apply for existing storage vessels from two to four tons per year. NMED does not agree with this proposal, for which NMOGA has provided no explanation or rationale. As stated above, the intent of the rule is to require meaningful reductions in storage vessel emissions and the proposed threshold would exempt an unknown number of storage vessels from the control requirements of this Section.

NMOGA proposes revisions to current Paragraph 6 that would allow an operator to reduce production from a well in order to extend the time to comply with the emission standards. NMED does not agree with NMOGA's proposal to authorize the reduction of throughput to reduce emissions in order to comply with the requirements in this Section. 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. Thus, the proposed revisions are unnecessary.

Oxy USA proposes to delete this Paragraph in its entirety and suggests that their proposed phase-in timeline would account for the challenges in complying with the requirements for small tanks in a timely fashion. The Department disagrees that this Paragraph should be deleted as it is not a requirement but one option for compliance. The Department has added 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.

NMOGA proposes revisions to current Paragraph 6 that would allow requests for extensions to the deadlines of this Section. The Department disagrees with this proposal. As noted previously, the Department has revised this Section to include a graduated compliance schedule. The proposed compliance deadlines are reasonable, and provisions allowing for further extensions are not warranted.

NMOGA and Oxy USA propose revisions to current Paragraph 7 by removing the requirement to install a mechanism that requires thief hatches to close after overpressure is relieved. NMED agrees with these proposals for the reasons provided on page 53 of NMOGA Appendix B, and pages 16-17 of Oxy USA's witness Danny Holderman's direct testimony. NMOGA proposes further revisions that would allow owners and operators to also install a pressure relief device to ensure that overpressure can be adequately relieved. The proposed provision is unnecessary because owners and operators are already authorized to modify their equipment, so long as modifications are consistent with state permitting regulations.

Oxy USA proposes revisions to current Paragraph 9 that would authorize the use of alternative controls such as using biomass or carbon filters for low emitting storage vessels if approved by the Department. NMED does not agree with the specific proposal to modify the language in Paragraph 9 as such allowance 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.

CDG proposes revisions that would exempt control device requirements where it is technically infeasible to route emissions to a control device unless supplemental fuel is routed to the control device, and in other undefined circumstances. NMED does not agree with this proposal. The applicability threshold of two tons per year of VOC should be sufficient to address the concerns articulated by CDG, rather than adding further burdens to the Department's limited resources by requiring the Department to evaluate individual exemption requests. No testimony was provided regarding the number of vessels potentially impacted by this technical issue and, therefore, the department is unable to determine the potential number of sources impacted, their emissions profile or PTE, or where in the sector these vessels operate.

<u>Subsections C and D</u>

NMOGA proposes to remove the requirement to monitor and record throughput and instead calculate or estimate the throughput. NMED agrees with this proposal.

NMOGA proposes to remove the requirement to conduct a weekly AVO inspection and the requirement to inspect each vessel monthly to ensure compliance with this Section. NMED does not agree with this proposal. These requirements are critical for ensuring ongoing and recurring monitoring of storage vessels, which are frequently found during inspections to have significant excess emissions resulting from improperly monitored equipment, malfunctioning controls, and open thief hatches. This provision establishes a very reasonable inspection frequency designed to detect and address such issues in a timely manner in order to prevent uncontrolled emissions releases and ensure the equipment is maintained in good working order.

NMED does not agree to revise language requiring the Department to review or approve an extension to the deadlines of this Part. 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.

Subsection D – Recordkeeping Requirements

NMOGA proposes to remove the language in Subparagraph 1(d) providing that the PTE calculation methodology shall be approved by the Department. The Department has revised this condition to require monthly recordkeeping of actual emissions, and has deleted the requirement that the calculation methodology be approved by the Department. As stated previously, Department-approved emission estimation methodologies are publicly available and owners and operators may contact the Department directly for approval of alternative methods.

NMOGA proposes to remove the recordkeeping requirement confirming that the required leak check was performed. The Department agrees with this change as the inspection record required under 20.2.50.123.D.3 provides adequate documentation that the required leak check was performed.

Section 20.2.50.124 – Well Workovers

NMOGA and IPANM propose the following revisions to this Section:

- Subsection B – change “good engineering practices” to “good operational practices” (NMOGA);
- Subsection C, Paragraph 2 and Subsection D, Paragraph 1(g) – specify that the required calculations of volume and mass of VOC vented are estimated calculations (NMOGA and IPANM);
- Subsection D, Paragraph 1(g) – require calculation of gas composition of VOC, instead of mass of VOC when estimating VOC emissions (NMOGA and IPANM);
- Subsection E – Paragraph 2 – Remove entire requirement to notify residents within ¼ mile of the well by certified mail within three calendar days of the workover event (IPANM); and
- Subsection E, new Paragraph 3 – provide an exception to the 3-day notification requirement in Paragraph 2 for emergency or routine workovers due to upsets or equipment malfunctions, allowing notification of the public within 24 hours of the event (NMOGA).

NMED agrees with all the proposed revisions with the exception of IPANM’s proposal to remove the requirement in Subsection E, Paragraph 2 to notify residents by certified mail within three calendar days of a planned workover event. However, NMED is proposing to modify the requirement to allow other notification options besides certified mail, so long as they can be documented. NMED recognizes 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.

Section 20.2.50.125 – Small Business Facilities

NMOGA and IPANM propose to remove Section 20.2.50.125 in its entirety. Both parties claim that they are unaware of any companies in New Mexico that would meet the thresholds in the definition of small business facility in Section 20.2.50.7. IPANM stated its preference that NMED reinstate the exemptions for low producing and low PTE facilities, as proposed in the pre-petition draft rule that NMED released for public input in July of 2020.

NMED does not agree with NMOGA and IPANM's assertion that few if any oil and gas operators in New Mexico could qualify for the small business definition in Section 20.2.50.7. Neither party provided evidence to support this statement.

Under the proposed rule, a "small business facility" is defined as 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. As described in the direct testimony of Susan Day at NMED Exhibit 102, ERG obtained revenue and employment data for facilities meeting this definition, also referred to as global ultimate parent companies.[2] ERG constructed a data set of global ultimate parent companies associated with each active NM well owner/operator which clearly identifies global ultimate parent companies with gross annual revenues of less than $250,000 and no more than 10 employees. *See* NMED Exhibit 105 - Preliminary Results NAICS_COM Updated Spreadsheet.

[2] Information on revenues and employment for global ultimate parent companies can be obtained from commercially available business databases such as Dun and Bradstreet ("D&B"). D&B is a fee for service operation, typically dealing in transactions for large scale queries (e.g., an entire industry sector). Due to the limited size of the universe of facilities covered by Part 50, it was cost effective for ERG to purchase the needed D&B data from another vendor called NAICS Association, LLC ("NAICS Association").

NMED agrees with IPANM's statement that gross annual revenues are not a measure of profitability. 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." EPA Guidelines for Preparing Economic Analyses (March 2016) at p. 9-14, attached as NMED Rebuttal Exhibit 10. 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.

NMED does not agree to remove this Section, or to reinstate the exemptions in the draft rule it released prior to filing the Petition for Rulemaking in this matter. As discussed in NMED's direct testimony at NMED Exhibit 32, this Section provides a scaled-back set of requirements for small businesses to provide relief from compliance burdens for small, independent operators. Neither NMOGA nor IPANM provided testimony addressing the data that ERG compiled and made available for review showing numerous companies operating in the State that would qualify for the reduced compliance burdens under the definition. Nor did either party propose revisions to the definition to suggest new staffing or revenue thresholds, or otherwise address their concerns about the workability of this concept. Therefore, there is no rationale or evidence to support removing or revising this Section as proposed by NMOGA and IPANM.

Section 20.2.50.126 – Produced Water Management Units

<u>Section A – Applicability</u>

CDG proposes to revise the applicability section to require PWMUs with equal to or greater than 25 tpy VOC to obtain an air permit from NMED and subsequently be excluded from this Section. NMED does not agree with this 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. The Department 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.

Subsection B – Emission Standards

NMOGA proposes to substitute "operational" for "engineering" in Paragraph 1 with respect to the types of practices required for minimizing VOC emissions. NMED has proposed revisions to this paragraph to specify use of good operational or engineering practices.

CDG proposes to revise Paragraph 2 require that an owner operator either control VOC emissions from PWMUs to below 2 tpy, submit an NOI, or obtain a permit. NMOGA similarly proposes to require owners and operators to calculate the uncontrolled PTE for each PWMU and submit a NOI or a permit application to the Department. NMED does not agree with these proposals. However, NMED has proposed revisions to this paragraph removing the requirement to control VOC emissions to below 2 tpy, and has added a requirement prohibiting owners or operators from dumping 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. This new provision requires that produced water be treated to reduce emissions before they can be released to the atmosphere.

Subsection C – Monitoring Requirements

In response to the comments of CDG and NMOGA, NMED has proposed a new Paragraph 1 in this Subsection requiring that owners and operators develop a protocol to calculate the VOC emissions from each PWMU. The protocol shall include, at a minimum: monitoring of the produced water throughput through the unit; semi-annual sampling and analysis of the liquid composition; hydrocarbon measurement method(s); representative sample size; and chain of custody requirements. The protocol will standardize how owners and operators collect samples, monitor throughput, and use the data collected to calculate the VOC emissions emitted from the PWMU.

CDG proposes to remove the requirement in Paragraph 1 that emissions calculations be performed monthly on a rolling 12-month basis, and instead require calculation of total actual VOC emissions from each PWMU on an annual basis. NMOGA proposes to clarify that first emission calculations must be performed beginning within 180 days after the effective date of Part 50. NMED agrees with CDG's proposal to remove the reference to a monthly rolling 12-month total calculation, as the rolling of emissions calculations on a monthly basis is not necessary to track annual emissions. NMED proposes to keep the calculation frequency as monthly, but has adjusted the recordkeeping requirement to a single record of the total annual VOC emissions. NMED agrees with NMOGA's proposal to clarify when the first month's emissions calculations are required to be performed and agreed to add "operational" to require the use of best management practices and either good operational or engineering practices to minimize emissions of VOC from PWMU.

CDG proposes to remove the requirement that to monitor best management practices and engineering practices to ensure their effectiveness, and instead require the owner or operator to annually record such practices in order to demonstrate their effectiveness. NMED did not agree to delete "reduce emissions" from the requirement to monitor best management practices. NMED agrees to add the term "demonstrate" but does not agree to delete the term "ensure" from the requirement to monitor best management practices ("BMPs"), and does not agree to substitute a requirement to record BMPs for the requirement to monitoring them. BMPs are used to prevent or reduce emissions from being emitted into the air, which is consistent with the intent of this requirement. Thus, 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.

CDG proposes to remove Paragraph 3 requiring compliance with the monitoring provisions of 20.2.50.112. NMED does not agree to this revision. While NMED recognizes that this language is somewhat redundant, we believe it provides clarity to regulated entities in terms of understanding what monitoring requirements they are subject to under Part 50.

<u>Subsection D – Recordkeeping Requirements</u>

CDG proposes to remove the provisions in in Paragraph 1(c) requiring recording of the annual emissions, and to substitute an annual record of the best management practices used. NMED does not agree with this revision. However, NMED does 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.

Section 20.2.50.127 – Credible Information Presumption

The Department worked with NMOGA, Oxy USA, Clean Air Advocates, and EDF to come up with proposed revised language for Section 20.2.50.127. The Department provided the proposed language to all the Parties, and all have agreed to stipulate to the following changes indicated in redline:

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE ~~INFORMATION PRESUMPTION~~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, ~~the source shall be presumed to be~~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~~ unless and until the owner or operator provides credible evidence or information demonstrating otherwise~~.

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

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

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]

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.

A. If, at any time after the effective date of this Part, any area 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 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 such 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.

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.

~~This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule 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. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.~~
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 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]

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

20.2.50.5 EFFECTIVE DATE: Month XX, 2022~~1~~, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

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]

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. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM 21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

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

C. "Bleed rate" means the rate in standard cubic feet per hour at which ~~natural~~ gas is continuously~~ or intermittently~~ vented from a pneumatic controller.

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

E. "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 ~~S~~screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "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.

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

H. "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.

I. "Connector" means flanged, screwed, or other joined fittings used to connect pipe~~-~~line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe~~-~~line 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.

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

~~**K. "Custody transfer"** means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.~~

K~~L~~. "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 include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, ~~air fuel ratio controllers (AFRs),~~ 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.

L~~M~~. "Department" means the New Mexico environment department.

M. "Design value" means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

N. "Downtime" means the period of time when equipment is not in operation~~, or when a well is producing, and the control device is not in operation~~.

O. "Enclosed combustion device" means a combustion device where ~~gaseous~~ waste gas~~fuel~~ 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~~, reboiler, and heater~~.

P. "Existing" means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

Q. "Gathering and boosting station" means a permanent combination of equipment 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. ~~means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.~~

R. "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.

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.

T. "Liquid unloading" means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

U. "Liquid transfer" means the ~~loading and~~ unloading of a hydrocarbon liquid ~~or produced water~~ from ~~between~~ a storage vessel ~~and~~ to a tanker truck or tanker rail car for transport.

V. "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.

W. "Natural gas compressor station" means ~~one or more compressors~~a facility, including all equipment and compressors, designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. Natural gas compressor stations include transmission compressor stations.

X. "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.

Y. "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.

Z. "New" means constructed or reconstructed on or after the effective date of this Part.

AA. "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.

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

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

DD~~CC~~. "Owner" means the person or persons who own a stationary source or part of a stationary source.

EE~~DD~~. "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.

FF~~EE~~. "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.

(1) "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.

(2) "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.

(3) "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.

(4) "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.~~means an instrument that~~

~~is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.~~

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

HH~~GG~~. "Potential to emit (PTE)" means the maximum capacity of a stationary source to emit any air pollutant~~contaminant~~ under its physical and operational design. ~~The~~ Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and ~~a~~ 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.

II~~HH~~. "Produced water" means a ~~fluid~~ liquid that is an incidental byproduct from well completion ~~drilling for~~ and ~~or~~ the production of oil and gas.

JJ~~II~~. "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), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

KK~~JJ~~. "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.

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

MM~~LL~~. "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.

NN~~MM~~."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.

OO~~NN~~. "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. ~~of the corporation if the representative is responsible for the overall operation of the source.~~

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

PP~~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, 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.

QQ~~PP~~. "Startup" means the setting into operation of air pollution control equipment or process equipment.

RR~~QQ~~. "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.

~~R~~SS~~R~~. "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, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. 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, or a pressure vessel designed to operate in excess of 204.9 kilopascals (29.72 psi) without emissions to the atmosphere.

TT. "Transmission Compressor Station" means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

~~SS.~~UU. "Well workover" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

VV~~TT~~. "Well~~head~~ site" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A well~~head~~ site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

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

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]

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]

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]

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]

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.]

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 ~~and~~ 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~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations, up to the point of the local distribution company custody transfer station.

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.

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.

D. Oil refineries~~y~~, ~~and~~ transmission pipelines, and saltwater disposal facilities are not subject to this Part.

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

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, ~~and~~ or good engineering and ~~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 maintenance practic~~ ~~es on file~~ and make them available upon request by the department. ~~For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.~~The terms of 20.2.50.112.A(1) apply any time reference to manufacturer specifications occurs in this Part.

(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 which is 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 if levels required by the applicable standard have been achieved. The terms of 20.2.50.112.A(2) apply any time reference to minimizing emissions occurs in this Part.~~subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.~~

(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 database system capable of storing information for each source in a manner consistent with this section.~~an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part.~~ The owner or operator shall maintain information regarding each source requiring equipment monitoring, testing, or inspection in a database system, including ~~The EMT shall be maintained by the owner or operator, and data in the EMT shall provide~~ at a minimum, the following information:

(a) unique ~~unit~~ 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~~PTE~~ in lbs./hr. and tpy;

(e) for a control device, the controlled VOC and NO_x emissions~~PTE~~ in lbs./hr. and tpy;

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

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

(4) The database system(s) ~~EMT~~ shall be ~~installed and~~ maintained by the owner or operator of the facility.

~~**(5)** The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.~~

(5~~6~~) The owner or operator shall manage the source's record of data in the~~a~~ database system(s). The owner or operator shall ~~that is able to~~ generate a Compliance Database Report (CDR) from the information in the database system. The CDR is an electronic report maintained by the owner or operator and that can ~~generated by the owner or operator's database and~~ be submitted to the department upon request. ~~The format of the CDR shall be determined by the department.~~

(6~~7~~) The CDR is a report distinct from the owner or operator's database system(s). The department does not require access to the owner or operator's database system(s), only the CDR.

(7~~8~~) T~~If read by t~~he owner or operator's authorized representative must be able to access and input data in the ~~, the EMT shall access the owner or operator's~~ database system(s) record for that source. That access is not required to be at any time from any location.

(8~~9~~) The owner or operator shall contemporaneously track each ~~compliance~~ monitoring event ~~for each source subject to the EMT requirements of this Part~~, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database 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. By January 1, 2023, the department shall finalize a list of approved technologies to comply with this requirement and shall post the approved list on its website. Owners and operators shall comply with this requirement using an approved technology by April 1, 2023. Prior to April 1, 2023, 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~~b~~) data required by this Part shall be maintained in the database system(s) for at least five years.

(9~~10~~) The department 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.

(10) Where Part 50 refers to applicable federal standards 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.

(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.

B. Monitoring requirements:

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

(2) Sources subject to emission standards and monitoring ~~(e.g. inspection, testing, parametric monitoring)~~ requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, 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.

(3~~2~~) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy under 20.2.50.116 NMAC. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under 20.2.50.116 NMAC ~~the applicable Section~~ and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(4~~3~~) For e~~E~~ach monitoring event, the owner, operator, or authorized representative ~~(e.g. testing, inspection, parametric monitoring)~~ shall monitor as required by the applicable sections of this Part. ~~be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:~~

~~**(a)** date and time of the testing, monitoring, or inspection event;~~

~~**(b)** name of the personnel conducting the testing, monitoring, or inspection;~~

~~**(c)** identification number and type of unit;~~

~~**(d)** a description of any maintenance or repair activity conducted; and~~

~~**(e)** results of testing, monitoring, or inspection as required under this Part.~~

C. Recordkeeping requirements:

(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.~~following data:~~

~~**(a)** date and time of the testing, monitoring, or inspection event;~~

~~**(b)** name of the personnel conducting the testing, monitoring, or inspection;~~

~~**(c)** identification number and type of unit;~~

~~**(d)** a description of any maintenance or repair activity conducted; and~~

~~**(e)** results of any testing, monitoring, or inspections required under this Part.~~

(2) The owner or operator shall keep an electronic record required by this Part for five years. ~~The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.~~

(3) By March 1 of each calendar year, the owner or operator shall conduct a compliance evaluation and prepare an electronic record certifying the compliance status of each source subject to this Part with all terms, conditions, and applicable requirements. The compliance evaluation and certification shall include all sources subject to this Part for the previous calendar year.

~~**(3)** Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for for five years.~~

D. Reporting requirements: Within three business days~~24 hours~~ of a request by the department, the owner or operator shall for each ~~unit~~ source subject to the request, provide the requested information ~~either by~~ 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 may be given as appropriate.

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

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations, with a rated horsepower greater than the horsepower ratings of t~~T~~able 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.

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.~~.~~

(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 approved pursuant to Paragraph (10) of Subsection B of 20.2.50.113 NMAC: ~~as follows:~~

(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~~s~~ 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~~s~~ 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.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED~~, OR 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	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
~~Lean burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~47 ppmvd @ 15% O_2 or 93% reduction~~	~~0.70 g/bhp-hr~~
~~Rich burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~

(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 NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED~~, OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC~~.~~

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
~~Lean burn~~	~~>500 - <1,000~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~
Lean-burn	> 500 and ~~≥1,000~~ < 1875	0.5~~3~~0 g/bhp-hr ~~uncontrolled or 0.05 g/bhp-hr with control~~	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

(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.

(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.

(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.

(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:

(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.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each applicable natural gas-fired combustion turbine constructed or reconstructed ~~and installed~~ before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than ~~two years from the effective date of this Part~~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~~5~~,000	150	50	9
≥4~~5~~,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each applicable natural gas-fired combustion turbine constructed or reconstructed ~~and installed~~ on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <4~~5~~,000	~~25~~100	25	9
≥4~~5~~,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

(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.

~~**(9)** The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.~~

(9~~10~~) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~that is operated less than 100 hours per year~~ 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.

(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 under 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.

(11) If an owner or operator is unable to meet the emission standards of this section through an ACP, 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. To qualify for an alternative emission standard, an owner or operator must comply with the following requirements:

(a) prepare a demonstration detailing why emissions from the individual engine or turbine cannot be addressed through an ACP;

(b) 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

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

(d) 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.

(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 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.

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

(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 engine replacement 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.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the ~~minimum~~ manufacturer recommended maintenance schedule as defined in 20.2.50.112 NMAC. ~~The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:~~

~~**(a)** routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and~~

~~**(b)** unscheduled repairs that require a unit to be taken out of service for more than~~

~~two hours during any 24-hour period.~~

(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~~2~~) 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 ~~or supplier recommended maintenance schedules, including~~ 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~~3~~) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 ~~NMAC~~ 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. ~~by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method.~~ For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

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

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

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; 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 events shall be conducted within 10 percent of 100 percent peak (or the highest achievable) load. ~~at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions.~~ 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 D-6522. 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.

(i) for emissions testing using a portable analyzer, 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~~4~~) 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~~3~~) of Subsection C of 20.2.50.113 NMAC.

(6~~5~~) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated for less than 100 hours per year~~ shall monitor the hours of operation by a non-resettable hour meter.

(7~~6~~) 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~~7~~) Prior to any monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall date and time stamp the event~~scan the EMT~~, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 and 113 NMAC~~20.2.50.112 NMAC~~.

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~~and EMT~~ 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;

(d~~c~~) 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 ~~personnel~~ 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 ~~activity~~ 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) ~~the~~ make, model, and serial number~~, and EMT~~ for the tested engine or turbine;

(b) the date and time stamp(s), including GPS of the location, of any monitoring event, including~~of~~ sampling or measurements;

(c) ~~the~~ date analyses were performed;

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

(e) ~~the~~ analytical or test methods used;

(f) ~~the~~ results of analyses or tests;

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

~~**(g)** for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and~~

(h~~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 ~~operated less than 100 hours per year~~ 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.

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]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

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

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, ~~under negative pressure~~ and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(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~~eight~~ 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 ~~under negative pressure~~ and route them via a closed vent system to a control device, a recovery system, fuel cell, or a process stream.

~~**(5)** The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.~~

(5~~6~~) 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.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) 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.

(3) 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 ~~under negative pressure~~as designed and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) 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.

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

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, reconstruction, or modification 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 ~~personnel~~ 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 ~~number~~ 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, reconstruction, or modification 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 records of pressure in~~ the rod packing emissions collection system, as applicable; and

(iii) the time and date of the inspection, the ~~personnel~~ person(s) conducting the inspection, ~~a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed,~~ a description of any problems observed during the inspection, and a description ~~and date~~ 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.

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]

20.2.50.115 CONTROL DEVICES AND CLOSED VENT SYSTEMS:

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.

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 expected range of inlet VOC or NOx concentrations or volumes. ~~fluctuations in emissions of VOC or~~ ~~NO_x.~~

~~**(3)** The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.~~

(3~~4~~) The owner or operator shall inspect control devices visually or consistent with applicable federally approved inspection methods ~~used to comply with this Part~~ at least monthly to identify defects, leaks, and releases, and to ensure proper ~~maintenance and~~ operation. Prior to an inspection or monitoring event, the owner or operator shall date and time stamp the event, ~~scan the EMT~~ and the required monitoring data entry shall be made ~~electronically captured~~ in accordance with this Part.

(4~~5~~) 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 ~~and that~~ unburnt gas ~~is not directly vented~~ to the atmosphere.

(5~~6~~) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic ~~controller or~~ pump, or storage vessel 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 ~~all~~ 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 ~~all~~ emissions from the affected equipment are routed to the control device or process; and

(c) have the ~~closed vent system~~ assessment certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of ~~the~~ 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 ~~design and capacity~~ assessment was prepared under my direction or supervision. I further certify that the closed vent system ~~design and capacity~~ 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."

(6~~7~~) The owner or operator shall keep manufacturer specifications ~~manufacturer specifications~~ for all control devices on file. The information shall include the ~~. The information shall include:~~

~~**(a)**~~ unique identification number, type of unit, manufacturer name, make, ~~and~~ model, capacity, and destruction or reduction efficiency data. ~~;~~

~~**(b)** maximum heating value for an open flare, ECD, or TO;~~

~~**(c)** maximum rated capacity for an open flare, ECD/TO, or VRU;~~

~~**(d)** gas flow range for an open flare, ECD, or TO; and~~

~~**(e)** designed destruction or vapor recovery efficiency.~~

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.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (c~~C~~) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(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.

(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 constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(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, ~~EMT on the flare shall be scanned~~ and the required monitoring data entry ~~s~~shall be made ~~electronically captured during the event i~~in accordance with ~~the monitoring requirements of~~ this Part~~20.2.50.112 NMAC~~; and

~~**(e)**~~**(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 or 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 ~~personnel~~ 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

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

~~**(e)** any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.~~

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

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 ~~an~~ 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~~one~~ years after the effective date of this Part. ~~New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.~~

(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.

(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, ~~EMT on the unit shall be scanned~~ and the required monitoring data entry shall be made ~~electronically captured during the monitoring event~~ in accordance with the monitoring requirements of ~~20.2.50.112 NMAC~~this Part.

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

(a) any instance of a thermocouple or other approved technology or flame detection device~~an~~ 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 ~~personnel~~ person(s) conducting the inspection, and any maintenance activities performed;

(b) the result of ~~the~~ any U.S. EPA method 22 observation;

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

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

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

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.

(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.

(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, ~~EMT on the unit shall be scanned~~ and the required monitoring data entry shall be ~~electronically captured during the monitoring event i~~made in accordance with the ~~monitoring~~ requirements of this Part~~20.2.50.112 NMAC~~.

(3) Recordkeeping requirements: ~~-~~For a VRU inspection or monitoring event, the owner or operator shall record the result of the event~~ in accordance with 20.2.50.112 NMAC~~, including the name of the ~~personnel ~~person(s) conducting the inspection, ~~and ~~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.

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

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

(2) the information required in Paragraph (6~~7~~) of Subsection B of 20.2.50.115 NMAC.

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

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, gas processing plants, natural gas ~~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.

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

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

(1) The owner or operator of a 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 audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct an external visual inspection for defects, which may include~~:~~ cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

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

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

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

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

(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 a defect and leaking component as specified in Subparagraphs (a) through (d~~e~~) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

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

(a) for existing well sites or tank battery facilities constructed prior to the effective date of this Part, the owner or operator shall comply with these requirements within two years of the effective date of this Part.

(b) for well~~head~~ sites or tank battery facilities:

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

(i~~i~~) annually at facilities with a PTE equal to or greater than two tpy and less than six~~two~~ tpy VOC;

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

(iv~~ii~~) quarterly at facilities with a PTE equal to or greater than twelve~~five~~ tpy VOC.

(c~~b~~) for gathering and boosting ~~sites~~stations, gas processing plants, and ~~and transmission~~ natural gas compressor stations:

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

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

(d) annually at transmission compressor stations and at any facility producing or processing exclusively coal bed methane.

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

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

~~**(b)** the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane;~~ and

(b~~c~~) 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.

(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.

(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~~, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground~~;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

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

(7) Prior to any monitoring event, the owner or operator shall date and time stamp the monitoring event.

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

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

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

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

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

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

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

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with ~~the~~ 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 ~~under~~ of Subsection C of 20.2.50.116~~.C~~ NMAC within 15 days.

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

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

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

(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.

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~~date of inspection~~;

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

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

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

(f) whether a visible t~~fl~~ag was placed on the leak or not;

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

(a) the date the leak is detected;

(b) the date of attempt to repair;

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

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

(ii) signature of the ~~authorized representative~~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.

G. Reporting requirements:

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

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

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

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations resulting in the venting of natural gas ~~including down-hole well maintenance events~~ 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 (3) of Subsection B of 20.2.50.117 NMAC within one year 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 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 liquid unloading in close proximity to the well or via remote telemetry; and

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

(3) The owner or operator of a natural gas well shall employ methodologies ~~use one of the following methods~~ to reduce emissions during venting associated with a liquid ~~an~~ unloading event:

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

(b) ~~installation and~~ use of ~~an~~ artificial lift ~~engine~~; ~~or~~

(c) ~~installation and~~ use of a control device;

(d) use of an automated control system; or

(e) other control if approved by the department~~.~~

. ~~**(4)** The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.~~

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 ~~vented~~ emitted during a venting event associated with a liquid unloading event.

~~**(3)** A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.~~

(3~~4~~) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC~~in 20.2.50.112 NMAC~~.

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~~date the liquid unloading was performed~~;

(c) wellhead pressure;

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

(e) duration of venting to the storage vessel, tank battery, or atmosphere;

(f) a description of the management practice used to minimize venting ~~release~~ of VOC emissions before and during the ~~-~~ liquid unloading;

(g) the type of control device or control technique used to control VOC emissions during venting associated with the~~the~~ liquid unloading event; and

(h) a calculation of the VOC emissions vented during a~~the~~ liquid unloading event based on the duration, calculated volume, and ~~mass of~~composition of the produced gas~~ VOC~~.

(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.

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

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.118 NMAC.

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) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas ~~gathering~~ pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts, and a compressor that reinjects the ~~n~~vapor~~atural gas~~ 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) still vent and flash tank emissions shall not be vented directly to the atmosphere during normal operation.~~; and~~

~~**(d)** the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.~~

(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 ~~uncontrolled~~ actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

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~~3~~) 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~~4~~) Owners and operators shall comply with the monitoring requirements in 20.2.50.112~~of this part~~ NMAC.

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)~~and identification number~~;

(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) ~~amount of~~ 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~~f~~) ~~date and~~ results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(h~~g~~) a copy of the glycol dehydrator manufacturer specifications ~~operation and maintenance recommendations~~.

(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.

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]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 2~~1~~0 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.119 NMAC.

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	4~~3~~00
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	40~~13~~0

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than ~~one~~ three years~~year~~ 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.

~~**(4)** The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.~~

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~~ and good engineering practices~~;

(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 engineering practices~~; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with 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~~, inspection, maintenance, or repair~~ event, the owner or operator shall date and time stamp the event, ~~the owner or operator shall scan the EMT~~ and the required monitoring data entry shall be made~~captured~~ in accordance with this Part.

(5) The owner or operator shall comply with the monitoring requirements of 20.2.50.112 NMAC.

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; and

(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 ~~was~~ conducted;

(b) name of the ~~personnel~~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.

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]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at existing well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.120 NMAC ~~beginning~~ within ~~one~~ two years ~~from~~ of the effective date of this Part. Hydrocarbon liquid transfers located at new well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or natural gas compressor stations are subject to the requirements of 20.2.50.120 NMAC upon startup. Any facility connected to oil sales pipelines that are routinely used for hydrocarbon liquid transfers are not subject to the requirements of 20.2.50.120 NMAC. Well sites, tank batteries, gathering and boosting stations, natural gas processing plants, or natural gas compressor stations that load out hydrocarbon liquids to trucks fewer than thirteen (13) times in a calendar year are not subject to 20.2.50.120 NMAC. When transferring hydrocarbon liquid from a transfer vessel to a storage vessel subject to the emission standards in 20.2.50.123 NMAC, no requirements under this Section apply.

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-~~eight~~ 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. ~~transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.~~

(2) An owner, ~~or~~ operator, or personnel conducting the hydrocarbon liquid transfer using vapor balance ~~during a liquid transfer~~ operation shall:

(a) transfer the vapor displaced from the ~~vessel~~ 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 ~~ensure that~~ connector pipes, hoses, couplers, valves, and pressure relief devices for leaks~~are maintained in a leak-free condition~~;

(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)** Bottom loading or submerged filling shall be used for the liquid transfer.~~

(3~~4~~) Connector pipes and couplers shall be inspected and maintained in a leak-free condition.

(4~~5~~) Connections of hoses and pipes used during hydrocarbon liquid transfer operations 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~~6~~) Liquid leaks that occur shall be cleaned and disposed of in a manner that ~~prevents~~ 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~~7~~) 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.

C. Monitoring requirements:

(1) The owner or operator or their designated representative shall visually inspect the hydrocarbon liquid transfer equipment monthly at staffed locations and semi-annually at unstaffed locations ~~during a transfer operation~~ 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 liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

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

~~**(a)** method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 inches H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O (six inches H_2O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.~~

~~Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE~~

~~Cargo tank or compartment capacity, liters (gallons)~~	~~Allowable vacuum change (Δv) in five minutes, mm H_2O (inches H_2O)~~	~~Allowable pressure change (Δp) in five minutes, mm H_2O (inches H_2O)~~
~~< 3,785 (< 1,000)~~	~~64 (2.5)~~	~~102 (4.0)~~
~~3,785 < 5,678 (1,000 < 1,500)~~	~~51 (2.0)~~	~~89 (3.5)~~
~~5,678 < 9,464 (1,500 < 2,500)~~	~~38 (1.5)~~	~~76 (3.0)~~
~~> 9,464 (> 2,500)~~	~~25 (1.0)~~	~~64 (2.5)~~

~~**(b)** pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:~~

~~**(i)** after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H_2O (18 inches H_2O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.~~

~~**(ii)** relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H_2O (five inches H_2O).~~

(3~~4~~) 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.

~~**(5)** Owners and operators shall comply with the monitoring requirements in 20.2.50.112 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.

D. Recordkeeping requirements:

~~**(1)** The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:~~

(1~~2~~) The owner or operator shall maintain a record of ~~the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include~~ 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~~time and date of the~~ inspection~~ and testing~~;

(d~~b~~) the name of the ~~personnel~~ person(s) conducting the inspection~~ and testing~~;

(e~~c~~) a description of any problem observed during the inspection~~ and testing~~; and

(f~~d~~) the results of the inspection ~~and testing~~ and a description of any repair or corrective action taken.

(2~~3~~) 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~~4~~) 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.

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

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Individual p~~P~~ipeline pig launch~~ing~~ers and receiv~~ing~~ers operations with a PTE equal to or greater than 1 tpy VOC located within~~ or outside of~~ the property boundary of, and under common ownership or control with, ~~of~~ well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, and ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of affected pipeline pig launch~~ing~~ers and receiv~~ing~~ers operations ~~with a PTE equal to or greater than one tpy of VOC~~ shall capture and reduce VOC emissions from pigging operations by at least ninety-~~eight~~ five percent~~,~~ within two years of the ~~beginning on 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 ~~the~~ pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to ~~prevent~~ 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 ~~prevents~~ 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 ~~uncontrolled~~ actual annual VOC emissions of the launcher or receiver ~~the~~ operation are less than one ~~half~~ tpy~~on per year~~ of VOC.

(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.

C. Monitoring requirements:

(1) ~~The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.~~

~~**(2)**~~ The owner or operator of an affected pig launching and receiving ~~operations~~site shall inspect the equipment for ~~a~~ 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 ~~immediately before~~ the commencement and~~d immediately~~ after the conclusion of the pig launching or receiving operation, ~~and according to the requirements in 20.2.50.116 NMAC~~if less frequent.

(2~~3~~) 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 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.

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

D. Recordkeeping requirements:

(1) The owner or operator of an affected pig launching and receiving ~~operations~~ site shall maintain a record of the following:

(a) the pigging operation, including the location, date, and time of the pigging operation ~~and the type and volume of liquid cleared~~;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE;

(c) date and time of any monitoring and the results of the monitoring; and

(d~~e~~) the type of control device and its ~~location,~~ make~~,~~ and model.

(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.

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

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, ~~and~~and natural gas compressor stations ~~transmission compressor stations~~ are subject to the requirements of 20.2.50.122 NMAC.

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.

(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~~HEAD~~ SITES, TANK BATTERIES, GATHERING AND BOOSTING ~~FACILITIES~~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 – NATURAL GAS 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%

(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.

(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 ~~has satisfied~~ 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 ~~shall~~ 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 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 ~~a~~ natural gas processing plants shall have an emission rate of zero.

(b) new pneumatic diaphragm pumps located at ~~a~~ well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, or ~~transmission~~ natural gas 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 natural gas 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~~e~~) owners and operators of pneumatic diaphragm pumps located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, or ~~transmission~~ natural gas 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.

~~**(6)** The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.~~

C. Monitoring requirements:

(1) Pneumatic controllers or diaphragm pumps not using natural gas or other hydrocarbon gas as a motive force ~~with a natural gas bleed rate equal to zero~~ 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 ~~a~~ 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 ~~with a bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the controller and~~ 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 ~~EMT shall be linked to a~~ owner or operator's database ~~that~~ shall contain~~s~~ 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) design annual bleed in standard cubic feet per year.

(5) The owner or operator of a natural gas-driven pneumatic diaphragm pump ~~with a bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the pump and~~ 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 with a bleed rate greater than zero 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.

D. Recordkeeping requirements:

(1) Non-emitting ~~P~~pneumatic controllers and diaphragm pumps ~~with a natural gas bleed rate equal to zero~~ 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.

(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~~oller with a natural gas bleed rate greater than zero~~. 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~~inspection dates~~;

(c) name of the ~~personnel~~ person(s) conducting the inspection;

(d) AVO or OGI inspection result;

(e) AVO or OGI level discrepancy in continuous or intermittent bleed rate;

(f) maintenance date and maintenance activity; and

(g) a record of the justification and certification required in Subparagraph (d) 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 ~~in the EMT database of the pneumatic controller~~ 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 ~~in the EMT database~~ 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 ~~a~~ 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.

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]

20.2.50.123 STORAGE VESSELS

A. Applicability: New s~~S~~torage vessels with a ~~n uncontrolled~~ PTE equal to or greater than two tpy of VOC and existing storage vessels with a PTE equal to or greater than three tpy of VOC and located at well~~head~~ sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, or ~~transmission~~ natural gas compressor stations are subject to the requirements of 20.2.50.123 NMAC. Storage vessels 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.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than three~~two~~ tpy of ~~and less than 10 tpy of~~ VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent according to the following schedule. ~~no later than three years after 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.

(a) By January 1, 2024, an owner or operator shall ensure at least 35% of the company's existing storage vessels are controlled;

(b) By January 1, 2026, 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, 2028, an owner or operator shall ensure the remaining existing storage vessels are controlled.

~~**(2)** An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.~~

(2~~3~~) A new storage vessel with a PTE equal to or greater than two tpy of ~~and less than 10 tpy of~~ VOC 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.

~~**(4)** A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.~~

(3~~5~~) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the ~~uncontrolled~~ actual annual VOC emissions decrease to less than two tpy.

(4~~6~~) If a control device is not installed by the date specified in Paragraphs (1) ~~through~~ and (2~~4~~) 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.

(5~~7~~) The owner or operator of a new or existing storage vessel with a thief hatch shall ensure ~~install a control device that allows~~that -the thief hatch is capable of ~~to~~ opening sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. ~~The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.~~Any pressure relief device installed must automatically close once the vessel overpressure is relieved.

~~**(8)** The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.~~

(6~~9~~) An owner or operator complying with Paragraphs (1) ~~through~~ and (2~~4~~) 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.

C. Monitoring requirements: -The owner or operator of a storage vessel shall:

(1) monthly, monitor ~~on a monthly basis~~, or 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 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, 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.~~scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;~~

(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) ~~through~~ and (2~~4~~) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements of 20.2.50.112 NMAC ~~in 20.2.50.112 NMAC~~.

D. Recordkeeping requirements:

(1) Monthly, t~~T~~he owner or operator shall~~, on a monthly basis,~~ maintain a record ~~in accordance with 20.2.50.112 NMAC~~ for each~~a~~ storage vessel of the following~~. The record shall include~~:

(a) unique identification number and ~~the vessel~~ location (latitude and longitude)~~ and identification number~~;

(b) monitored, calculated, or estimated monthly liquid throughput;~~ and the most recent date of measurement;~~

(c) the ~~average monthly~~ upstream separator pressure, if a separator is present;

(d) the data and methodology used to calculate the actual emissions of ~~PTE of~~ VOC (tpy); ~~(the calculation methodology shall be department approved);~~

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput ~~in~~ shall be verified 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) A record of the inspections required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the date and time stamp, including GPS of the location,~~and date~~ of the inspection;

(b) the ~~personnel~~ person(s) conducting the inspection;

~~**(c)** a notation that the required leak check was completed;~~

(c~~d~~) a description of any problem observed during the inspection; and

(d~~e~~) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) ~~through~~ and (2~~4~~) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

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

E. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) ~~through~~ and (2~~4~~) 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]

20.2.50.124 WELL WORKOVERS

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.

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.

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.

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; ~~and~~
(g) calculation of the estimated VOC emissions vented during the workover based on the duration, volume, and ~~mass~~ gas composition~~of VOC~~; 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.

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]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

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~~10~~) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

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.

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 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.

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]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part 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.

B. Emission standards:

(1) The owner or operator shall use best management and good operational or engineering practices to minimize emissions of VOC from produced water management units (PWMU).

(2) The owner or operator shall not allow any dumping 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. ~~control VOC emissions from each produced water management unit to less than two tons per year.~~

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 ~~rolling 12-month~~ total ~~of~~ 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~~2~~) 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 ~~and~~

(5~~3~~) comply with the monitoring requirements ~~in 20.2.50.112 NMAC~~of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each PWMU~~produced water management unit~~:

(a) ~~name or~~ unique identification number ~~of the unit and~~ and UTM coordinates of the PWMU ~~of the unit and county~~;

(b) ~~a description of~~ the best management and good operational or engineering practices used to minimize ~~release~~ emissions of VOC from~~at~~ the unit;

(c) the protocol, and the results of the sampling conducted in accordance with the protocol; and

(d~~c~~) a record of the ~~monthly rolling 12-month~~ annual total VOC emissions from each unit.

(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.
[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE ~~INFORMATION PRESUMPTION~~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~~, the source shall be presumed to be~~ 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 ~~unless and until the owner or operator provides credible evidence or information demonstrating otherwise~~.

~~**C.** If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~
~~[20.2.50.127 NMAC - N, XX/XX/2021]~~

HISTORY OF 20.2.50 NMAC: **[RESERVED]**

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123

July 14, 2021

Liz Bisbey-Kuehn
NMED Air Quality Bureau
525 Camino de los Marquez
Santa Fe, NM 87505
nm.methanestrategy@state.nm.us

RE: Oil and Gas Sector - Ozone Precursor Pollutants
Title 20 Chapter 2 Part 50

Solar Turbines Incorporated (Solar) appreciates the opportunity to comment on the May 6, 2021 proposed oil and natural gas regulation for ozone precursors.

Solar is a manufacturer of industrial combustion turbines (1000-32,000 hp). Solar's fleet includes more than 16,000 combustion turbines over 100 countries. Our domestic fleet consists of over 8000 combustion turbines in power generation, pipeline compressor, and mechanical drive applications.

Solar asks that the New Mexico Environmental Department (NMED) consider the following comments. Solar asks that the agency contact us if more information is necessary to explain any comment. Solar has been in contact with several of our New Mexico customers and the New Mexico Oil and Gas Association (NMOGA) that are also preparing comments to the proposal. We ask that the NMED pay special attention to the comments prepared by these gas turbine users.

Solar submitted comments on the draft proposal (dated 7/20/20) on September 2, 2020. Per the content of the May 6, 2021 proposed rule, the NMED did make several improvements to the draft in-line with Solar's initial comments. However, there are a few additional improvements that Solar requests the NMED make to the proposed rule to ensure more equitable treatment between existing reciprocating engines and turbines and to correct a technology availability/achievability assumption error carried over from the "cut and paste" of the Pennsylvania rule used as a template for the turbine emissions limits.

Summary of Requests:

1. Solar Turbines recommends the NMED adjust the NOx emission standard in the smallest turbine category in 20.2.50.113 Table 3 to match 40CFR60 Subpart KKKK emission standards for <50 MMMBtu/hr new, modified or reconstructed units accordingly.
2. Solar Turbines requests a compliance schedule for existing turbines tied to the timing of the next major overhaul or a compliance schedule similar to that as proposed for reciprocating engines in 20.2.50.13 B(3).
3. Solar Turbines recommends NMED remove all references to carbon monoxide (CO) from the proposed rule.

Request #1

Solar Turbines recommends NMED adjust the NOx emission standard in the smallest turbine category in 20.2.50.113 Table 3 to match 40CFR60 Subpart KKKK emission standards for <50 MMMBtu/hr new, modified or reconstructed units accordingly.

Solar appreciates the NMED raising the NOx level in the smallest turbine category for existing sources, however, the increase is not sufficient to support the existing fleet of Saturn 10 and Saturn 20 turbines. At the proposed 50 ppm NOx level for existing units and 25 ppm NOx for new units, in the 1-5000 hp range, many turbines would require the addition of add-on control, namely SCR. Solar does not believe the intent of the agency is to force these small turbines into very expensive SCR retrofits. A Dry Low NOx (DLN) retrofit is not available on the Saturn line of gas turbine. Water injection, theoretically, may be a technical option on some of the Saturn 20 installed fleet and able to meet the 50 ppm NOx. However, with water injection, the proposed CO level is only warrantable between 95-100% load. A CO level of 200 ppm is recommended to cover 80-95% operating loads. As stated, water injection is not a technical option for many of the Saturn units so SCR would be the only technically viable option for many installed Saturns. The availability, cost, and use of large volumes of deionized water (estimated 3.5MM gallons per year per Saturn 20), especially at the remote and unmanned sites, would need considerable evaluation.

As noted in our September 20, 2020 comment letter, NMED modeled the proposed ozone rule after Pennsylvania's GP-5 rule but did not adopt all of the applicability language with respect to existing sources. GP-5 does not impact pre-2013 units. In GP-5, units constructed on or after February 1, 2013, but prior to August 8, 2018 have to meet either 25 or 15 ppm NOx depending on their size. The NMED proposed rule impacts <u>all</u> existing units with no consideration for date of construction. Further background on the GP-5 rule development process is that there were no turbines in Pennsylvania in the 1000-5000 hp range installed on or after February 1, 2013, but prior to August 8, 2018 so no existing units were affected. When GP-5 was being developed Solar commented that the NOx emission standards in this size category are not technically achievable or commercially available from turbine manufacturers but since there were no affected units in Pennsylvania the PADEP, were not inclined to change the rule language. The situation becomes a problem when "cut and paste" into another states' program where there are affected units in the size category.

New Mexico has many existing turbines in the smallest size category that will be unable to meet the proposed NOx standards without add-on control. A higher emissions level, congruent with Subpart KKKK (150 ppm NOx for existing/reconstructed and 100 ppm NOx for new), will allow for DLN where it's available to be retrofit and allow the smaller turbines, for which DLN is not available, to continue to operate. Many, if not all, of the turbines that fall into this smallest category are Subpart GG (or pre-NSPS) turbines.

Solar recommends the limits for turbines ≥1000 and <5000 hp in Table 3 be modified from 50 ppm to 150 ppm NOx for existing turbines and the 25 ppm for new turbines be modified to 100 ppm NOx to match 40 CFR Subpart KKKK NOx levels.

To help New Mexico achieve their goal with the proposed rule and at the same time consider dry low NOx technology availability, Solar suggests altering the category boundary cutoff from 5000 bhp to 4000 bhp. Assuming NMED heeds the recommendation above to change

NOx to 150 ppm and 100 ppm for existing and new, respectively, also changing the category cutoff to 4000 bhp would place Solar Saturns and Centaur 40 4000s, for which there is no dry low NOx option, in the small category and the Centaur 40 4500 and 4700 ratings in the middle category for which there is a dry low NOx retrofit option available.

Request #2

Solar Turbines requests a compliance schedule for existing turbines tied to the timing of the next major overhaul or a compliance schedule similar to that as proposed for reciprocating engines in 20.2.50.113 B (2).

The header in Table 3 suggests a 2-year compliance timeline for existing turbines. Solar requests a compliance schedule tied to the timing of the next major overhaul or that turbines be treated similarly to reciprocating engines and be given a schedule similar to that in section 20.2.50.113 B (2). The NMOGA comment letter outlines a recommended compliance schedule for combustion turbines that mirrors the compliance schedule for reciprocating engines.

A 2-year timeline from the effective date of rule is unrealistic unless a major routine overhaul was already planned for that timeframe. Typical major overhaul cycles run every 3.5 to 4.5 years depending on the operating hours of the turbine. Note: to accommodate the emissions standards proposed in this rule it is anticipated, that in addition to a dry low NOx retrofit at time of overhaul, upgrades to the package, control system, fuel system, and other ancillary systems will be necessary.

Request #3

Solar Turbines recommends NMED remove all references to CO from the proposed rule.

Sections 20.2.50.6 and 20.2.50.112 A (2) and (3) clearly state that the scope and objective of the Part is to establish emissions standards for the specific ozone precursors: volatile organic compounds (VOC) and nitrogen oxides (NOx). As such, including emission standards, monitoring, recordkeeping, reporting, and testing requirements for CO should not be included in the rulemaking.

In the event that NMED does not remove all references to CO in this proposed ozone rule, Solar recommends a level of 25 ppm for new sources in all size categories.

The following “red-lined” version of Table 3 illustrates Solar’s suggested revisions to the proposed rule.

Table 3 – EMISSIONS STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards ~~no later than~~ ~~two years~~ at the time of the next major overhaul after ~~from~~ the effective date of this Part:			
Turbine Rating (bhp)	NOx (ppmvd @ 15% O2)	~~CO (ppmvd @ 15% O2)~~	NMNEHC (as propane, ppmvd @ 15% O2)
≥1,000 and <~~5,000~~4,000	~~50~~150	~~50~~	9
≥~~5,000~~4,000 and <15,000	50	~~50~~	9
≥15,000	50	~~50 or 93% reduction~~	5 or 50% reduction
For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon start-up:			
Turbine Rating (bhp)	NOx (ppmvd @ 15% O2)	~~CO (ppmvd @ 15% O2)~~	NMNEHC (as propane, ppmvd @ 15% O2)
≥1,000 and <~~5,000~~4,000	~~25~~100	~~25~~	9
≥~~5,000~~4,000 and <15,900	15	~~10~~ (recommend 25 ppm if not removed)	9
≥15,900	9 Uncontrolled or 2.0 with Control	~~10 Uncontrolled or 1.8 with Control~~ (recommend 25 ppm if not removed)	5

Please feel free to contact me at 858.694.6609 if you have any questions or need any additional information.

Sincerely,
Solar Turbines Incorporated
Leslie Witherspoon
Manager Environmental Programs
witherspoon_leslie_h@solarturbines.com

C:\LESLIE\CUST_QS AND PROJECTS\2020\20-095 NMED OZONE RULE\JULY 2021 SOLAR TURBINES COMMENT LETTER TO NM METHANE STRATEGY TITLE 20 CH 2 PART 50.DOC

Caprock Compressor Station Unit A-01: GE Model M3702R Turbine, 6,026 hp permitted capacity, circa 1957								
Cost Estimates assume the bank prime interest lending rate of 3.25% and a 20-year lifespan for SCR								
Kinder Morgan Cost Estimates			**NMED Low-end Estimates**			**NMED High-end Estimates**		
Base Case			**Base Case**			**Base Case**		
NO_X (lb/hr):	34.35	9/20/2020 KMI Stack Test	NO_X (lb/hr):	34.35	9/20/2020 KMI Stack Test	NO_X (lb/hr):	45.9	Permitted Emission Rate
NO_X (tpy):	11.51	KMI Estimates	NOX (tpy):	34.43	NMED – 2020 Title V EI Submittal	NO_X (tpy):	201	Permitted Annual Emissions
SCR			**SCR**			**SCR**		
NO_X Reduction:	66.2%	50 ppmv equivalent	NO_X Reduction:	70%	EPA-452/F-03-032	NO_X Reduction:	70%	EPA-452/F-03-032
NO_X (lb/hr)	11.62	1994 KMI Emissions test.	NO_X (lb/hr)	10.31		NO_X (lb/hr)	13.77	
NO_X (tpy)	3.89		NO_X (tpy)	10.33		NO_X (tpy)	60.3	
Building Modifications ($)		KMI Estimates	Building Modifications ($)		KMI Estimates	Building Modifications ($)		KMI Estimates
SCR Capital Investment ($)	7,180,921		SCR Capital Investment ($)	7,180,921		SCR Capital Investment ($)	7,180,921	
Total Capital Investment ($)	7,180,921		Total Capital Investment ($)	7,180,921		Total Capital Investment ($)	7,180,921	
Annualized TCI ($)	493,896	EPA Cost Manual	Annualized TCI ($)	493,896	EPA Cost Manual	Annualized TCI ($)	493,896	EPA Cost Manual
Annual O&M ($)	118,454	KMI Estimates	Annual O&M Costs ($)	118,454	KMI Estimates	Annual O&M ($)	118,454	KMI Estimates
Annual Costs ($)	612,350		Total Annual Costs ($)	612,350		Total Annual Costs ($)	612,350	
Emissions Reduction (tpy)	7.6		Emissions Reduction:	24.1		Emissions Reduction (tpy)	140.7	
Cost Effectiveness	$80,398/ton		Cost Effectiveness	$25,407/ton		Cost Effectiveness	$4,352/ton	

Caprock Compressor Station Unit A-02: GE Model M3572R Turbine, 4,879 hp permitted capacity, circa 1958								
Cost Estimates assume the bank prime interest lending rate of 3.25% and a 20-year lifespan for SCR								
KMI Cost Estimates			**NMED Low-end Estimates**			**NMED High-end Estimates**		
Base Case			**Base Case**			**Base Case**		
NO_X (lb/hr):	16.83	9/29/2000 KMI Stack Test	NO_X (lb/hr):	16.83	9/20/2020 KMI Stack Test	NO_X (lb/hr):	39.3	Permitted Emission Rate
NO_X (tpy):	29.64	KMI Estimates	NOX (tpy):	62.68	NMED 2019-20 Title V EI Submittal	NO_X (tpy):	172.1	Permitted Annual Emissions
SCR			**SCR**			**SCR**		
NO_X Reduction:	56%	50 ppmv equivalent	NO_X Reduction:	70%	EPA-452/F-03-032	NO_X Reduction:	70%	EPA-452/F-03-032
NO_X (lb/hr)	7.38 lb/hr	1994 KMI Emissions test.	NO_X (lb/hr)	5.05		NO_X (lb/hr)	11.79	
NO_X (tpy)	13.0		NO_X (tpy)	18.8		NO_X (tpy)	51.63	
Building Modifications ($)		KMI Estimates	Building Modifications ($)		KMI Estimates	Building Modifications ($)		KMI Estimates
SCR Capital Investment ($)	11,430,361		SCR Capital Investment ($)	11,430,361		SCR Capital Investment ($)	11,430,361	
Total Capital Investment ($)	11,430,361		Total Capital Investment ($)	11,430,361		Total Capital Investment ($)	11,430,361	
Annualized TCI ($)	786,167	EPA Cost Manual	Annualized TCI ($)	786,167	EPA Cost Manual	Annualized TCI ($)	786,167	EPA Cost Manual
Annual O&M ($)	128,097	KMI Estimates	Annual O&M Costs ($)	128,097	KMI Estimates	Annual O&M ($)	128,097	KMI Estimates
Annual Costs ($)	914,265		Total Annual Costs ($)	914,265		Total Annual Costs ($)	914,265	
Emissions Reduction (tpy)	16.6		Emissions Reduction:	43.9		Emissions Reduction (tpy)	120.5	
Cost	$54,935/ton		Cost	$20,837/ton		Cost	$7,589/ton	

METHANE MITIGATION ROADMAP

NMOGA

NEW MEXICO OIL AND GAS ASSOCIATION

NMED Rebuttal Exhibit 7

NMED Rebuttal Exhibit 7

INTRODUCTION

NMOGA's operators have undertaken a proactive approach to both reduce methane and VOC emissions and capture as much natural gas as possible. To accomplish this, NMOGA's operators have turned to science, innovation, and collaboration to prevent waste, to greatly reduce methane and VOC emissions, and to improve air quality, all while creating jobs for New Mexicans. We are pushing forward, investing in technological advancements, and collaborating with regulatory agencies to achieve this goal.

NMOGA supports a practical, cost-effective methane and VOC mitigation strategy, and considers this as a win for all involved. This NMOGA methane document includes the New Mexico oil and gas industry's four highest reported sources: (1) equipment leaks, (2) storage vessels, (3) pneumatic devices, and (4) liquids unloading operations. We also provide regulatory suggestions and considerations that are based on sound science from peer-reviewed data and are effective in reducing methane and VOC emissions to improve air quality.

Upstream of the gas plant, which is production and gathering/boosting operations, methane and VOC are co-emitted. VOCs and methane are combined stream of gas until the gas stream reaches the gas plant, where most VOCs are separated from the natural gas, which is then primarily methane. Any control upstream of the gas plant that reduces VOC also controls methane.

SUMMARY OF REGULATORY CONSIDERATIONS AND SUGGESTIONS

Effective methane and VOC reduction regulations should be based on (1) pertinent regulatory applicability thresholds, (2) practical implementation of controls based upon broadly acceptable methods for establishing costs and emissions benefits, (3) good engineering practices, (4) applicable and credible science, and (5) reasonable boundaries for recordkeeping.

NMOGA supports regulatory flexibility to avoid a “one size fits all” regulatory scheme. For example, New Mexico’s two major oil and gas producing basins, the San Juan (Northwest) and Permian (Southeast), have profoundly different production characteristics. Wells in the San Juan primarily produce drier gas, which may result in the production of small amounts of condensate. Also, San Juan wells are generally both lower producers and older compared to horizontal wells in the Permian, which consequently results in lower emissions on a per facility basis. The Permian basin in Southeast New Mexico is primarily an oil producing basin, with associated gas production. In the Permian basin, wells tend to have higher initial production before entering into a prolonged period of declining production. The production profiles of each basin are so vastly different, which in turn dictates the types of operations and equipment used. These differences should be recognized when examining any potentially prescriptive standards.

With appropriate flexible regulatory language to reduce methane and VOC emissions, NMOGA supports for existing equipment: (1) annual leak detection and repair with exemptions for low producing wells and facilities that are not required to obtain a Notice of Intent, (2) storage vessel control requirements with appropriate thresholds, (3) phase-out of high-bleed pneumatic controllers unless required for safety function; and (4) onsite monitoring of manual liquids unloading operations. NMOGA requests that NMED recognize that many equipment sources are already subject to controls under federal NSPS OOOO and OOOOa regulations and an additional layer of state regulations will impose further requirements and costs without attendant emission reductions.

NEW MEXICO SPECIFIC DATA FROM EPA GREENHOUSE GAS REPORTING RULE

The Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program

(GHGRP) requires that operators submit estimates of their emissions annually using EPA prescribed methodology. Reporting is required if a facility's total GHG emissions exceed the reporting threshold of 25,000 mtCO2e per geographic basin. Because some facilities do not have GHG emissions that exceed the reporting threshold the dataset is not a comprehensive inventory. The EPA dataset does provide useful equipment comparison analysis and provides emission trends for the reported population. Nationally, reported oil and gas methane emissions declined by about 14% while oil and gas production increased more than 80% and 51% respectively from 1990 to 2017. These large methane reductions during an increase in oil and gas drilling activity are driven by a combination of voluntary/good operating practice implementation, and state and federal rule and permit actions that reduce methane emissions from the oil and gas sector.

Also, a recent study conducted by researchers at National Oceanic and Atmospheric Administration's Boulder, Colorado office in collaboration with the University of Colorado was published in Geophysical Research Letters. The study analyzed atmospheric methane (CH4) measurements from 20 North American sites that included both airplane and surface samples found in the NOAA Global Greenhouse Gas Reference Network (GGGRN) from 2006 to 2015. The study concludes that not only have there been no large increases in U.S. methane emissions over the last decade, but previous studies have significantly overestimated these emissions from U.S. oil and natural gas production, overestimating methane emissions volumes by as much as 10 times.

[1]For oil and gas production, a facility is basin-wide production equipment

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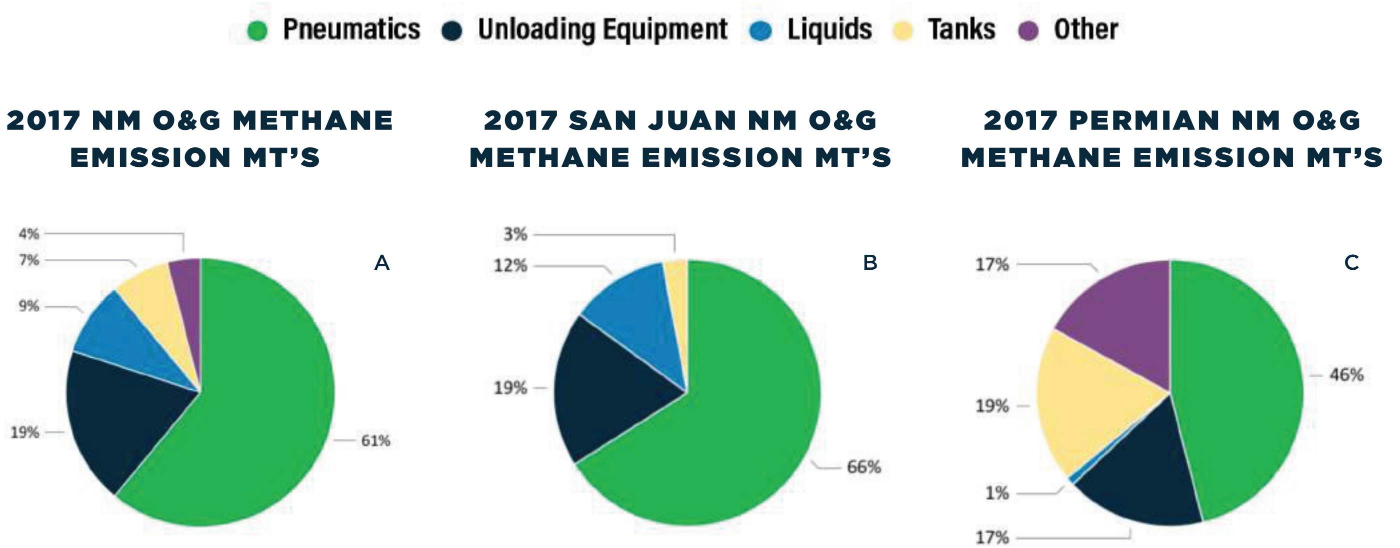
NEW MEXICO SPECIFIC DATA FROM EPA GREENHOUSE GAS REPORTING RULE

The data represented below reflects an analysis using the EPA GHGRP reported data from New Mexico oil and gas operations. The data is reported by basin, not by state, and includes reported methane emissions from the Northwest New Mexico San Juan Basin and the Southeast New Mexico Permian Basin. Both basins cross state boundaries into other states (Colorado for the San Juan and Texas for the Permian) and GHGRP emissions reported for source types at the basin level without specific location information are allocated amongst the relevant states based on GHGRP reported well counts in each state.

For source types with location (county and state) information, reported emissions are directly aggregated. In 2017, scaled-up GHGRP reported methane emissions in NM totaled 205,470 metric tonnes (MT's). In 2011, 50% of wells in the Permian basin were included in GHGRP reporting, and by 2017 coverage increased to 72%. In the San Juan Basin, over 85% of wells have been included in GHGRP reporting since 2011. For the production segment, we have scaled all emissions in each year up to the total well count reported by the New Mexico Oil Conservation Division (NMOCD). For the Gathering and Boosting segment, a) companies with facilities greater than 25,000 MT's are reported, and b) companies with facilities less than the 25,000 MT's (small source of methane emissions) are not reported. GHGRP reported emissions are shown.



Panel A - NM methane emissions by source; Panel B: Permian basin methane emissions by source;
Panel C - SJ basin methane emissions by source

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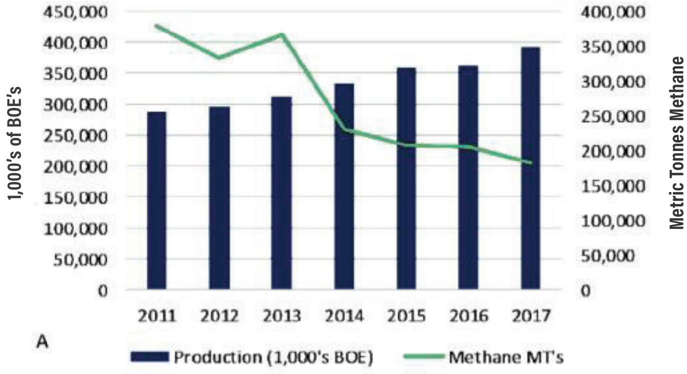
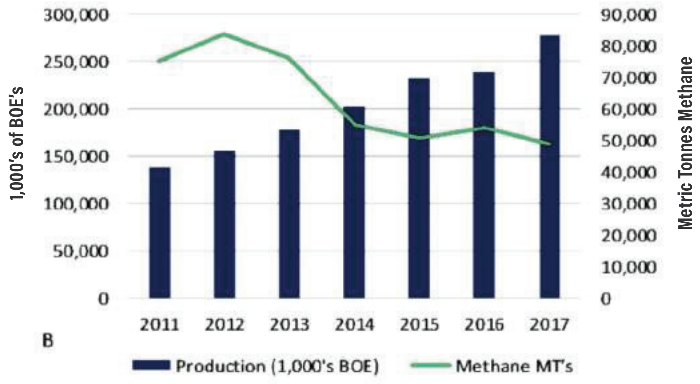
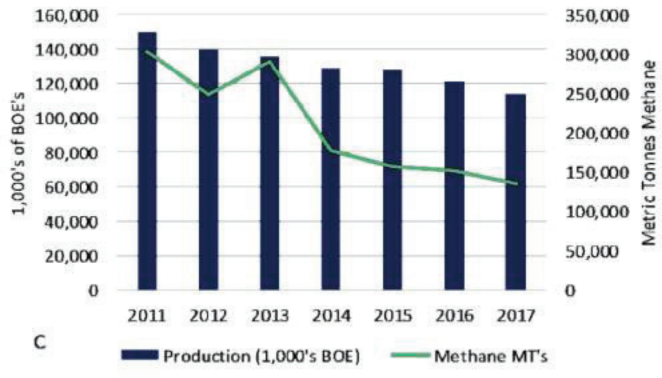
NEW MEXICO - OIL AND GAS PRODUCTION & METHANE EMISSIONS



PERMIAN BASIN NM - OIL AND GAS PRODUCTION & METHANE EMISSIONS



SAN JUAN BASIN NM - OIL AND GAS PRODUCTION & METHANE EMISSIONS



PANEL A:
NEW MEXICO PRODUCTION AND METHANE EMISSIONS;

PANEL B:
PERMIAN BASIN NM PRODUCTION AND METHANE EMISSIONS;

PANEL C:
SJ BASIN PRODUCTION AND METHANE EMISSIONS

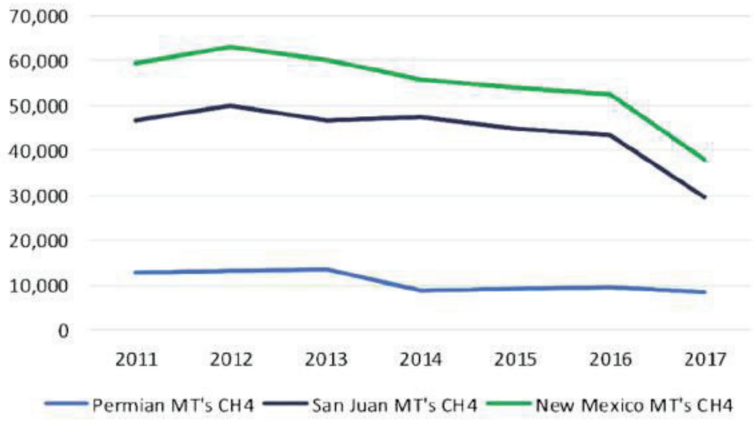
NMED Rebuttal Exhibit 7

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

4.1. FUGITIVE EMISSIONS

TRENDS - EPA GHGRP

NM EQUIPMENT LEAKS
MT'S METHANE EMISSIONS



Description

All production facilities contain numerous equipment components such as valves, flanges, threaded connections, tubing connections, open-ended lines (OELs), and pump seals which are manufactured and installed in ways intended to contain gases or liquids. Although these equipment components are designed to be gas tight, over time leaks can occur. The leaks (emissions) from these components are called fugitive emissions[2]. Fugitive emissions do not include equipment that is designed to vent or release emissions as part of normal operations. Fugitive emissions result from changes in pressure, temperature or mechanical stresses or when seals and gaskets are not fitted or deteriorate over time.

Sources of fugitive emissions are generally detected quickly without advanced detection tools. These events are usually detected by observable changes in operating parameters (i.e. Supervisory Control and Data Acquisition (SCADA) system detection, change in sales volume at the meter, compressor shut down), or by operators conducting routine inspections using sight, sound or smell.

[2] Where devices are designed to vent as part of normal operations, such as natural gas-driven pneumatic devices or uncontrolled storage vessels, the natural gas and associated VOC emissions are not considered a fugitive emission. These emissions are covered in other portions of this document.

NMED Rebuttal Exhibit 7

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

Leak detection and repair (LDAR) programs employ specialized detection equipment to detect fugitive emissions, which also sometimes include audio, visual, and olfactory observations, generally target sources of fugitive emissions. The most commonly used leak detection equipment is an optical gas imager, but companies also use handheld “sniffers” (portable detectors) and Tunable Diode Laser Absorption Spectroscopy devices. The detection technology space has received significant investment over the past several years, including the U.S. Department of Energy’s MONITOR program[3]. The results of this investment are just beginning deployment and may be widely available at commercial scale in the near term.

Regulatory Considerations and Suggestions

- NMOGA supports the development of a cost-effective LDAR program for existing facilities, as long as these avoid duplication with existing federal programs, such as the LDAR provisions of NSPS OOOOa and NSPS KKK.

- A recent review of NSPS OOOOa leak survey data indicates that annual inspection frequency is appropriate for non-marginal well sites or facilities[4]. Data from various federal and state and inspection programs, including Colorado, demonstrates that the initial component leak rate from initial inspection surveys, show a significantly lower number of leaks than previously assumed. For example, an API analysis of initial NSPS OOOOa inspections showed that only 0.4% of components are found to be leaking during the initial inspection. West Slope Colorado data showed a 0.74% component leak rate for sites with emissions less than 6 tons per year VOC.

- Additionally, the number of leaks found in inspections at subject facilities in Colorado show a 52% decrease in the number of leaks from 2015 to 2017, while the number of facilities inspected increased by 9%.

NMED Rebuttal Exhibit 7

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

▪ Marginal wells (< 15 barrels of oil equivalent per day) should be excluded from the LDAR program. Marginal wells, by their nature, are lower producing and generally requires less equipment with fewer components. In fact, data has indicated that leak detection is most effective for newer systems to ensure that all componentry and equipment is tightened from the outset and that the frequency of detection lowers over time. These factors mean that the cost of each marginal well LDAR survey often outweighs the benefits of the potential emission reductions and can threaten their financial viability. In the oil-and-gas control technique guidelines, EPA expressly recognized that fugitive emissions at low-production sites are inherently low and thus included an exemption from the LDAR program for well sites with an average production of less than 15 barrels of oil equivalent per day. Unless and until additional, comprehensive and conclusive data has been collected to suggest that marginal wells warrant inclusion in an LDAR program, these wells should be excluded. Leak data on marginal wells is very limited and warrants further study through objective, transparent, repeatable, and reliable emissions measurements. The sample size of the current data set is too small to provide conclusive results. Proper inspection methods and associate frequency must be informed by well-established data that can correlate production and emissions. Other factors that must be weighed are type and quantity of equipment, frequency of episodic emission events, equipment age/condition, and absolute contribution to total emissions. The Department of Energy is co-funding such a study titled "Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells" being conducted by GSI Environmental Inc.

▪ Wellhead only locations should not be included in the LDAR program due to very limited equipment on location, consistent with NSPS OOOOa. Facilities that do not require a Notice of Intent similarly have limited equipment and should be exempt from a LDAR program. Uncontrolled equipment, such as low emitting tanks, would also not benefit from an LDAR program as emissions will fall below the allowable permit limits, with or without an inspection program.

NMED Rebuttal Exhibit 7

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

- Maximum flexibility should be afforded to owners or operators to utilize new technologies for identifying leaks. Industry has partnered with academia and NGOs to explore innovative technologies to cost-effectively and accurately locate methane emissions associated with oil and gas locations. Low-cost sensing systems are needed to reduce methane leaks, minimize safety hazards and promote more efficient use of our domestic resources. Various field tests are being deployed to demonstrate the performance capabilities of such sensing technologies and accelerate the commercialization of such. It is imperative that regulatory agencies unlock the benefits of these emerging technologies by providing a flexible regulatory construct. New Mexico has a unique opportunity to set the stage to encourage adoption of innovative technologies.

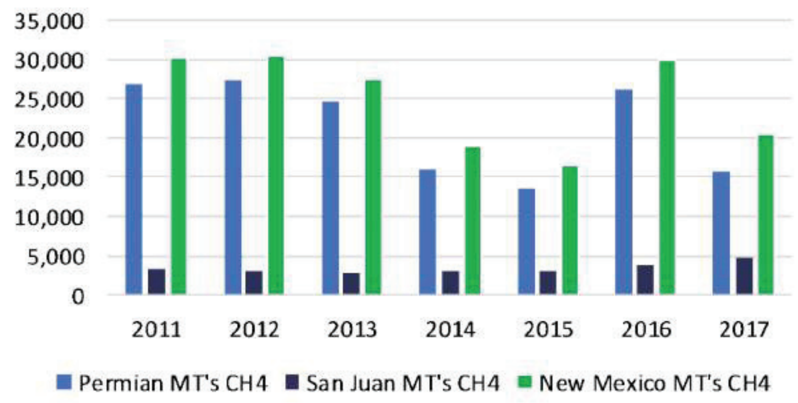
- Emerging detection technologies may lead to variable work practices. For example, sensors flown on aircraft may have a higher leak threshold but will cover a wider geographical area and therefore can be more cost-effectively conducted at a greater frequency. Enabling new technologies may also require flexibility in work practices, as long as overall emissions reductions are equivalent.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

4.2. STORAGE TANKS

TRENDS - EPA GHGRP

NM METHANE METRIC TONNES FROM TANKS



Description

Storage vessels in the production sector of the oil and natural gas industry are used to hold a liquids including crude oil, condensates, and produced water. Storage vessels can be installed a single unit or in grouping of similar or identical vessels, commonly referred to as a tank battery. Before being routed to a storage vessel, production liquids are passed through the separation equipment, where most of the gas entrained in the liquids is separated and routed to a sales line or control device. The liquids are then directed to a storage vessel where they are temporarily stored before being transported off-site. Although the majority of gases are removed from the liquids during the separation process, small concentrations of gas remain and will "flash" off when the liquids reach storage vessels operating at atmospheric pressure. Depending on a site's configuration, vapors that accumulate in the space above the liquid level in storage vessels may be routed to a gas sales line via a process unit such as a vapor recovery unit, if gas volumes are sufficient, or control device such as a vapor combustion device or flare.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

Regulatory Considerations and Suggestions

- NMOGA supports storage tank equipment control requirements for existing facilities not already subject to NSPS OOOO/OOOOa with appropriate thresholds. American Petroleum Institute's December 4, 2015 comments to EPA on the draft Control Techniques Guidelines suggests that a 15 tons per year VOC threshold is appropriate as existing source retrofits are more costly than controls on a new source. The throughput impacts the ability of the control equipment to function effectively. As noted in EPA's OOOO/OOOOa, requiring controls for new storage tanks below a certain VOC threshold may not be effective. For existing storage tanks, the control threshold will be even higher due to the additional cost to retrofit the equipment.

- It should be noted that many existing storage vessels are currently subject to controls under NSPS OOOO/OOOOa. In New Mexico, the enforceable state program (GCP Oil and Gas) allows operators to account for emissions reductions processes when calculating potential to emit to determine NSPS OOOO/OOOOa applicability for new storage vessels. EPA expressly allows for operators to account for enforceable limitations under state programs to prevent operators from being subject to duplicative requirements under state and federal law. To avoid duplication, storage vessels should only be required to comply with either NSPS OOOO/OOOOa or the state program, not both.

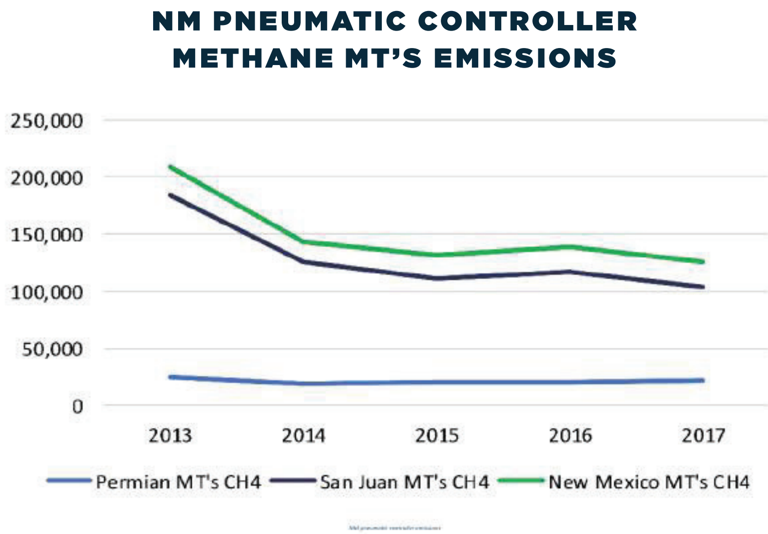
- The economics and technical feasibility of replacing or retrofitting existing storage vessels and associated equipment warrants a layered analysis, incorporating costs, timeframes, types of production, geographic location, and other considerations. Any storage vessels not currently subject to OOOO/OOOOa which are replaced due to new state regulation or due to reaching end of usable life will be subject to OOOO/OOOOa. NMOGA is currently exploring these considerations.

- Many existing storage vessels at older facilities were not designed for utilizing control devices as it can result in inherent safety risks by compromising tank integrity and causing tank over pressurization. Remaining useful life should be considered in any regulation.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

4.3. PNEUMATIC CONTROLLERS

TRENDS - EPA GHGRP



Description

The oil and natural gas industry uses a variety of process control devices to operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate. Natural gas powered 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 and may be actuated using pressurized natural gas (natural gas-driven)[5]. Natural gas driven pneumatic devices are a direct source of methane emissions.

Natural gas driven pneumatic controllers are classified by the EPA in three categories:

- Continuous High Bleed: These controllers vent continuously at a rate of over 6 scf/hour per manufacturer specifications.
- Continuous Low Bleed: These controllers vent continuously at a rate of less than 6 scf/hour per manufacturer specifications.
- Intermittent Vent: These controllers vent only when actuating. Depending on the type of service or operation the controller is in, it can actuate only a few times a year, or multiple times per hour.

[5] https://www.spe.org/media/filer_public/35/05/3505095e-314c-4acb-94b5-893415e00df1/19_pr172505.pdf

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THE FOUR MOST REPORTED SOURCES OF EMISSIONS

Regulatory Considerations and Suggestions

- NMOGA supports phasing out of continuous, gas powered, high bleed pneumatic controllers as there are commercially proven, cost-effective alternatives available. Sufficient time (e.g., 3 years) for manufacturers of alternatives to stock enough supply is necessary.

- For some replacement or retrofit activities, it is necessary to conduct such work during a turnaround.

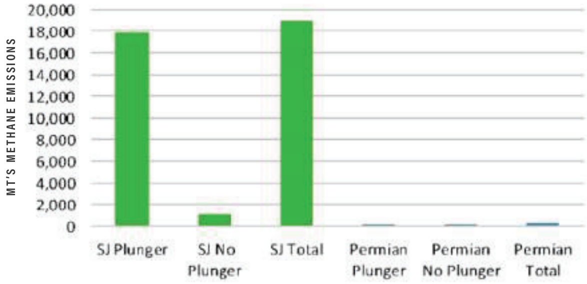
- It is not practical to eliminate use of all natural gas driven pneumatic controllers. Some pneumatic controllers are critical for operational integrity and safety, and must be able to operate reliably. In areas without access to electricity, or on small sites where air compression is not economically feasible, natural gas driven controllers are needed. Also, in areas where electricity supply may be regularly interrupted due to third party electrical reliability issues, natural gas driven pneumatics provide a critical role in allowing for safe and consistent operations.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

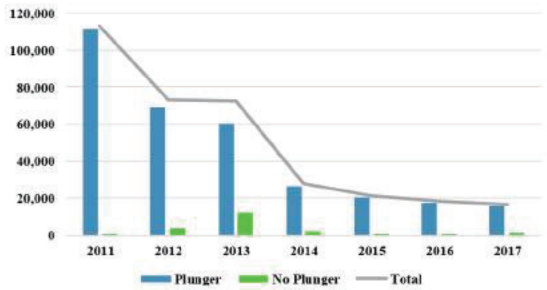
4.4. WELL MAINTENANCE AND WELL LIQUIDS UNLOADING

EQUIPMENT SPECIFIC TRENDS - EPA GHGRP

2017 NEW MEXICO LU VENTING MT'S METHANE EMISSIONS



GHGRPNM - MT'S CH4 LU VENTING



Description

Managing wellbore liquid build-up in 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 goes down, wellbore (tubing) velocity decreases, and liquid loading begins to occur in the wellbore. Liquid loading begins when the velocity up the production string is not sufficient to drag liquids up the wellbore. While pressure is a factor, it is generally velocity, not pressure, which causes liquids to accumulate in the wellbore (i.e., "to load"). Gas well unloading is a complex field of engineering where a large number of different technologies, tools and practices are matched to individual well characteristics at each stage of its lifecycle to most efficiently manage liquids and maintain economic production. No single technique will be adequate or appropriate across the full lifecycle of a well.

NMED Rebuttal Exhibit 7

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

As a well moves through its lifecycle, the appropriate approach to managing liquids changes as shown in Figure 1 below. New wells typically have production rates and flowing velocity high enough that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and consequent velocity declines and eventually reaches a point where liquid loading is an issue. The time this takes to occur is dependent on the reservoir characteristics and varies from well to well. At the onset of liquid unloading, techniques that rely on the reservoir energy are typically used. These include:

- Intermitting: Shutting in a well for a period of time to allow the reservoir to "refill" the pressure and the volume "void" in the near-wellbore reservoir. When the well is restarted the production rate and velocity are higher and the well can "unload" liquids through the normal production route to sales;

- Velocity strings: Installing a smaller diameter tubing string in the well that increases the flow velocity at a given production rate sufficiently to drag liquids up the wellbore and prevent liquid loading. Due to the trade-off between higher flowing friction in smaller diameter tubing and increased velocity the practical lower diameter limit is approximately 1 inch;

- Surfactants and foaming agents: Introducing surfactants and foaming agents to the bottom of a well (various techniques are used) creates foam with lower specific gravity which enables liquids to be carried up the wellbore at lower velocities;

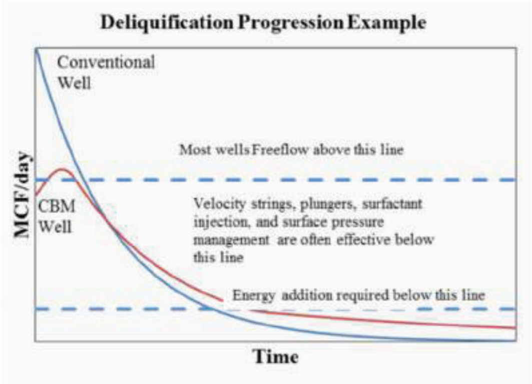
- Artificial lift: Installing a plunger lift system that changes the dynamic for removing liquids from velocity to differential pressure between the bottom-hole and the surface/gas collection line; and

- Additional compression: Installing wellhead compression that lowers the surface back-pressure on a well, increases production rate and flowing velocity, and increases the differential pressure between the reservoir and the collection/sales line.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

These techniques can be used individually or in combination to manage wellbore liquids and maintain production.

FIGURE 1: DELIQUIFICATION PROGRESSION EXAMPLE



Eventually a well will reach a point where the reservoir energy is insufficient to remove the liquids from the well and adding energy to the well is necessary to continue production. Common approaches are to install a pump in the well or install a gas lift system. Installation of a system to add energy to a well is an economic decision based on whether the continuing production warrants the costs of installing and operating a pump or gas lift system. Reservoir engineers and operators must have the flexibility to employ the appropriate tools at the appropriate times to manage wellbore liquids.

THE FOUR MOST REPORTED SOURCES OF EMISSIONS

Regulatory Considerations and Suggestions

EPA concluded for NSPS OOOOa that regulating venting and emissions associated with managing wellbore liquids is not feasible due to the complexity of managing well production. Adoption of Best Management Practices allows operators to determine the most efficient way to reduce liquids unloading emissions. Practices such as monitoring manual liquids unloading can result in emissions reductions. Deliquification/liquid-unloading and venting are not synonymous terms. Liquids can and are routinely removed from gas wells without venting. About 85% of the gas wells in the U.S. have low enough production rates to have liquid loading issues, and only about 13% have liquids unloading venting to assist liquid removal in 2012 (gross up of GHGRP data).

The key to minimizing venting while maintaining liquid removal is understanding and using the reservoir energy dynamics - in particular, build-up of pressure. Venting wells “waste” reservoir energy, which can be used to manage liquids and maintain production.

Many technologies are not suitable for certain wells or in certain areas. Gas to liquid ratio of each well affects feasibility. Appropriate technologies and economic feasibility will vary during the lifecycle of a well, particularly as production declines. Here are some examples of considerations for various options:

- Artificial Lift: Use of any specific artificial lift technology for moving liquids off well where reservoir pressure is not sufficient to move it naturally is dependent on well type, reservoir conditions and cost of technology.

- Plunger lifts: Difficult in areas that produce significant amounts of water

- Pump jacks and compressors: Greater surface disturbance and increased noise

- Rod pump/progressing cavity pumps: Not effective on deep and deviated wells, increased surface disturbance and greater energy requirements

- Electric operated equipment: May require generators creating additional emissions

SUMMARY OF FEDERAL AIR QUALITY REGULATIONS THAT APPLY TO THE OIL AND GAS SECTOR IN NEW MEXICO *

40 CFR part and subpart	Title of subpart	Potentially affected sources in the oil and natural gas production and natural gas processing segments of the oil and natural gas sector	Location
40 CFR part 63, subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.	Process heaters	http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.14.63.ddddd&rgn=div6
40 CFR part 63, subpart ZZZZ[6]	Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	Reciprocating Internal Combustion Engines.	http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;rgn=div6;view=text;node=%3A14.0.1.1.1.1;idno=40;sid=e94dcfde4a04b27290c445a56e635e58;cc=ecfr
40 CFR part 60, subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.	Compression Ignition Internal Combustion Engines.	http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.iiii&rgn=div6
40 CFR part 60, subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.	Spark Ignition Internal Combustion Engines.	http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.jjjj&rgn=div6
40 CFR part 60, subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.	Fuel Storage Tanks	http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.k_0b&rgn=div6
40 CFR part 60, subpart OOOO and OOOOa (final).	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.	Storage Vessels, Pneumatic Controllers, Compressors (Reciprocating and Centrifugal), Hydraulically Fractured Oil and Natural Gas Well Completions, Pneumatic Pumps and Fugitive Emissions from Well Sites and Compressor Stations.	http://www.epa.gov/airquality/oilandgas/actions.html
40 CFR part 63, subpart HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.	Glycol Dehydrators	http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.11.63.hh&rgn=div6
40 CFR part 60, subpart KKKK[7] ...	Standards of Performance for New Stationary Combustion Turbines.	Combustion Turbines	http://www.ecfr.gov/cgi-bin/text-idx?SID=4090b6cf5eea5cb67940a80906ff09a2&mc=true&node=sp40.7.60.kkkk&rgn=div6

* THIS LIST DOES NOT INCLUDE PERMITTING REQUIREMENTS.

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APPENDIX: NARRATIVE OF EPA OIL AND GAS REGULATIONS HISTORY

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO2) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO2 emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO2 emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels.

In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards, NSPS OOOO, to regulate both GHG and VOC emissions across the oil and natural gas source category. In NSPS OOOOa, the EPA finalized: (1) GHG standards for the emission sources that were regulated only for VOC under NSPS OOOO (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants); and (2) GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the prior NSPS OOOO (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

Finally, although not regulated under the oil and natural gas NSPS (OOOO and OOOOa), stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

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Oil and Natural Gas Sector
Liquids Unloading Processes

Report for Oil and Natural Gas Sector

Liquids Unloading Processes

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

NMED Rebuttal Exhibit 8

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PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:
www.epa.gov/airquality/oilandgas/whitepapers.html

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater air emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on air emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

In new gas wells, there is generally sufficient reservoir pressure to facilitate the flow of water and hydrocarbon liquids to the surface along with produced gas. In mature gas wells, the accumulation of liquids in the well can occur when the bottom well pressure approaches reservoir shut-in pressure. This accumulation of liquids can impede and sometimes halt gas production. When the accumulation of liquid results in the slowing or cessation of gas production (i.e., liquids loading), removal of fluids (i.e., liquids unloading) is required in order to maintain production. Emissions to the atmosphere during liquids unloading events are a potentially significant source of VOC and methane emissions.

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, common courses of action to improve gas flow include (U.S. EPA, 2011):

- Shutting in the well to allow bottom hole pressure to increase, then venting the well to the atmosphere (well blowdown, or "blowing down the well"),

- Swabbing the well to remove accumulated fluids,
- Installing a plunger lift,
- Installing velocity tubing, and
- Installing an artificial lift system.

Blowing down the well involves the intentional manual venting of the well to the atmosphere to improve gas flow, whereas the use of a plunger lift system uses the well's own energy (gas/pressure) to lift liquids from the tubing by pushing the liquids to the surface by the movement of a free-traveling plunger ascending from the bottom of the well to the surface. The plunger essentially acts as a piston between liquid and gas. Use of a plunger lift often minimizes and sometimes eliminates the need for blowing down the well.

Because of the potential for substantial VOC and methane emissions occurring during liquids unloading at natural gas wells, there are an increasing number of studies on emissions from natural gas well liquids unloading events. These studies of liquids unloading practices attempt to quantify emissions on a well specific, regional and national level and often take into account the use of available mitigation techniques, such as plunger lifts. This document provides a summary of the EPA's understanding of VOC and methane emissions from natural gas production liquids unloading events, available liquids unloading and emission mitigation techniques, the relative magnitude of emissions associated with the respective techniques and the efficacy and prevalence of those techniques in the field. Section 2 of this document provides our understanding of emissions from liquids unloading events, and Section 3 provides our understanding of available liquids unloading and emissions mitigation techniques. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist us with obtaining a more comprehensive understanding of liquids unloading VOC and methane emissions and emission mitigation techniques for the liquids unloading process.

2.0 OIL AND NATURAL GAS SECTOR LIQUIDS UNLOADING AVAILABLE EMISSIONS DATA AND EMISSIONS ESTIMATES

Given the potential for significant emissions from liquids unloading, there have been several information collection efforts and studies conducted to estimate emissions and available emission mitigation techniques. Some of these studies are listed in Table 2-1, along with an indication of the type of information contained in the study (i.e., activity level, emissions data, mitigation techniques).

Table 2-1. Summary of Major Sources of Liquids Unloading Information

Name	Affiliation	Year of Report	Activity Data	Emissions Data	Mitigation Techniques
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	U.S. Environmental Protection Agency	2013	Sub-basin	X	X
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (2014 GHG Inventory) (U.S. EPA, 2014)	U.S. Environmental Protection Agency	2013	Regional	X	X
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012)	American Petroleum Institute (API)/America's Natural Gas Alliance (ANGA)	2012	Regional	X	X
Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	9 Liquids Unloading Events	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)	ICF International (Prepared for the Environmental Defense Fund)	2014	Regional	X	X

A more-detailed description of the data sources listed in Table 2-1 is presented in the following sections, including how the data may be used to estimate national VOC and methane emissions from liquids unloading events.

2.1 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 greenhouse gas (GHG) data for Petroleum and Natural Gas Systems[1] collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other datasets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility[2] in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 metric tons carbon dioxide equivalent (CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

The liquids unloading source emissions reported under the GHGRP include emissions from facilities that have wells that are venting, including those wells that vent during plunger lift operation. Liquids unloading techniques that do not involve venting are not reported. The total reported methane emissions in 2012 for liquids unloading were approximately 276,378 metric tons (MT). Facilities were given the option among three methods for calculating emissions from liquids unloading. The first calculation method involved using a representative well sample to calculate emissions for both wells with and without plunger lifts. The second and third

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[1] The implementing regulations of the Petroleum and Natural Gas Systems source category of the GHGRP are located at 40 CFR Part 98 Subpart W.

[2] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

calculation methods provided engineering equations for wells with plunger lifts and without plunger lifts.

Of the 251 facilities that reported emissions for well venting for liquids unloading, 120 facilities reported using Best Available Monitoring Methods (BAMM) for unique or unusual circumstances. Where a facility used BAMM, it was required to follow emission calculations specified by the EPA, but was allowed to use alternative methods for determining inputs to calculate emissions. These inputs are the values used by facilities to calculate equation outputs or results. Table 2-2 shows the activity count and reported emissions for the different calculation methods.

Table 2-2. Greenhouse Gas Reporting Program 2012 Reported Emissions from Liquids Unloading (U.S. EPA, 2013)

Calculation Method	Number of Facilities Reporting[a]	Number of Wells Venting During Liquids Unloading	Number of Wells Venting that are Equipped With Plunger Lifts	Reported CH_4 Emissions (MT)[b]
Method 1: Direct Measurement of Representative Well Sample	42	10,024	7,149	112,496
Method 2: Engineering Calculation for Wells without Plunger Lifts	188	23,536	0	71,593
Method 3: Engineering Calculation for Wells with Plunger Lifts	132	25,103	25,103	92,289
Total	251	58,663	32,252	276,378

[a] Total number of facilities is smaller than the sum of facilities from each method because some facilities reported under both Method 2 and Method 3.
[b] The reported CH_4 MT CO_2e emissions were converted to CH_4 emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.2 API/ANGA 2012 Survey Data (API and ANGA, 2012)

The API/ANGA 2012 Survey Data includes a dataset from over 20 companies covering over 90,000 gas wells, including approximately 59,000 wells that conducted liquids unloading operations. This study sample population includes representation from most of the geographic regions of the country as well as most of the geologic formations currently developed by the industry. The study provides estimated methane emissions from liquids unloading for 5,327 wells that were calculated based on well characteristics such as well bore volume, well pressure, venting time, and gas production rate and using 40 CFR part 98, subpart W engineering equations. These emissions estimates and the activity data used to calculate the estimates are presented in Table 2-3.

Table 2-3. API/ANGA Study Liquids Unloading Emissions Estimates (API and ANGA, 2012; pg. 14)

Mid-Level Survey Data	
Total number of wells with plunger lift (42,681 in sample)	11,518
Total number of wells without plunger lift (42,681 in sample)	31,163
Number of plunger equipped wells that vent (42,681 in sample)	2,426 (21.1%)
Number of non-plunger equipped wells that vent (i.e., wells performing blowdowns)(42,681 in sample)	2,901 (9.3%)
Total annual volume gas vented for venting wells	1,719,843,596 standard cubic feet (scf) gas/year
Calculated volume vented gas per venting well	322,854 scfy gas/well
Calculated methane volume vented per venting well	254,409 scfy CH_4/well
Calculated National Well Data	
Calculated national number of wells with plunger lift that vent for unloading	36,806
Calculated national number of wells without plunger lift that vent for unloading (i.e., wells performing blowdowns)	28,863
National Emission Calculations	
Total gas venting for liquids unloading volume (scaled for national wells)	21,201,410,618 scf gas/yr
Total methane venting for liquids unloading (scaled for national wells)	16,706,711,567 scf CH_4/yr
Total liquid unloading vented methane (scaled for national wells)	319,664 MT CH_4/yr

The authors of the study made the following conclusions:

- The 2012 GHG Inventory emissions estimates for liquids unloading were overestimated by orders of magnitude. The API/ANGA Survey data indicated a lower percentage of gas wells that vent for liquids unloading and a shorter vent duration.
- The emissions from liquids unloading are not specific to only conventional wells, but can be for any well depending on several technical and geological aspects of the well.
- Although most wells do not require liquids unloading until later in the well's productive lifetime, the timeframe for initiating liquids unloading operations varies significantly and can be early in the well's productive life span.
- Most of the emissions from liquids unloading operations are produced by less than 10% of the venting well population.

The study does not discuss the characteristics that cause certain wells to have significantly higher emissions than other venting wells. The study showed that the majority of emissions came from a small percentage of venting wells, and both conventional and hydraulically fractured wells can vent during liquids unloading. Additionally, while a large percentage of wells equipped with plunger lifts do not vent during liquids unloading events, many wells with plunger lifts produce emissions during liquids unloading events. This suggests that plunger lifts are capable of unloading liquids from a well without venting, but in many cases they are operated in a manner that results in venting. It is not clear to the EPA what the conditions are that cause these wells with plunger lifts to be operated in a manner that results in significant venting during liquids unloading.

2.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. GHG emissions and removals by source and by economic sector over a time series, beginning with 1990. The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining). The 2014 GHG Inventory data (published in 2014; containing emissions data for 1990-2012) was evaluated for information on liquids unloading emissions.

The 2014 GHG Inventory applied calculated National Energy Modeling System (NEMS) (U.S. EPA, 2014) region- and unloading technology-specific emission factors to the percentage of wells requiring liquids unloading by using the percentages of wells venting for liquids unloading with plunger lifts, and wells without plunger lifts in each region based on API/ANGA Survey data (*see* Section 2.1.1.3 for a discussion on this data).

The 2014 GHG Inventory activity data (number of wells), emissions factors (standard cubic feet per year [scfy]/well) and the calculated emissions for liquids unloading are presented by NEMS region in Table 2-4.

Table 2-4. Data and Calculated CH_4 Emissions [MT] for the Natural Gas Production Sector by NEMS Region (U.S. EPA, 2014, ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories)

NEMS Region	Activity	Activity Data[a,b] (number of wells)	Emission Factor (scfy)/well[b]	Calculated Emissions (MT)
North East	Liquids Unloading (with plunger lifts)	6,924	268,185	35,764
	Liquids Unloading (without plunger lifts; blowdowns)	17,906	141,646	48,849
Midcontinent	Liquids Unloading (with plunger lifts)	2,516	1,140,052	55,245
	Liquids Unloading (without plunger lifts; blowdowns)	4,469	190,179	16,369
Rocky Mountain	Liquids Unloading (with plunger lifts)	10,741	119,523	24,726
	Liquids Unloading (without plunger lifts; blowdowns)	1,267	1,998,082	48,758

NEMS Region	Activity	Activity Data[a,b] (number of wells)	Emission Factor (scfy)/well[b]	Calculated Emissions (MT)
South West	Liquids Unloading (with plunger lifts)	1,379	2,856	76
	Liquids Unloading (without plunger lifts; blowdowns)	8,078	77,899	12,120
West Coast	Liquids Unloading (with plunger lifts)	159	317,292	972
	Liquids Unloading (without plunger lifts; blowdowns)	142	279,351	764
Gulf Coast	Liquids Unloading (with plunger lifts)	1,784	61,758	2,122
	Liquids Unloading (without plunger lifts; blowdowns)	5,445	265,120	27,803
Total		60,810		273,568

[a]DI Desktop, 2014.
[b]API/ANGA 2012 Survey Data, Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production – Summary and Analysis of API and ANGA Survey Responses (API and ANGA, 2012).

The 2014 GHG Inventory data estimates that liquids unloading emissions in 2012 were 14% of overall methane emissions from the natural gas production segment.

2.4 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. and compare those emission estimates to the 2011 estimates reported in the EPA's 2013 GHG Inventory. The sources or operations tested included liquids unloading. Under this study, sampling was performed for liquids unloading in which an operator manually bypassed the well's separator. These manual unloading events could be scheduled, which allowed time to install measurement equipment.

Analysis included nine well unloading events, ranging from 15 minutes to two hours, including both continuous flow and intermittent flow events. Some of the wells sampled only unloaded liquids once over the current life of the well, where others were unloaded monthly. The average emissions per unloading event were 1.1 MT of methane (95% confidence limits of 0.32-2.0 MT). The study reports that the average emissions per well per year (based on the emissions per event for each well multiplied by the frequency of the events per year reported by the well operator) was 5.8 MT. The study acknowledges that the sampled population characteristics reflected a wide range of emission rates and that when emissions are averaged per event, emissions from four of the nine events contribute more than 95% of the total emissions. This result is consistent with the API/ANGA 2012 Survey Data and 2012 data reported to the GHGRP; all suggest that certain wells produce significantly more emissions during liquids unloading events than others. The study also suggests that the length of the liquids unloading event and the number of events are crucial factors in a well's annual emissions from liquids unloading.

The authors report that their study supports their belief that the application of the API/ANGA 2012 Survey data method used when calculating the 2013 GHG Inventory overestimates GHG emissions. Although the authors believe that their study provides valuable information, they caution that the sampling in their study was insufficient to characterize emissions from liquids unloading for all well sites in all basins and recommend that additional measurement of unloading events be conducted in order to improve national emissions estimates. Because characteristics of the unloading events sampled in the study were highly variable, and because the number of events sampled was small, the authors caution the use of the data to extrapolate to larger populations.

2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF International, 2014)

The Environmental Defense Fund (EDF) commissioned ICF International (ICF) to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Liquids unloading is one of the 22 emission sources that is included in the study.

The study relied on the EPA's 2013 GHG Inventory for methane emissions data for the oil and natural gas sector. This emissions data was revised to include updated information from the GHGRP (EPA) and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. The projected emissions are not discussed further here, because projected emissions are not a topic covered by this white paper.

The study used the GHGRP data for 2011 and 2012 to develop new activity and emission factors for wells with liquids unloading. It was assumed that the respondents represented 85% of the industry, therefore, the EPA's 2013 GHG Inventory estimate of the number of venting wells with plunger lifts was increased to 44,286 from 37,643, and the estimate of the number of venting wells without plunger lifts was increased to 31,113 from 26,451.[3] The emission factors were updated by dividing the total emissions for each venting well type (those equipped with plunger lifts and those that were not equipped with a plunger lift) by the total number of reporting wells. The calculated emission factors were 277,000 scf/venting well for wells with plunger lifts and 163,000 scf/venting well for wells without plunger lifts. Using these updated emission factors, ICF estimated a net increase of methane emissions from liquids unloading (as compared to the EPA's 2013 GHG Inventory) by approximately 30% to 17 billion cubic feet (Bcf)(approximately 321,012 MT). This represented the study's baseline methane emissions for 2011 for liquids unloading.

[3] The EPA is unaware of how the study authors determined the GHGRP data represented 85% of the industry.

Further information included in this study on the use of a plunger lift as a mitigation or emission reduction option, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the use of a plunger lift are presented in Section 3.1 of this document.

3.0 AVAILABLE LIQUIDS UNLOADING EMISSIONS MITIGATION TECHNIQUES

As noted previously, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and hydrocarbon liquids) to the surface along with the produced gas. As the bottom well pressure approaches reservoir shut-in pressure, gas flow slows and liquids accumulate at the bottom of the tubing. A common approach to temporarily restoring flow is to vent the well to the atmosphere (well "blowdown") which removes liquids but also produces emissions.

Several techniques are available that could produce less (compared to blowdown) or no emissions from liquids unloading. The following section describes techniques that remove liquids from the well by other means than a blowdown and in the process can reduce the amount of vented gas and, thus, reduce the VOC and methane emissions. These technologies can reduce the need for liquids unloading operations or result in the capture of gas from liquids unloading operations.

3.1 Liquid Removal Technologies

Numerous liquid removal technologies have been evaluated for their emission levels and their potential for eliminating or minimizing emissions from liquids unloading. The Natural Gas STAR program reports the potential for significant emissions reductions and economic benefits from implementing one or more lift options to remove this liquid instead of blowing down the well to the atmosphere (U.S. EPA, 2006b and 2011).

As noted in Section 1 of this document, the Natural Gas STAR program reports that when liquids loading occurs during the productive life of the well, one or more of the following actions are generally taken (U.S. EPA, 2011):

- Shutting in the well to allow the bottom hole pressure to increase, and then venting the well to the atmosphere (well blowdown),
- Swabbing the well to remove accumulated fluids,

- Installing velocity tubing,
- Installing a plunger lift system, and
- Installing an artificial lift system.

In the sections below, the technologies have been divided into "primary" and "remedial" technologies. It is the EPA's understanding that the "primary" technologies are used as more permanent solutions to liquids loading problems, while the "remedial" technologies may mitigate the problem but do not provide a long term permanent solution. These technologies are summarized in Table 3-1.

Table 3-1. Liquid Removal Techniques for Liquid Unloading of Natural Gas Wells

Mitigation Techniques	Description	Applicability	Costs	Efficacy and Prevalence
Primary Techniques				
Plunger Lift Systems	Plunger lifts use the well's own energy (gas/pressure) to drive a piston or plunger that travels the length of the tubing in order to push accumulated liquids in the tubing to the surface (U.S. EPA, 2006b).	Plunger systems have been known to reduce emissions from venting and increase well production. Specific criteria regarding well pressure and liquid to gas ratio can affect applicability. Candidate wells for plunger lift systems generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system (U.S. EPA, 2006b).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2006b and 2011): • Capital, installation and startup cost estimates: $1,900-$7,800 (Note: Commenters on the ICF study cited a cost of $15,000. The study escalated the cost to $20,000 (ICF International, 2014)) • Smart automation system: $4,700/well - $18,000/well depending on the complexity of the system. • Additional startup costs (*e.g.*, well depth survey, miscellaneous well clean out operations): $700-$2,600.	API/ANGA Survey data show plunger lifts can result in zero emissions or significant emissions depending on how they are operated. The EPA has learned plunger lift systems rely on manual, onsite adjustments. When a lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. Optimized plunger lift systems (e.g., with smart well automation) can decrease the amount of gas vented by up to 90+% and reduce the need for venting due to overloading (U.S. EPA, 2006b).

Mitigation Techniques	Description	Applicability	Costs	Efficacy and Prevalence
			• Annual operating and maintenance costs (e.g., inspection and replacement of lubricator and plunger): $700-$1,300 • Annual cost savings from avoided emissions from use of an automated system: $2,400-$10,241.	
Artificial lifts (e.g., rod pumps, beam lift pumps, pumpjacks and downhole separator pumps)	Artificial lifts require an external power source to operate a pump that removes the liquid buildup from the well tubing (U.S. EPA, 2011).	The devices are typically used during the eventual decline in the gas reservoir shut-in pressure, when there is inadequate pressure to use a plunger lift. At this point, the only means of liquids unloading to keep gas flowing is downhole pump technology (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): • Capital and installation costs (includes location preparation, well clean out, artificial lift equipment and pumping unit): $41,000-$62,000/well • Average cost of pumping unit: $17,000-$27,000.	Artificial lifts can be operated in a manner that produces no emissions (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.

Remedial Techniques				
Velocity tubing	Velocity tubing is smaller diameter production tubing and reduces the cross-sectional area of flow, increasing the flow velocity and achieving liquid removal without blowing emissions to the atmosphere. Generally, a gas flow velocity of 1,000 feet per minute (fpm) is necessary to remove wellbore liquids (U.S. EPA, 2011).	• Velocity tubing strings are appropriate for low volume natural gas wells upon initial completion or near the end of their productive lives with relatively small liquid production and higher reservoir pressure. Candidate wells include marginal gas wells producing less than 60 Mcfd (U.S. EPA, 2011). • Coil tubing can also be used in wells with lower velocity gas production (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): • Installation requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well. • Capital and installation costs provided from industry include the following: \$7,000-\$64,000/well	Considered to be a "no emissions" solution. Low maintenance, effective for low volumes lifted. Often deployed in combination with foaming agents. Seamed coiled tubing may provide better lift due to elimination of turbulence in the flow stream (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.
Foaming agents	A foaming agent (soap, surfactants) is injected in the casing/tubing annulus by a chemical pump on a timer basis. The gas bubbling through the soap-water solution creates gas-water foam which is more easily lifted to the surface for water removal (U.S. EPA, 2011).	A means of power will be required to run the surface injection pump. The soap supply will also need to be monitored. If the well is still unable to unload fluid, additional, smaller tubing may be needed to help lift the fluids. Foaming agents work best if the fluid in the well is at least 50% water. Surfactants are not effective for natural gas liquids or liquid hydrocarbons. Foaming agents and velocity tubing may be more effective when used in combination (U.S. EPA, 2011).	The following information is from the EPA's Natural Gas STAR Program technical documents, however, additional cost data may be available such as from equipment or service providers (U.S. EPA, 2011): Foaming agents are low cost. No equipment is required in shallow wells. In deep wells, a surfactant	Considered to be a "no emissions" solution. Low volume method applied early in production decline when bottom hole pressure still generates sufficient velocity to lift liquid droplets (U.S. EPA, 2011). The EPA does not have information on the prevalence of this technology in the field.

			injection system requires the installation of surface equipment and regular monitoring. Pump can be powered by solar or AC power or actuated by movement of another piece of equipment. • Capital and startup costs to install soap launchers: $500-$3,880 • Capital and startup costs to install soap launchers and velocity tubing: $7,500-$67,880 • Monthly cost of foaming agent: $500/well or $6,000/yr	

3.1.1 Primary Techniques

Plunger Lifts

Based on our assessment of the data, a plunger lift system for liquids unloading is capable of performing liquids unloading with little or no emissions. The level of emissions depends on how the plunger lift system is operated, specifically, whether gas is directed to the sales line or vented to the atmosphere. There may be potential for improved production and emissions reduction when paired with a smart well automation that optimizes production and reduces product losses to the atmosphere. A schematic diagram of a plunger lift is shown in Figure 3-1.

Basic installation costs for plunger lifts were estimated as ranging from $1,900 - $7,800 based on information gathered from the EPA's Natural Gas STAR program (*see* Table 3-1). Plunger lift installation costs include installing the piping, valves, controller and power supply on the wellhead and setting the downhole plunger bumper assembly, assuming the well tubing is open and clear. Lower costs (*e.g.*, $1,900) would result where no other activities are required for installation. Higher costs (*e.g.*, $7,800) would be incurred in situations where running a wire-line, which is necessary to check for internal blockages within the tubing, and a test run of the plunger is conducted from top to bottom (a process also known as broaching) to ensure that the plunger will move freely up and down the tubing string (U.S. EPA, 2006b).

Other startup costs in addition to the installation costs can include a well depth survey, swabbing to remove well bore fluids, removing mineral scale and cleaning out perforations, fishing out debris in the well, and other miscellaneous well clean out operations. Additional startup costs were estimated to be $700 - $2,600 (U.S. EPA, 2006b). However, commenters on the ICF study cited startup costs of $15,000. The commenters also stated that well treatments and clean outs are often required before plunger lifts can be installed. The study escalated the cost to $20,000 per well (ICF International, 2014).

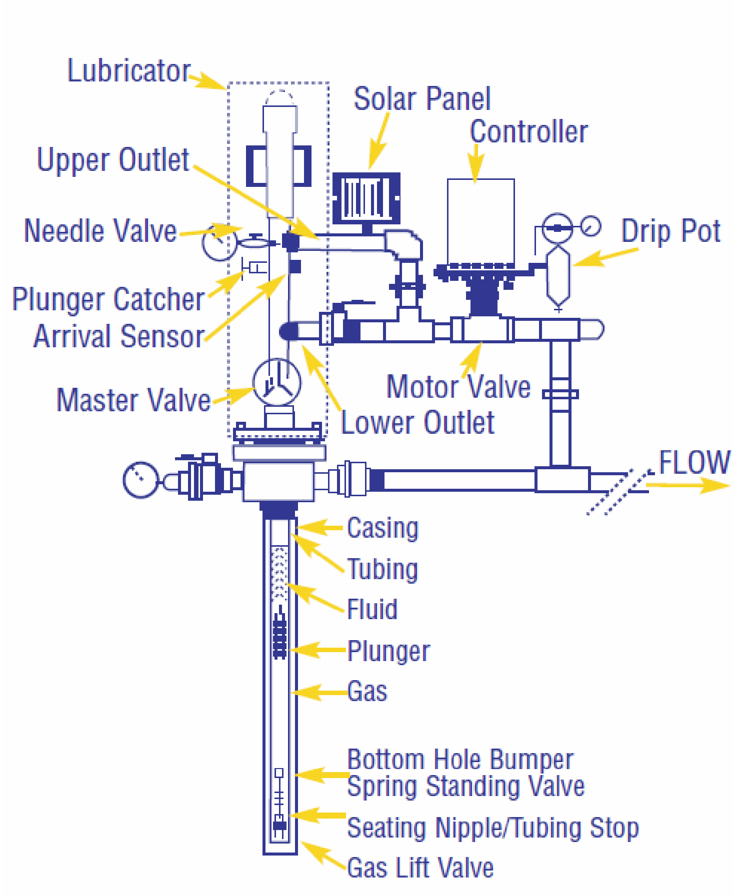

Figure 3-1. Example Plunger Lift (U.S. EPA, 2006b)

The activities to install the smart automation plunger lift include installing the controller, power supply, and host system, in addition to the activities required for the plunger itself. The typical cost of automating a plunger lift system is approximately $5,700 - $18,000, depending on the complexity of the well. This cost would be in addition to the startup costs of a plunger-only system (U.S. EPA, 2011). Installing telemetry units can help to optimize production; however, automated controllers are not necessarily required for reducing emissions.

Natural Gas STAR Partners have reported methane emissions reductions and economic benefits from implementing plunger lifts as compared to conducting blowdowns, especially those equipped with smart automation systems. The reported economic benefits from natural gas savings and improved well production range from $2,400 - $4,389 per well per year[4] (U.S. EPA, 2011). The EPA is not aware of any adverse secondary environmental impacts that would result from the installation and operation of plunger lifts in a liquid producing natural gas well, and the use of a smart automated plunger lift system has the potential to optimize production and minimize emissions over the use of a non-automated plunger lift system.

The ICF study (ICF International, 2014) calculated emission control cost curves ($/Mcf of methane reduced) using their 2018 projected methane emission estimates. The primary sources used for projecting onshore methane emissions for liquids unloading for 2018 included natural gas forecast information from the U.S. EIA's Annual Energy Outlook (AEO) and 2014 Early Release (*Lower 48 Natural Gas Production and Supply Prices by Supply Region*) and API's Quarterly Well Completions Report. The EIA information was used to project methane emissions by using regional gas production information projected in EIA's 2014 AEO for 2018. The API's report was used to update well counts by EIA AEO regions whereby a ratio of the number of wells in 2018 to wells in 2011 was used to drive the activity for most of the emission sources involved in gas production. The study assumed the application of a plunger lift (assuming 95% control of methane emissions) on 30% of the estimated venting wells without plunger lifts. ICF estimated a methane reduction of 1.6 Bcf (or approximately 30,212 MT) at a cost of $0.74/Mcf methane reduced with the application of a plunger lift on these uncontrolled wells. ICF also estimated that VOC emissions would be reduced by 9.3 kilotons (or approximately 9,300 MT) at a cost of $125/ton. According to the report, liquids unloading can increase production by anywhere from 3 to 300 thousand cubic feet per day (Mcf/day) and, without taking credit for the productivity increase, the report estimates that the cost-effectiveness breakeven point is about 1,200 Mcf/yr of venting (estimated as a reduction cost of $0.05/Mcf reduced). Their analysis assumed capital costs of $20,000 and annual operating costs of $2,400.

Artificial Lift Systems

Artificial lift systems (e.g., rod pumps and pumping units) require an external power source to operate, such as electric motors or natural gas fueled engines. However, these systems can be

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[4] Assumes a gas price of $3 per Mcf.

installed and effectively remove liquids from the well even after the well pressure has declined to the point where a plunger lift system can no longer be operated, thus they are capable of prolonging the life of a well. They typically require the use of a well workover rig to install a downhole rod pump, rods, and tubing in the well.

Based on results reported by Natural Gas STAR Partners, the cost of implementing artificial lift systems range from $41,000 - $62,000. The reported economic benefits from natural gas savings range from $2,919 - $6,120 per well per year[5] (U.S. EPA, 2011).

Secondary environmental impacts occur due to the emissions from the natural-gas fueled engine used to power the lift system, however, these impacts can be reduced by using an electric motor instead.

3.1.2 Remedial Techniques

Velocity Tubing

As was described previously, liquids build up in the well tubing as well pressure declines and the gas flow velocity is not sufficient to push the liquids out of the well tubing. Velocity tubing (smaller diameter production tubing) decreases the cross-sectional area of the conduit through which the gas flows and thus increases the velocity of the flow. The Natural Gas STAR Program uses 1,000 fpm as a general rule of thumb for the velocity necessary to remove liquids from the well (Note: This is a rule of thumb and the actual required velocity will differ based on well characteristics). When velocity tubing is installed, it must be a small enough diameter to increase the gas flow velocity to 1,000 fpm or to the necessary velocity to remove the liquids from the particular well. A well workover rig is required to remove the existing production tubing and replace it with the velocity tubing. The EPA experience through the Natural Gas STAR Program suggests the wells that are the best candidates for this technology are marginal wells that produce less than 60 Mcfd. However, as well pressure continues to decline as the well ages, the installed velocity tubing may no longer be sufficient to increase the gas flow velocity to the level necessary to remove liquids from the well. At this point, velocity tubing of a smaller diameter or other liquids

[5] Estimate does not include value of improved well production. Assumes a gas price of $3 per Mcf.

removal technologies may be required to remove liquids from the well tubing.

Based on results reported by Natural Gas STAR Partners, the cost of implementing velocity tubing ranges from $7,000 - $64,000. The reported economic benefits from natural gas savings and improved well production range from $27,855 - $82,830 per well per year[6] (U.S. EPA, 2011). The EPA is not aware of any adverse secondary environmental impacts that would result from the installation and operation of velocity tubing.

Foaming Agents

Foaming agents can help to remove liquids from wells that are accumulating liquids at low rates. The foam produced from surfactants can reduce the density of the liquid in the well tubing and can also reduce the surface tension of the fluid column, which reduces the gas flow velocity necessary for pushing the liquid out of the well tubing. This technology can be used in conjunction with velocity tubing. However, foaming agents work best when the majority of the liquid built up in the well tubing is water, because they are not effective on natural gas liquids or liquid hydrocarbons (U.S. EPA, 2011).

The foaming agent can be delivered into the well as a soap stick or it can be injected into the casing-tubing annulus or a capillary tubing string. If the well is deep, then an injection system is required that includes foaming agent reservoir, an injection pump, a motor valve with a timer and a power source for the pump (e.g., AC power for electric power or gas for pneumatic pumps) (U.S. EPA, 2011).

Based on results reported by Natural Gas STAR Partners, the costs of foaming agents range from $500 - $9,880. The reported economic benefits from natural gas savings and improved well production range from $1,500 - $28,080 per well per year[7] (U.S. EPA, 2011).

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[6] Assumes a gas price of $3 per Mcf.
[7] Assumes a gas price of $3 per Mcf.

For deep wells that require an injection system, secondary environmental impacts occur due to the emissions from the power source for the pump. Pneumatic pumps can result in vented gas emissions and electric pumps emissions depending on the source of the electric power.

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of VOC and methane emissions from liquids unloading and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding this source of VOC and methane emissions:

- A majority of gas wells (conventional and unconventional) must perform liquids unloading at some point during the well's lifetime. As gas wells age and well pressure declines, the need for liquids unloading to enhance well performance becomes more likely.
- The 2014 GHG Inventory estimates the 2012 liquids unloading emissions to be 14% of natural gas production sector emissions.
- The majority of emissions from liquids unloading events come from a small percentage of wells. Some of the characteristics that affect the magnitude of liquids unloading annual emissions from a well are the length of time of each event and the frequency of events.
- A wide range of emission rates from blowdowns have been reported from the limited available well-level data. In the Allen et. al. study, when emissions are averaged per event, emissions from four of the nine events included in the study contribute more than 95% of the total emissions. This result is consistent with the API/ANGA 2012 Survey data and 2012 data reported to the GHGRP; all suggest that certain wells produce more emissions during blowdowns than others. Some suggested causes of this variation are the length of the blowdown and the number of blowdowns per year, which are affected by underlying geologic factors.
- Industry has developed several technologies that effectively remove liquids from wells and can result in fewer emissions than blowdowns. Plunger lifts are the most common of those technologies.

- The emissions reduction efficiency plunger lifts can achieve varies greatly depending on how the system is operated. It is not clear to the EPA what the conditions are that lead to wells with plunger lifts to be vented during plunger lift operation.
- The two liquids unloading techniques that result in vented emissions that the EPA is aware of are plunger lifts when vented to the atmosphere and blowdowns.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Please comment on the national estimates of methane emissions and methane emission factors for liquids unloading presented in this paper. Please comment on regional variability and the factors that influence regional differences in VOC and methane emissions from liquids unloading. What factors influence frequency and duration of liquids unloading (e.g., regional geology)?
2. Is there further information available on VOC or methane emissions from the various liquids unloading practices and technologies described in this paper?
3. Please comment on the types of wells that have the highest tendency to develop liquids loading. It is the EPA's understanding that liquids loading becomes more likely as wells age and well pressure declines. Is this only a problem for wells further down their decline curve or can wells develop liquids loading problems relatively quickly under certain situations? Are certain wells (or wells in certain basins) more prone to developing liquids loading problems, such as hydraulically fractured wells versus conventional wells or horizontal wells versus vertical wells?
4. Did this paper capture the full range of feasible liquids unloading technologies and their associated emissions? Please comment on the costs of these technologies. Please comment on the emission reductions achieved by these technologies. How does the well's life cycle affect the applicability of these technologies?
5. Please provide any data or information you are aware of regarding the prevalence of these technologies in the field.
6. In general, please comment on the ability of plunger lift systems to perform liquids unloading

without any air emissions. Are there situations where plunger lifts have to vent to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where it is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

7. Based on anecdotal experience provided by industry and vendors, the blowdown of a well removes about 15% of the liquid, while a plunger lift removes up to 100% (BP, 2006). Please discuss the efficacy of plunger lifts at removing liquids from wells and the conditions that may limit the efficacy.

8. Please comment on the pros and cons of installing a plunger lift system during initial well construction versus later in the well's life. Are there cost savings associated with installing the plunger lift system during initial well construction?

9. Please comment on the pros and cons of installing a "smart" automation system as part of a plunger lift system. Do these technologies, in combination with customized control software, improve performance and reduce emissions?

10. Please comment on the feasibility of the use of artificial lift systems during liquids unloading operations. Please be specific to the types of wells where artificial lift systems are feasible, as well as what situations or well characteristics discourage the use of artificial lift systems. Are there standard criteria that apply?

11. The EPA is aware that in areas where the produced gas has a high H_2S concentration combustion devices/flares are used during liquids unloading operations to control vented emissions as a safety precaution. However, the EPA is not aware of any instances where combustion devices/flares are used during liquids unloading operations to reduce VOC or methane emissions. Please comment on the feasibility of the use of combustion devices/flares during liquids unloading operations. Please be specific to the types of wells where combustion devices/flares are feasible. Are there operational or technical situations where combustion devices/flares could not be used?

12. Given that liquids unloading may only be required intermittently at many wells, is the use of a mobile combustion device/flare feasible and potentially less costly than a permanent combustion device/flare?

13. Given that there are multiple technologies, including plunger lifts, downhole pumps and velocity tubing that are more effective at removing liquids from the well tubing than blowdowns, why do owners and operators of wells choose to perform blowdowns instead of employing one of these technologies? Are there technical reasons other than cost that preclude the use of these technologies at certain wells?

14. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from liquids unloading events and available options for increased product recovery and emissions reductions? The EPA is aware of an additional stage of the Allen et al. study to be completed in partnership with the EDF and other partners that will directly meter the emissions from liquids unloading events. However, the EPA is not aware of any other ongoing or planned studies addressing this source of emissions.

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Chapter 9

Economic Impact Analysis

The detailed study of regulatory consequences allows policy makers to fully understand a regulation's impacts, and to make an informed decision on its appropriateness. Economic information is necessary for the evaluation of at least two types of consequences of a regulatory policy: the regulation's efficiency, and its distributional effects. In principle, both could be estimated simultaneously using a general equilibrium model. In practice however, they are usually estimated separately.

The distributional effects of environmental regulations can be examined through an economic impact analysis (EIA). A related analysis, called an equity assessment, addresses the distribution of impacts across individuals and households, with particular attention to economically or historically disadvantaged or vulnerable groups (e.g., low-income households, racial or ethnic minorities, and young children). Equity assessments are sometimes referred to as environmental justice (EJ) analyses and are the subject of Chapter 10.

An EIA identifies the specific entities that benefit from or are harmed by a policy, and then estimates the magnitude of their gains and losses including changes in profitability, employment, prices, government revenues or expenditures, and trade balances. These estimates are derived from a study of the economic changes that occur across broadly-defined economic sectors of society, including industry, government, and not-for-profit organizations, but may also include more narrowly defined sectors within these broad categories, such as the solid waste industry or even an individual solid waste company. EIAs can measure a broad variety of impacts, such as direct impacts on individual plants, whole firms, and industrial sectors, as well as indirect impacts on consumers and suppliers.

9.1 Statutes and Policies

The following major statutes and EOs, all described in Chapter 2, directly address impact analyses:[1]

- Regulatory Flexibility Act of 1980 (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA);
- Unfunded Mandates Reform Act of 1995 (UMRA);
- EO 13132, "Federalism";
- EO 13175, "Consultation and Coordination with Indian Tribal Governments;" and
- EO 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use."

Together with OMB's *Circular A-4*, they raise important dimensions relevant for economic impact analyses as summarized in Table 9.1.

1 EPA's Regulatory Management Division's Action Development Process (ADP) Library (http://intranet.epa.gov/adplibrary) is a resource for those who wish to access relevant statutes, EOs, or Agency policy and guidance documents in their entirety.

NMED Rebuttal Exhibit 10

Table 9.1 - Potentially Relevant Dimensions to Economic Impact Analyses[2]

Dimension	Statute, Order, or Directive	Entity	Subpopulation
Sector	UMRA; EO 13132; OMB *Circular A-4*	Industry or government	Industries or state, local, or tribal governments
Entity size	RFA; UMRA; OMB *Circular A-4*	Businesses, governments, or not-for-profit organizations	Small businesses, small governmental jurisdictions, or small not-for-profit organizations
Time	OMB *Circular A-4*	Individuals or households	Current or future generations
Geography	OMB *Circular A-4*; UMRA	Region	Regions, states, counties, or non-attainment areas
Energy	EO 13211	Entities that use, distribute, or generate energy	Energy sector

The term "affected" is used throughout this chapter as a general term. Analysts should be aware that the authorizing statute for the rule, as well as other applicable statutes and administrative orders noted in this chapter, may make more specific use of this term. For example, the Regulatory Flexibility Act includes the clause "subject to the requirements of the rule" when quantifying economic impacts, meaning that the analysis considers only those entities that are directly regulated by the rule. On the other hand, provisions in the UMRA and EO 12866 address both direct and indirect impacts, and therefore define the affected population more broadly. Care should be taken to avoid double counting when estimating direct and indirect impacts.

9.2 Conducting an Economic Impact Analysis

There are three important distinctions between BCA and EIA to keep in mind when conducting an EIA.[3] First, total social benefits and total social costs are not of primary importance in an EIA, as they are in a BCA. Rather, the main focus is on the components and distribution of the total social benefits and costs.

Second, transfers of economic welfare from one group to another are no longer assumed to cancel each other out, as they do in a BCA. Taxpayers, consumers, producers, governments, and the many sub-categories of these groups are all considered separately. While a BCA relies on estimates of the social benefits and costs of a regulation, an EIA focuses on the private benefits and costs associated with compliance responses. The EIA should use the same "starting point" as the BCA (i.e., same engineering or direct compliance costs, same benefit categories, etc.) for developing private benefit and cost estimates. In addition, some adjustments to these costs may be needed, as discussed below. For example, the tax status of a required piece of equipment is considered in private costs, but not in social costs.

Finally, there is a greater need for disaggregation in EIAs than in BCAs. Results may be presented for specific counties or other geographic units or types of entities, as appropriate, placing heavy demands on the modeling framework.

For any regulation, it is essential to ensure consistency between the EIA and the benefit-cost analysis (BCA). If a BCA is conducted, the corresponding EIA must be conducted within the same set of analytical assumptions. To the extent possible, adjustments to these assumptions or to the overall modeling framework used for the BCA should only be made when absolutely necessary, and then should be noted clearly in the text of the analysis.

2 Some environmental statutes may also identify subpopulations that merit additional consideration. This document is limited to those statutes with broad coverage.

3 Traditionally, EIAs focus on the costs of a particular rule or regulation. However, it is also possible to focus on the distribution of benefits or to calculate the net benefits for particular entities.

NMED Rebuttal Exhibit 10

9.2.1 Screening for Potentially Significant Impacts

A comprehensive analysis of all aspects of all economic impacts associated with a rule can require significant time and resources, and its accuracy and thoroughness depend on the quality and quantity of available data. Thus, screening analyses are often employed to determine data availability, the severity of a rule's anticipated impacts, and the potential consequences of further analysis if undertaking it would require a delay in the regulatory schedule. A screening analysis can be thought of as a "mini-EIA" consisting of a rough examination of the data to identify sectors that may warrant further analysis.[4] Screening is effective for identifying the magnitude of the overall level of impacts on the regulated industry, but may fail to identify potentially large impacts on a single sector, region, or facility.

There are no established definitions for what constitutes a large or a small impact. However, a screening analysis is a tiered approach that initially captures most of the possible impacts (i.e., allows for many false positives) followed by a more detailed analysis that can help eliminate unfounded impacts. In this way, the screening analysis will eventually balance the risk of identifying "false positives" and "false negatives."

9.2.2 Profile of Affected Entities

Analysts should consider changes imposed by the rule in the regulated industry, as well as how related industries may be affected. Some industries may benefit from the regulation, while others may be subject to significant costs. If the regulation causes a firm to use different inputs or new technologies, then the producers of the new inputs will gain, while the producers of the old inputs will suffer. Developing a detailed industry profile will identify those industries that may be affected positively and negatively by the regulation.

4 The screening analysis discussed in this section is distinct from the screening analysis required to comply with the Regulatory Flexibility Act (as referred to in Section 9.3).

9.2.2.1 Compiling an Industry Profile and Projected Baseline

To determine the impacts of a particular regulation the analyst must understand the underlying structure of the affected industry and its various linkages throughout the economy.[5] This includes an understanding of the condition of the industry in terms of its finances and structure in the absence of the rule —the baseline of the EIA. A rule may impose different requirements and costs on new versus existing entities. Such rules may affect industry competition, growth, and innovation by raising barriers to new entry or encouraging continued use of outdated technology. Thus, a substantial portion of an EIA involves characterizing the state of the affected firms and industries in the absence of the rule as a basis for evaluating economic impacts.

The following are important inputs to defining an industry profile:

- **North American Industrial Classification System (NAICS) industry codes.** NAICS has replaced the U.S. Standard Industrial Classification (SIC) system in the U.S. Department of Commerce (DOC) Economic Census and other official U.S. Government statistics. NAICS was developed to provide comparable statistics about business activity across North America. It identifies hundreds of new, emerging, and advanced technology industries and reorganizes existing industries into more meaningful sectors, particularly in the service sector.[6]
- **Industry summary statistics.** Summary statistics of total employment, revenue, number of establishments, number of firms, and size of firms are available from U.S. DOC Economic Census or the Small Business Administration.[7]

5 Generally, analysts should initially assume a perfectly competitive market structure. One of the primary purposes of developing an industry profile is to confirm this assumption or discover evidence to the contrary.

6 For more information see www.census.gov/epcd/www/naics.html, which includes a NAICS/SIC correspondence (accessed on January 21, 2011).

7 See www.sba.gov/advocacy/849 for more information (accessed on January 21, 2011).

- **Baseline industry structure.** Industry-level impacts depend on the competitive structure and organization of the industry and the industry's relationship to other economic entities. The number and size distribution of firms/facilities and the degree of vertical integration within the industry are important aspects of industry structure that affect the economic impact of regulations.
- **Baseline industry growth and financial condition.** Industries and firms that are relatively profitable in the baseline will be better able to absorb new compliance costs or take advantage of potential benefits without experiencing financial distress. Industries that are enjoying strong growth may be better able to recover increased costs through price increases than they would if there were no demand growth. Section 9.3.3.3 provides suggestions for using financial ratios to assess the significance of economic impacts on a firm's financial condition.
- **Characteristics of supply and demand.** Assessing the likelihood of changes in production and prices requires information on the characteristics of supply and demand in the affected industries. The relevant characteristics are reflected in price elasticities of supply and demand, which, if available, allow direct quantitative analysis of changes in prices and production. Often, reliable estimates of elasticities are not available and the analysis of industry-level adjustments must rely on simplifying assumptions and qualitative assessments. See Appendix A for a discussion of elasticities.

9.2.2.2 Profile of Government Entities and Not-for-Profit Organizations

Analysts should carefully consider whether a particular rule will directly affect government entities, not-for-profit organizations, or households.[8] For example, air pollution regulations that apply to power plants may affect government entities such as municipally-owned electric companies. Air regulations that apply to vehicles may affect municipal buses, police cars, and public works vehicles. Effluent guidelines for machinery repair activities may affect municipal garages. The profile of these affected entities should include a brief description of relevant factors or characteristics.

Relevant factors for *government entities* may include:

- Number of people living in the community;
- Property values;
- Household income levels (e.g, median, income range);
- Number of children;
- Number of elderly residents;
- Unemployment rate;
- Revenue amounts by source; and
- Credit or bond rating of the community.

If property taxes are the major revenue source, then the assessed value of property in the community and the percentage of this assessed value represented by residential versus commercial and industrial property should be determined. If a government entity serves multiple communities, such as a regional water or sewer authority, then relevant information should be collected for all the communities covered by the government entity. Socioeconomic factors influence demands on state or local government resources; for example a high proportion of children means more educational resources.

Data on community size, income, number of children and elderly, and unemployment levels are available from the U.S. Census Bureau. Data on property values, amount of revenue collected from each revenue source, and credit rating may be available from the community or state finance agencies. Most county websites provide information on property values. Private companies, such as Standard and Poor's (S&P), or Fitch's, provide community credit ratings.

8 Government entities that may be affected include states, cities, counties, townships, water authorities, villages, Indian Tribes, special districts, and military bases. Not-for-profit entities that may be affected include not-for-profit hospitals, colleges, universities, and research institutions.

Depending on the number of communities affected and the level of detail warranted, the analysis may rely on generally available aggregate data only. In other cases, a survey of affected communities may be necessary.[9]

Relevant characteristics of *not-for-profit entities* include:

- Entity size and size of community served;
- Goods or services provided;
- Operating costs; and
- Amount and sources of revenue.

If the entity is raising its revenues through user fees or charging a price for its goods or services (such as university tuition), then the income levels of its clientele are relevant. If the entity relies on contributions, then it would be helpful to know the financial and demographic characteristics of its contributors and beneficiaries. If it relies on government funding (such as Medicaid) then possible future changes in these programs should be identified.

9.2.2.3 Profile of Small Entities

Small entities include small businesses, small governments and small not-for-profit institutions. While these entities may require special considerations, as detailed below, the profiling of them should follow the same steps as discussed above.

9.2.2.4 Data Sources for Profiles

Profiles generally rely on information from the following sources: websites for affected communities, industry trade publications, and the U.S. Census Bureau.[10] Relevant literature can be useful in characterizing industry activities and markets as well as regulations that already affect the industry. Relevant literature can usually be efficiently identified through a computerized search using on-line services such as Dialog, BRS/Search Services, Dow Jones News/Retrieval, or EconLit. These on-line services contain more than 800 databases covering business, economic, and scientific topic areas. Table 9.2 describes some commonly used data sources for retrieving quantitative data.[11]

The industry profile may also identify situations where insufficient data are available from standard sources. This situation could potentially arise when the affected industry has many product lines or activities affected by the rule. In addition, for some rules it may be difficult to identify the appropriate NAICS industry for all the firms or facilities affected by the rule if the industry can be categorized in multiple ways. In these cases, and particularly if facility-level data are required to estimate economic impacts, a survey of affected facilities may be required to provide sufficient data for analysis.

9.2.3 Detailing Impacts on Industry

This section explains how to determine the impact on individual plants or businesses so as to identify whether a particular plant or industry is likely to bear a disproportionate portion of the costs or benefits of a regulation.

9.2.3.1 Impacts on Prices

Predicted impacts on prices form the basis for determining how compliance costs are distributed between the directly-affected firms, their customers, and other related parties in a typical market. At one extreme, regulated firms may not be able to raise prices at all, and would consequently bear the entire burden of the added costs in the form of reduced profits. Reduced profits may result from reduced earnings on continuing production, lost profits on products or services that are no longer produced, or some combination of the two.

9 In cases where a survey is needed, care should be taken to comply with the requirements of the Paperwork Reduction Act (PRA) (44 U.S.C. 3501).

10 Academic literature may or may not contain quantitative data.

11 The Thomas Registry (www.thomasnet.com) is a source of qualitative information on manufacturing companies in the United States (accessed on January 21, 2011). In addition, Lavin (1992) provides sources of business information.

Table 9.2 - Commonly Used Profile Sources for Quantitative Data

Source	Data
Trade Publications and Associations	Market and technological trends, sales, location, regulatory events, ownership changes
U.S. Department of Commerce, Economic Census (www.census.gov)	Sales, receipts, value of shipments, payroll, number of employees, number of establishments, value added, cost of materials, capital expenditures by sector, household and community characteristics
U.S. Department of Commerce, *U.S. Industry & Trade Outlook* (http://www.ita.doc.gov/td/industry/OTEA/outlook/ or http://outlook.gov/)	Description of industry, trends, international competitiveness, regulatory events
U.S. Department of Commerce, *Pollution Abatement Costs and Expenditures Survey* (www.census.gov/mcd)	Pollution abatement costs for manufacturing facilities by industry, state, and region
U.S. Department of Commerce, *Census of Governments* (www.census.gov/govs/index.html)	Revenue, expenditures debt, employment, payroll, assets for counties, cities, townships, school districts
United Nations, International Trade Statistics Yearbook	Foreign trade volumes for selected commodities, major trading partners
Risk Management Association, *Annual Statement Studies* (www.rmahg.org/ann_studies/asstudies.html)	Income statement and balance sheet summaries, profitability, debt burden and other financial ratios, all expressed in quartiles and available for recent years (based on loan applicants only)
Dun & Bradstreet Information Services (www.dnb.com/us/)	Type of establishment, NAICS code, address, facility and parent firm revenues and employment
Standard & Poors (www.standardandpoors.com)	Publicly-held firms, prices, dividends, and earnings, line-of-business and geographic segment information, S&P ratings, quarterly history (10 years), income statement, ratio, cash flow and balance sheet analyses and trends
Securities and Exchange Commission Filings and Forms (EDGAR System Database) (www.sec.gov/edgar.shtml)	Income statement and balance sheet, working capital, cost of capital, employment, outlook, regulatory history, foreign competition, lines of business, ownership and subsidiaries, mergers and acquisitions
Value Line *Industry Reports*	Industry overviews, company descriptions and outlook, performance measures

Suppliers to the directly-affected firms might bear part of the burden in lost earnings if the regulation results in a decline in demand for particular products.[12] At the other extreme, firms may be able to raise prices enough to recover costs fully. In this case, there is no impact on the profitability of the directly-affected firms but their customers bear the burden of increased prices. Assuming perfect competition, the amount of price pass-through depends on the relative elasticity of supply and demand. Another economic impact to consider is the potential backward shifting of regulatory costs (e.g., lowering wages of workers).

In general, the likelihood that price increases will occur can be evaluated by considering whether competitive conditions allow the affected facilities to pass their costs on to consumers.

12 For example, regulations limiting SO_2 emissions may result in reduced demand for high-sulfur coal, which results in a fall in the price of such coal and lost profits for its producers. While there is no clear rule for how far down the chain of effects one needs to consider, it is important to address effects that are likely to be substantial.

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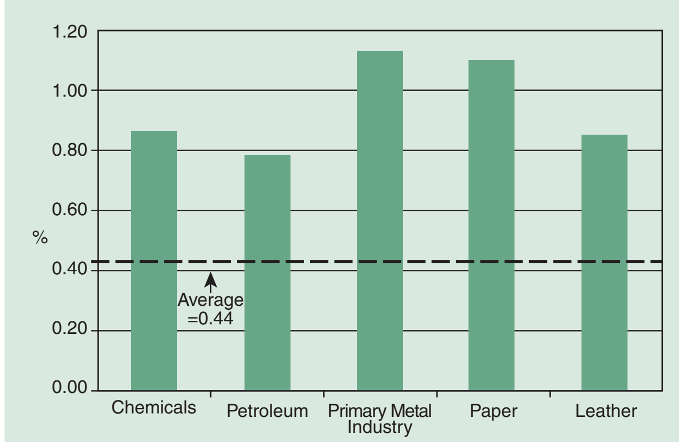
The methods used to conduct the analysis of the directly-affected markets depend on the availability of appropriate estimates of supply and demand elasticities.[13] As noted above, in cases where reliable estimates of elasticities are not available, the analyst must rely on a more basic investigation of the characteristics of supply and demand in the affected market to reach a conclusion about the likelihood of full or partial pass-through of costs via price increases. An examination of the number of firms, quantity of a product produced, and industry size will provide basic information about supply and demand. If an industry is highly concentrated with few producers then firms may be able to easily pass costs on to households and a 100 percent pass-through assumption may be justifiable. Of course, an industry with many producers would mean the opposite assumption.

9.2.3.2 Impacts on Production

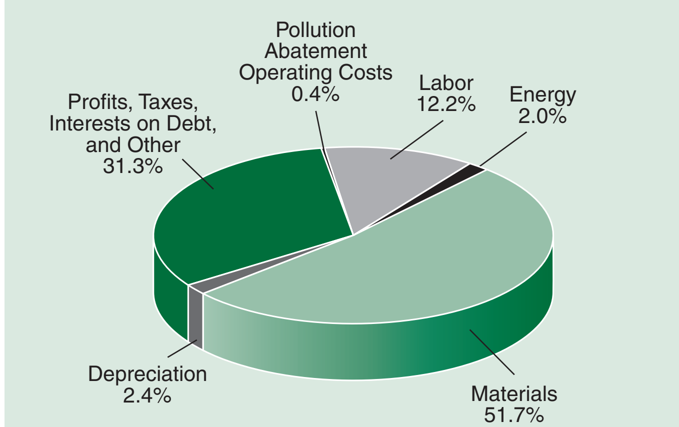
Abatement costs tend to be only a small fraction of total manufacturing revenues. As such, even small changes in wage rates, materials costs, or capital costs are likely to have a much larger effect on manufacturing industries than any changes in environmental regulation. The U.S. Census Bureau collects data on pollution abatement capital expenditures and operating costs incurred to comply with local, state, and federal regulations and on voluntary or market-driven pollution abatement activities.[14] According to the 2005 PACE Survey, the U.S. manufacturing sector spent approximately $20.7 billion dollars on pollution abatement operating costs. This figure represents less than 1 percent of the sector's total revenue, which is similar to the historical average. Moreover, every manufacturing industry, including the most highly regulated ones, spend less than 1.2 percent of their revenues on pollution abatement. Figure 9.1 presents data for the five industries with the highest pollution abatement operating costs (PAOC) as a percent of total revenues.

Figure 9.1 - Pollution Abatement Costs as a Percentage of Total Revenues for Industries with Highest Pollution Abatement Costs in 2005



Source: Pollution Abatement Costs and Expenditures: 2005

Figure 9.2 - Pollution Abatement Costs are a very Small Percentage of Total Manufacturing Costs



Source: U.S. Census Bureau, Pollution Abatement Costs and Expenditures: 2005
U.S. Census Bureau, Annual Survey of Manufacturers: 2005

Considering the historical data, it is unlikely that the typical pollution control regulation will sufficiently increase the cost of doing business so as to make a meaningful part of production unprofitable, or will significantly reduce the quantity of output demanded as producers raise their prices to maintain profitability. Figure 9.2 shows the relative magnitude of each cost category for the manufacturing sector. Based on these relative magnitudes, reducing abatement costs by 10 percent will only reduce the total costs faced by industry by less than 1 tenth of 1 percent. Conversely, lowering material costs by 10 percent will reduce total costs by just over 5 percent as

13 See Appendix A for a more complete discussion of elasticity.

14 More detail on the PACE Survey is available at http://yosemite.epa.gov/ee/epa/eed.nsf/pages/pace2005.html (accessed March 13, 2011).

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material costs were roughly 50 percent of revenues in 2005. Exceptions may be regulations banning the sale or manufacture of a specific product (e.g., a chemical ban) or when a production process is made obsolete. In these situations, the analyst should assess whether the existing plants have other profitable uses.

9.2.3.3 Impacts on employment

The chapters on benefits (Chapter 7) and costs (Chapter 8) point out that regulatory-induced employment impacts are not, in general, relevant for a BCA. For most situations, employment impacts should not be included in the formal BCA.[15] However, if desired the analyst can assess the employment impacts of a regulation as part of an EIA. If this task is undertaken, the analyst needs to quantify all of the employment impacts, positive and negative, to present a complete picture of the effects. This section identifies pitfalls often encountered when performing an EIA and discusses the preferred approaches for conducting one.

Many analyses only present the employment effect on the regulated industry as a result of higher regulatory compliance costs. In doing so, these analyses make simplifying assumptions that employment in a given industry is proportional to output, i.e., if production goes down by 1 percent, employment goes down by 1 percent. These limited assessments on employment impacts from regulation examine how higher manufacturing costs lead to fewer sales and therefore lower employment in that sector. However, empirical and theoretical modeling suggests that these simplified relationships are faulty and should not be used.

In fact, it is not even clear that employment in the regulated industry goes down as a result of environmental regulation. Morgenstern et al. (2002) decompose the labor consequences in an industry facing increased abatement costs. They identify three separate components:

- **Demand effect:** Higher production costs raise market prices. Higher prices reduce consumption (and production) reducing demand for labor within the regulated industry;
- **Cost effect:** As production costs increase, plants use more of all inputs including labor to produce the same level of output. For example, pollution abatement activities require additional labor services to produce the same level of output; and
- **Factor-shift effect:** Post-regulation production technologies may be more or less labor intensive (i.e., more/less labor is required per dollar of output).

Morgenstern et al. empirically estimate this model for four highly polluting/regulated industries to examine the effect of higher abatement costs from regulation on employment. They conclude that increased abatement expenditures generally do not cause a significant change in employment. Specifically, their results show that, on average across the industries they consider, each additional $1 million of spending on pollution abatement results in a (*statistically insignificant*) net increase of 1.5 jobs. However, they find that for two of their four industries (pulp and paper, and steel) additional abatement spending leads to a *statistically significant*, yet quite small, net increase in jobs due to the substitution of labor for other inputs and relatively inelastic estimated demand for their output.[16]

Finally, one effect that Morgenstern et al. do not consider is the effect regulation has on employment in industries that make substitute products, often cleaner products. Demand for these products increases as consumers respond to changes in costs. For example, more expensive virgin paper will cause a shift to more recycled paper. The recycled paper industry will employ more workers as sales increase. Similarly, employment in industries that are complements

15 Appendix C discusses long-term, structural employment changes brought on by land clean up and reuse or other policies that may have a benefit component to them.

16 These results are similar to Berman and Bui (2001) who find that while sharply increased air quality regulation in Los Angeles to reduce NOx emissions resulted in large abatement costs they did not result in substantially reduced employment.

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may decrease. The analyst should also take these effects into consideration when analyzing the effect of regulations on employment.

In addition to the changes in the regulated industry as modeled by Morgenstern et al., the analyst should assess the increased employment in the environmental protection industry. The engineering analysis may provide some data on the labor required to design, build, install (and in some cases operate) the pollution control equipment. For example, a recent study by Industrial Economics Inc. shows that a $19 million order for a new scrubber will immediately fund 77 to 91 new jobs for a year constructing and installing the new equipment. It will also create 16 permanent jobs to operate the new equipment (Price et al. 2010).

9.2.3.4 Impacts on Profitability and Plant Closures

In other cases, analysts may assess the impacts of rules on the profitability of specific firms or industry segments and identify potential plant closures based on a financial analysis. If partial or full plant closures are projected, then it is important to consider whether the production lost at the affected facilities will be shifted to other existing plants or to new sources, or simply vanish. If excess industry capacity exists in the baseline and facilities are able to operate profitably while complying with the rule, then these facilities may expand production to meet the demand created by the loss of plants that are no longer able to operate profitably. Some surviving plants could experience increases in production, capacity utilization, and profits even though they are subjected to regulatory requirements, if their competitors face even greater cost increases.

9.2.3.5 Impacts on Related Industries

The economic and financial impacts of regulatory actions spread to industries and communities that are linked to the regulated industries and to the pollution abatement industries, resulting in indirect business impacts. To build scrubbers, the environmental protection industry will order more steel. If a plant produces less, it will order fewer raw materials. These indirect impacts may include employment and income gains and losses.

Although in principle every economic entity can be thought of as having a connection with every other entity, practical considerations usually require an analysis of indirect impacts for a manageable subset of economic entities that are most strongly linked to the regulated entity. In addition to considering major customers and specialized suppliers of the affected industry, it is important to consider less obvious but potentially significant links, such as basic suppliers like electricity generators.

For these reasons, the analysis of linkages should use a framework that thoroughly measures indirect as well as direct linkages. Whatever the approach, the goal of the analysis is to measure how employment, competitiveness, and income are likely to change for related entities and households given a certain amount of employment, competitiveness, and income in a regulated market.

9.2.3.6 Impacts on Economic Growth and Technical Inefficiency

While regulatory interventions can theoretically lead to macroeconomic impacts, such as growth and technical efficiency, such impacts may be impossible to observe or predict. In some cases, however, it may be feasible to use macroeconomic models to evaluate the regulatory impact on GDP, factor payments, inflation, and aggregate employment. For regulations that are expected to have significant impacts in a particular region, use of regional models, either general equilibrium or other regionally-based models, may be valuable.[17]

Typically in regulatory impact analyses some macroeconomic regulatory effects go unquantified due to analytic constraints. For example, price changes induced by a regulation can lead to technical inefficiency because firms are not choosing the production techniques that minimize

17 Chapter 8 discusses the use of regional modeling.

the use of labor and other resources in the long run. However, measuring these effects can be difficult due to data or other analytical limitations.

9.2.3.7 Impacts on Industry Competitiveness

Regulatory actions that substantially change the structure or conduct of firms can produce indirect impacts by changing the competitiveness of the regulated industry, as well as that of linked industries.[18] An analysis of impacts on competitiveness begins by examining barriers to entry and market concentration, and by answering the following two key questions:

- **Does the regulation erect entry barriers that might reduce innovation by impeding new entrants into the market?** High sunk costs associated with capital costs of compliance or compliance determination and familiarization would be an entry barrier attributable to the regulation. Sunk costs are fixed costs that cannot be recovered in liquidation; they can be calculated by subtracting the liquidation value of assets from the acquisition cost of assets facing a new entrant, on an after-tax basis.[19] Lack of access to debt or equity markets to finance fixed costs of entering the market can also present entry barriers, even if none of the fixed costs are sunk costs. However, if financing is available and fixed costs are recoverable in liquidation, the magnitude of fixed costs alone may not be sufficient to be a barrier to entry.
- **Does the regulation tend to create or enhance market power and reduce the economic efficiency of the market?** Important measures of competitiveness of an industry are degrees of horizontal and vertical integration (i.e., concentration) between both buyers and sellers in the baseline compared to post-compliance. If an industry becomes more concentrated as a result of the regulation then there are fewer firms within the industry. In this case, market power will be concentrated in the hands of a few entities, which may result in a less efficient market than before the regulation. Closely related to concentration, product differentiation may occasionally either increase or decrease due to a regulatory action. A regulation may result in less product differentiation due to restrictions on production. This could mean that market power is more concentrated among the firms that manufacture the product.

9.2.3.8 Impacts on Energy Supply, Distribution, or Use

EO 13211 requires agencies to prepare a Statement of Energy for "significant energy actions," which are defined as significant regulatory actions (under EO 12866) that also are "likely to have a significant adverse effect on the supply, distribution, or use of energy."[20] These significant adverse effects are defined as:

- Reductions in crude oil supply in excess of 10,000 barrels per day;
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of 5 million tons per year;
- Reductions in natural gas production in excess of 25 million mcf per year;
- Reductions in electricity production in excess of 1 billion kilowatt-hours per year or in excess of 500 megawatts of installed capacity;
- Increases in energy use required by the regulatory action that exceed any of the thresholds above;
- Increases in the cost of energy production in excess of 1 percent;
- Increases in the cost of energy distribution in excess of 1 percent; or
- Other similarly adverse outcomes.

For actions that may be significant under EO 12866, particularly for those that impose requirements on the energy sector, analysts must be prepared to examine the energy effects listed above.

18 See Jaffe et al. (1995) for an overview.

19 Sunk costs are sometimes referred to as exit barriers.

20 See Section 2.1.6 for EPA and OMB's guidance on EO 13211.

9.2.4 Detailing Impacts on Governments and Not-for-Profit Organizations

Section 9.3.5 discusses how to measure the impact of regulations and requirements on private entities, such as firms and manufacturing facilities. When dealing with private entities, an important focus is on measures that assess changes in profits (or proxy measures of profit). This section describes impact measures for situations where profits and profitability are not the focus of the analysis. Rather, the ultimate measure of impacts is the ability of the organization or its residents to pay for the requirements. Many of the same questions apply:

- Which entities are affected and what are their characteristics?
- To what extent does the regulation increase operating costs?
- To what extent does the regulation impact operating procedures?
- Does the regulation change the amount and/ or quality of the goods and services provided?
- Can the entity raise the necessary capital to comply with the regulation?
- Does the regulation change the entity's ability to raise capital for other projects?

EPA regulations can affect governments and not-for-profit organizations in at least three significant ways. First, a regulation may directly impose requirements on the entity, such as imposing water pollution requirements for publicly-owned wastewater treatment works, or initiating air pollution restrictions that affect municipal bus systems or power plants. Second, a regulation may impose implementation and enforcement costs on government agencies. Finally, a regulation may impose indirect costs. For example increased unemployment due to reduced production (or even plant closure) could result in less tax revenues in a community.

9.2.4.1 Direct Impacts on Government and Not-for-Profit Entities

Direct impact measures can fall into two categories:

- Those that measure the impact itself in terms of the relative size of the costs and the burden it places on residents; and
- Those that measure the economic and financial conditions of the entity that affect its ability to pay for the requirements.

For each category, there are several types of measures that can be used either as alternatives or jointly to illuminate aspects of the direct impacts.

Measuring the relative cost and burden of the regulations

There are three commonly used approaches to measuring the direct burden of a rule; all involve calculating the annualized costs of complying with the regulation. For government entities the three approaches are:

- **Annualized compliance costs as a percentage of annual costs for the affected service.** This measure defines the impact as narrowly as possible and measures impacts according to the increase in costs to the entity. In practice, EPA has often defined compliance costs that are less than 1 percent of the current annual costs of the activity as placing a small burden on the entity.
- **Annualized compliance costs as a percentage of annual revenues of the governmental unit.** The second measure corresponds to the commonly used private-sector measure of annualized compliance costs as a percentage of sales. Referred to as the "Revenue Test," it is one of the measures suggested in the RFA Guidance (U.S. EPA 2006b).
- **Per household (or per capita) annualized compliance costs as a percentage of median household (or per capita) income.** The third measure compares the annualized costs to the ability of residents to pay for the cost increase. The ability of residents to pay for the costs affects government entities because fees and taxes on residents fund these entities. To the extent that residents can (or cannot) pay for the cost increases, government entities will

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be impacted. Commonly referred to as the "Income Test," this measure is described in the RFA Guidance (U.S. EPA 2006b) and the EPA Office of Water *Interim Economic Guidance for Water Quality Standards: Workbook* (U.S. EPA 1995a).[21] Costs can be compared to either median household or median per capita income. In calculating the per household or per capita costs, the actual allocation of costs needs to be considered. If the costs are paid entirely through property taxes, and the community is predominately residential, then an average per household cost is probably appropriate. If some or all of the costs are allocated to users (e.g., fares paid by bus riders or fees paid by users for sewer, water, or electricity supplied by municipal utilities), then a more narrow measure may be appropriate. If some of the costs are borne by local firms, then that portion of the costs should be analyzed separately.

There are two commonly used impact measures for *not-for-profit entities:* (1) annualized compliance costs as a percentage of annual operating costs; and (2) annualized compliance costs as a percentage of total assets. The first is equivalent to the first of the impact measures described for government entities, measuring the percentage increase in costs that would result from the regulation being analyzed. The second is a more severe test, measuring the impacts if the annualized costs are paid out of the institution's assets.

Measuring the economic and financial health of the community or government entity

The second category of direct impact measures examines the economic and financial health of the community involved, since this affects its ability to finance or pay for expenditures required by a program or rule. A given cost may place a much heavier burden on a poor community than on a wealthy one of the same size. As with the impact measures described above, there are three categories of economic and financial condition measures:

- **Indicators of the community's debt situation.** Debt indicators are important because they measure both the ability of the community to absorb additional debt (to pay for any capital requirements of the rule) and the general financial condition of the community. While several debt indicators have been developed and used, this section describes two common indicators. One measure is the government entity's bond rating. Awarded by companies such as Moody's and Standard & Poor's, bond ratings evaluate a community's credit capacity and thus reflect the current financial conditions of the government body.[22] A second frequently used measure is the ratio of overall net debt to the full market value of taxable property in the community, i.e., debt to be repaid by property taxes. Overall net debt should include the debt of overlapping districts. For example, a household may be part of a town, regional school district, and county sewer and water district, all of which have debt that the household is helping to pay.[23] See Table 9.3 for interpretations of the values for these measures. **Debt measures are not always appropriate.** Some communities, especially small ones, may not have a bond rating. This does not necessarily mean that they are not creditworthy; it may only mean that they have not had an occasion recently to borrow money in the bond market. If the government entity does not rely on property taxes, as may be the case for a state government or an enterprise district, then the ratio of

21 For example, in the water guidance and other EPA Office of Water analyses compliance costs are considered to have little impact if they are less than 1 percent of household income. Compliance costs greater than 2 percent are categorized as a large impact, and a range from 1 to 2 percent fall into a gray area and are considered to have an indeterminate impact.

22 The indicators and benchmark values in Table 9.3 are drawn from *Combined Sewer Overflows — Guidance for Financial Capability Assessment and Schedule Development*, which discusses how to assess the feasibility of systems being able to comply with rules (U.S. EPA 1997b). These are general benchmarks that may prove useful in assessing financial stability in an EIA.

23 An alternative to the net debt as percent of full market value of taxable property is the net debt per capita. Commonly used benchmarks for this measure are: net debt per capita less than $1,000 indicates a strong financial condition, between $1,000 and $3,000 indicates a mid-range or gray area, and greater than $3,000 indicates a weak financial condition.

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Table 9.3 - Indicators of Economic and Financial Well-Being of Government Entities

Indicator	Weak	Mid-Range	Strong
Bond rating	Below BBB (S&P) Below Baa (Moody's)	BBB (S&P) Baa (Moody's)	Above BBB (S&P) Above Baa (Moody's)
Overall net debt as percent of full market value of taxable property	Above 5%	2% - 5%	Below 2%
Unemployment rate	More than 1 percentage point above national average	Within 1 percentage point of national average	More than 1 percentage point below national average
Median household income	More than 10% below the state median	Within 10% of the state median	More than 10% above the state median
Property tax revenue as percent of full market value of taxable property	Above 4%	2% - 4%	Below 2%
Property tax collection rate	Less than 94%	94% - 98%	More than 98%

Source: U.S. EPA 1997b

debt to full market value of taxable property is not relevant. Information on debt and assessed property values are available from the financial statement of each community. The state auditor's office is likely to maintain this information for all communities within a state.

- **Indicators of the economic/financial condition of the households in the community.** There are a wide variety of household economic and financial indicators. Commonly used measures are the unemployment rate, median household income, and foreclosure rates. Unemployment rates are available from the Bureau of Labor Statistics. Median household income is available from the U.S. Census Bureau. Benchmark values for these and other measures are presented in Table 9.3.
- **Financial management indicators.** This category consists of indicators that gauge the general financial health of the community, as opposed to the general financial health of the residents. Because most local communities rely on property taxes as their major source of revenues, there are two ratios that provide an indicator of financial strength. First, property tax revenue as a percentage of the full market value of taxable property indicates the burden that property taxes place on the community.[24] Second, the property tax collection rate gauges the efficiency with which the community's finances are managed, and indirectly whether the tax burden may already be excessive. As the property tax burden on taxpayers increases, they are more likely to avoid paying their taxes or to pay them late.

Measuring the financial strength of *not-for-profit* entities includes assessing:

- The size of the entity's reserves;
- How much debt the entity already has and how its annual debt service compares to its annual revenues; and
- How the entity's fees or user charges compare with the fees and user charges of similar institutions.

As with government entities, this analysis is meant to judge whether the entity is in a strong or weak financial position to absorb additional costs.

9.2.4.2 Administrative, Enforcement, and Monitoring Burdens on Governments

Many EPA programs require effort on the part of different levels of government for administration,

24 If the state caps local property taxes (e.g., Proposition 13 in California or Proposition 2½ in Massachusetts) then it may be relevant to examine the ratio of property tax to the allowed level of the taxes.

enforcement, and monitoring. These costs must be included when estimating impacts of a regulation to comply with UMRA and to calculate the full social costs of a program or rule. See Chapter 8 for more information on government regulatory costs.

9.2.4.3 Induced Impacts on Government Entities

The induced impacts on government entities should also be considered. For example, a manufacturing facility may reduce or suspend production in response to a regulation, thus reducing the income levels of its employees. In turn, these reductions will spread through the economy by means of changes in household expenditures. These induced impacts include the multiplier effect, in which loss of income in one household results in less spending by that household and therefore less income in households and firms associated with goods previously purchased by the first household.

Decreased household and business income can affect the government sector by reducing tax revenues and increasing expenditures on income security programs (the automatic stabilizer effect), employment training, food and housing subsidies, and other fiscal line items. Due to wide variation in these programs and in tax structures, estimating public sector impacts for a large number of government jurisdictions can be prohibitively difficult.

On the other hand, compliance expenditures increase income for businesses and employees that provide compliance-related goods and services. These income gains also have a multiplier effect, offsetting some of the induced losses in tax revenue and increases in government expenditures identified above. As some linkages may be more localized than others, it is important to clearly identify where the gains and losses occur.

9.2.5 Detailing Impacts on Small Entities

The Regulatory Flexibility Act, as amended by the Small Business Regulatory Fairness Act of 1996 (RFA), and Section 203 of the Unfunded Mandates Reform Act of 1995 (UMRA) require agencies to consider a proposed regulation's economic effects on small entities, specifically, small businesses, small governmental jurisdictions, or small not-for-profit organizations. The definition of "small" for each of these entities is described below. For guidance on when it is necessary to examine the economic effects of a regulation under the RFA or UMRA, analysts should consult EPA guidelines on these administrative laws (U.S. EPA 2006b and U.S. EPA 1995b, respectively). In general, the Agency must fulfill certain procedural and/or analytical obligations when a rule has a "significant impact on a substantial number of small entities" (abbreviated as SISNOSE) under the RFA or when a rule might "significantly" or "uniquely" affect small governments under Section 203 of UMRA.

9.2.5.1 Small Businesses

The RFA requires agencies to begin with the definition of small business that is contained in the Small Business Administration's (SBA) small business size standard regulations.[25] The RFA also authorizes any agency to adopt and apply an alternative definition of small business "where appropriate to the activities of the Agency" after consulting with the Chief Counsel for Advocacy of the SBA and after opportunity for public comment. The agency must also publish any alternative definition in the *Federal Register* (U.S. EPA 2006b).

The analytical tasks associated with complying with the RFA include a screening analysis for SISNOSE. If the screening analysis reveals that a rule *cannot* be certified as having no SISNOSE, then the RFA requires a regulatory flexibility analysis be conducted for the rule, which includes a description of the economic impacts on small entities. Impacts on small businesses are generally assessed by estimating the direct compliance costs and comparing them to sales or revenues. Because an estimate of direct compliance costs tends to be a conservatively low estimate of a regulation's impact, further analysis examining the impacts discussed in Section 9.3.3 (specifically in relation

25 The current version of SBA's size standards can be found at http://www.sba.gov/size (accessed March 13, 2011).

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to small businesses) may provide additional information for decision makers.[26]

9.2.5.2 Small Governmental Jurisdictions

The RFA defines a small governmental jurisdiction as the government of a city, county, town, school district, or special district with a population of less than 50,000. Similar to the definition of small business, the RFA authorizes agencies to establish alternative definitions of small government after opportunity for public comment and publication in the *Federal Register*. Any alternative definition must be "appropriate to the activity of the Agency" and "based on such factors as location in rural or sparsely populated areas or limited revenues due to the population of such jurisdiction" (U.S. EPA 2006b). Under the RFA, economic impacts on small governments are included in the SISNOSE screening analysis, and any required regulatory flexibility analysis for a rule.

UMRA uses the same definition of small government as the RFA with the addition of tribal governments. Section 203 of UMRA requires the Agency to develop a "Small Government Agency Plan" for any regulatory requirement that might "significantly" or "uniquely" affect small governments. In general, "impacts that may significantly affect small governments include — but are not limited to — those that may result in the expenditure by them of $100 million [adjusted annually for inflation] or more in any one year." Other indicators that small governments are uniquely affected may include whether they would incur the higher per-capita costs due to economies of scale, a need to hire professional staff or consultants for implementation, or requirements to purchase and operate expensive or sophisticated equipment.[27] See Section 9.3.4 for information on measures of impacts to governments in general.

26 See Agency guidance (U.S. EPA 2006c) for details on complying with the RFA.

27 Guidance on complying with Section 203 of UMRA, "Interim Small Government Agency Plan," is available on EPA's intranet site, ADP Library at http://intranet.epa.gov/adplibrary/statutes/umra.htm (accessed March 21, 2011, internal EPA document)

9.2.5.3 Small Not-for-Profit Organizations

The RFA defines a small not-for-profit organization as an "enterprise which is independently owned and operated and is not dominant in its field." Examples may include private hospitals or educational institutions. Here again, agencies are authorized to establish alternative definitions "appropriate to the activities of the Agency" after providing an opportunity for public comment and publication in the *Federal Register.* Under the RFA, economic impacts on small not-for-profit organizations are included in the SISNOSE screening analysis, and if required, the regulatory flexibility analysis for a rule. See Section 9.3.4 for more information on measuring impacts on not-for-profit organizations in general.

9.3 Approaches to Modeling in an Economic Impact Analysis

This section returns to the methods for estimating social costs covered in Chapter 8, adding more insight on their application to EIA. The reader should refer to Chapter 8 for a more in-depth discussion. As noted above, the analytic assumptions used for the EIA of a particular regulation should be consistent with those used for the corresponding BCA.

9.3.1 Direct Compliance Costs

The simplest approach to measuring the economic impacts is to estimate and verify the private costs of compliance. This is necessary regardless of whether the entities affected are for-profit, governmental, communities, or not-for-profit. Direct compliance costs are considered the most conservative estimate of private costs and include annual costs (e.g., operation and maintenance of pollution control equipment), as well as any capital costs. Direct compliance costs do not include implicit costs.

Verifying the compliance cost estimates entails two steps. First, the full range of responses to the rule needs to be identified, including pollution prevention alternatives and any differences in response across sub-sectors and/or geographic regions. Second, the costs for each response need to be examined to determine if all elements are included and if the costs are consistent within a given base year. To ensure consistency across years, either a general inflation factor, such as the GDP implicit price deflator, or various cost indices specific to the type of project should be used.[28] The base year and indexing procedure should be stated clearly.

Implicit costs that do not represent direct outlays may be important. The cost estimates should include such elements as production lost during installation, training of operators, and education of users and citizens on programs involving recycling of household wastes. The cost of acquiring a permit includes the permit fee as well as the lost opportunities during the approval process. Likewise, the cost of having a car's emissions inspected is not so much the fee as it is the value of a registrant's time.

In addition, it is important to recognize that these expenditures may have other benefits and costs. For example, they may confer tax breaks (complying with regulations may be a tax deductible expense) and the new capital may be more productive than the old capital. These "offsets" should be considered, particularly when they may be substantial.

There are several issues analysts should consider when estimating the direct compliance costs of environmental polices for an EIA. These include:

- **Before- versus after-tax costs.** For businesses, the cost of complying with regulations is generally deductible as an expense for income tax purposes. Therefore, the effective burden is reduced for taxable entities because they can reduce their taxable income by the amount of the compliance costs. The effect of a regulation on profits is therefore measured by after-tax compliance costs. Operating costs are generally fully deductible as expenses in the year incurred. Capital investments associated with compliance must generally be depreciated.[29] In most cases, communities, not-for-profits, and governments do not benefit from reduced income taxes that can offset compliance costs. Therefore, adjustments to cost estimates, annualization formulas, and cost of capital calculations required to calculate after-tax costs should not be used in analyses of impacts on governments, not-for-profits, and households.
- **Transfers.** Some types of compliance costs incurred by the regulated parties may represent transfers among parties. Transfers, such as payments for insurance or payments for marketable permits, do not reflect use of economic resources. However, individual private cost estimates used in the EIA include such transfers.[30]
- **Discounting.** Compliance costs often vary over time, perhaps requiring initial capital investments and then continued operating costs. To estimate impacts, the stream of costs is generally discounted to provide a present value of costs that reflects the time value of money.[31] In contrast to social costs and benefits, which are discounted using a social discount rate, private costs are discounted using a rate that reflects the regulated entity's cost of capital.[32] The private discount rate used will generally exceed the social discount rate by an amount that reflects the risk associated with the regulated entity in question. For firms, the cost of capital may also be determined by their ability to deduct debt from their tax liability.

28 The GDP implicit price deflator is reported by the U.S. DOC, BEA in its *Survey of Current Business* (http://www.bea.gov/scb/index.htm). The annual *Economic Report of the President*, Executive Office of the President, is another convenient source for the GDP deflator, available at www.gpoaccess.gov/eop/ (accessed March 13, 2011).

29 Current federal and state income tax rates can be obtained from the Federation of Tax Administrators, *State Tax Rates & Structure*, available at http://www.taxadmin.org/fta/rate/default.html (accessed January 31, 2011).

30 These transfers cancel out in a BCA. In an EIA the distribution of results is important, therefore the transfers are included.

31 The present value of costs can then be annualized to provide an annual equivalent of the uneven compliance cost stream. Annualized costs are also discussed in Chapter 6.

32 While the discount rate differs, the formula used to discount private costs is the same as used for social costs. See Chapter 6 for details.

- **Annualized costs.** Annualizing costs involves calculating the annualized equivalent of the stream of cash flows associated with compliance over the period of analysis. This provides a single annual cost number that reflects the various components of compliance costs incurred over this period. The annual value is the amount that, if incurred each year over the selected time period, would have the same present value as the actual stream of compliance expenditures. Annualized costs are therefore a convenient compliance cost metric that can be compared with annual revenues and profits. It is important to remember that using annualized costs masks the timing of actual compliance outlays. For some purposes, using the underlying compliance costs may be more appropriate. For example, when assessing the availability of financing for capital investments, it is important to consider the actual timing of capital outlays.
- **Fixed versus variable costs.** Some types of compliance costs vary with the size of the regulated enterprise, such as quantity of production. Other components of cost may be fixed with respect to production or other size measures, such as the costs involved in reading and understanding regulatory requirements. Requirements that impose high fixed costs will impose a higher cost per unit of production on smaller firms than on larger firms. It is important that the effects of any economies of scale are reflected in the compliance costs used to analyze economic impacts.[33] Using the same average annualized cost per unit of production for all firms may mask the importance of such fixed costs and understate impacts on small entities.

9.3.2 Partial Equilibrium Models

A partial equilibrium framework is an alternative way to examine distributional effects when impacts are limited to a few directly and indirectly affected output markets only. For example, a regulation may increase the costs of producing a particular chemical. Partial equilibrium models can be used to examine the distribution of these changes across directly affected industries, and a small number of indirectly affected entities (e.g., upstream and downstream). Partial equilibrium models can range in size from an analysis that estimates compliance costs for the affected industry only (i.e., direct compliance costs) to multi-market models encompassing several directly and indirectly affected sectors.

If a single-market partial equilibrium model is the only information source available for an analysis of impacts, then it may be possible to adopt further assumptions and acquire additional data to approximate impacts on other areas of concern. This may include deriving ratios to aggregate changes in order to assign these changes to specific regions or sectors. These new assumptions should be consistent with those used for the corresponding BCA.

Multi-market models consider the interactions between a regulated market and other important related markets (outputs and inputs), requiring estimates of elasticities of demand and supply for these markets as well as cross-price-elasticities (also found in CGE models). These models are best used when potential impacts on related markets might be considerable, but more complete modeling using a CGE framework may not be available or practical. Partial equilibrium models may also be more appropriate for regionally based or resource specific regulations that are too specific for more aggregated CGE models.[34] Care should be taken, however, to avoid double counting, particularly when both upstream and downstream entities are affected and included in the partial equilibrium analysis. If cost increases due to a regulation are passed on from the upstream to the downstream businesses then analysts should take care not to include impacts on both sets of entities to avoid double counting results.

33 Economies of scale characterize costs that decline on a per unit basis as the scale of the operation increases.

34 See the discussion of multi-market modeling in Chapter 8 and Just et al. (1982).

9.3.3 Computable General Equilibrium Models

CGE models are particularly effective in assessing resource allocation and welfare effects. These effects include the allocation of resources across sectors (e.g., employment by sector), the distribution of output by sector, the distribution of income among factors, and the distribution of welfare across different consumer groups, regions, and countries. As noted in Chapter 8, for example, regulations in the electric utility sector are likely to cause electricity prices to increase. The price increase will affect all industries that use electricity as an input to production (i.e., most industries), as well as households. A CGE model can assess the distribution of the changes in production and consumption that result. By design, the basic capacity to describe and evaluate these sorts of impacts exists to some extent within every CGE model. More detailed impacts (e.g., affects on a particular facility) or impacts of a particular kind (e.g., affects on drinking water) will require a more complex and/or tailored model formulation and the data to support it.

The simplest CGE models generally include a single representative consumer, a few production sectors, and a government sector, all within a single-country, static framework. Additional complexities can be specified for the model in a variety of ways. Consumers may be divided into different groups by income, occupation, or other socioeconomic criteria. Producers can be disaggregated into dozens or even hundreds of sectors, each producing a unique commodity. The government, in addition to implementing a variety of taxes and other policy instruments, may provide a public good or run a deficit. CGE models can be international in scope, consisting of many countries or regions linked by international flows of goods and capital. The behavioral equations that characterize economic decisions may take on simple or complex functional forms. The model can be solved dynamically over a long time horizon, incorporating intertemporal decision making on the part of consumers or firms. These choices have implications for the treatment of savings, investment, and the long-term profile of consumption and capital accumulation.

As effective as CGE models can be for looking at long-term resource allocation issues, they have limitations for the kinds of impact analyses described above. CGE models assume that markets clear in every period and often do not consider short-term adjustment costs, such as lingering unemployment. The analyst should be careful to select a model that does not assume away the underlying issue addressed by the distribution analysis. Moreover, a CGE model may not be feasible or practical to use when data and resources are limited or when the scope of expected significant market interactions is limited to a subset of economic sectors. In such instances a partial equilibrium model can be adopted as a more appropriate alternative to a CGE model.[35] Finally, it is worth noting that while CGE modeling is complex, the effort may be worthwhile when data are available and the distributional impacts are likely to be widespread.

35 For a discussion of CGE analysis see Chapter 8 and Dixon et al. (1992).

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