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By Environmental Improvement Board at 6:20 pm, Jul 28, 2021

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

COMMERCIAL DISPOSAL GROUP'S STATEMENT OF INTENT TO PRESENT DIRECT TECHNICAL TESTIMONY

Pursuant to the June 8, 2021 Order of Hearing Determination and Hearing Officer Appointment and 20.1.2.302 NMAC, NGL Energy Partners LP ("NGL"), Solaris Water Midstream, LLC ("Solaris"), OWL SWD Operating, LLC ("OWL"), Goodnight Midstream, LLC ("Goodnight"), and 3 Bear Energy, LLC ("3 Bear"), (collectively the "Commercial Disposal Group" or the "Group") gives notice that it intends to present direct technical testimony in the hearing in this matter currently scheduled to begin September 20, 2021, and continuing day-to-day until completed.

Each of the members of the Commercial Disposal Group has commercial operations in New Mexico for the recycling and underground injection of produced water. Members of the Group either conduct pipeline pig launching and receiving operations or could be affected by the proposed pigging rules in the future. The New Mexico Environment Department's ("NMED") Oil and Gas Sector - Ozone Precursor Pollutants proposed rule ("Proposed Rule") will directly and negatively impact each member of the Group. More specifically, the Group is concerned that the language of the Proposed Rule appears crafted to address important concerns at sites owned and operated by oil and gas producers, but that in many cases this language does not fit operations at commercial produced water disposal facilities. For this reason, the Proposed Rule imposes onerous requirements that are often technically infeasible or very expensive, with little apparent environmental benefit. The Group is concerned that as written the Proposed Rule will likely hinder further investment in and operation of important produced water recycling, reuse and treatment operations in New Mexico. The Group believes the Department's regulations and policies should promote the recycling and reuse of produced water as a valuable resource. For these reasons and as further explained in the attached direct testimony, the Commercial Disposal Group respectfully requests that NMED consider its comments and suggested alternatives to certain provisions of Section 20.2.50.126 (Produced Water Management Units), as well as certain monitoring-related requirements in Sections 20.2.50.112 (General Provisions), 20.2.50.120 (Hydrocarbon Liquid Transfers), and . 20.2.50.123 (Storage Vessels), in order to avoid unintended negative impacts to the commercial produced water recycling and disposal industry and to the State of New Mexico.

The Commercial Disposal Group submits to the Board the following information pursuant to 20.1.1.302:

1. Entity for whom the witnesses will testify: The witnesses identified herein will testify on behalf of NGL, Solaris, OWL, Goodnight, and 3 Bear.
2. Identity and qualifications of witnesses and copy of direct testimony:
    a. Il Kim. Il Kim is a Senior Air Permitting Engineer at NGL Energy Partners LP who has over 10 years of experience at various consulting and oil and gas firms as an air quality technical advisor for oil and gas operators. He has managed air quality permitting, compliance programs, and diligence reviews for numerous environmental projects to ensure regulatory requirements are met. He holds a

Bachelor of Science degree in Engineering. A copy of Mr. Kim's direct testimony, which includes his CV, is attached hereto as **Attachment A**.

b. Ashley Campsie. Ashley Campsie has over 25 years of experience in the public and private environmental sectors, a majority of which has been focused on developing a specialty in air quality permitting and compliance for the oil and gas industry. Her past experience includes working as a permit writer for the Colorado Air Pollution Control Division, an environmental engineer for a large midstream oil and gas company, a senior project engineer/manager for CH2M Hill and serving for six years as a commissioner on the Colorado Air Quality Control Commission. She now has her own independent environmental consulting firm specializing in air quality support. Ashley is a Colorado licensed professional engineer and has a Bachelor of Science degree in chemical engineering with an environmental emphasis. A copy of Ms. Campsie's direct testimony, which includes her CV, is attached hereto as **Attachment B**.

c. Lori Marquez. Lori Marquez in an engineer with over 30 years of experience in the environmental and design engineering fields. She has extensive air quality experience, including permitting, compliance, and emission inventories for minor, Title V, and PSD sources across multiple states and industries. She holds a Bachelor of Science degree in Electrical Engineering and a Master of Science Degree in Environmental Sciences. A copy of Ms. Marquez's direct testimony, which includes her CV, is attached hereto as **Attachment C**.

d. Jill Cooper. Jill Cooper has a degree in law with an emphasis on environmental and regulatory law and has worked in the oil and gas industry for almost 30 years.

A majority of her experience is with air and water permitting, compliance, and regulatory efforts for regulatory agencies, companies (inhouse), and clients. A copy of Ms. Cooper's direct testimony, which includes her CV, is attached hereto as **Attachment D**.

e. Greg Jones. Greg Jones is an Air Compliance Specialist with over ten years of drilling, completion and producing engineering and operations experience in United States onshore and offshore energy development environments. In addition, he has over twenty years of multimedia environmental engineering and compliance support experience, including the last fifteen years of providing air quality permitting and compliance support to both upstream and midstream energy operations located within multiple operating basins. He is a Professional Engineer licensed in Louisiana and Texas who holds degrees in petroleum and civil engineering from Louisiana Technical University. A copy of Mr. Jones' direct testimony, which includes his CV< is attached hereto as **Attachment E**.

3. Recommended modifications: A copy of the Group's recommended modifications to the proposed new regulation for the oil and gas sector—ozone precursor pollutants is included herewith as Exhibit 1 to Attachment F.
4. Exhibits: Copies of exhibits and a complete list of exhibits the Group anticipates offering into evidence in this matter is attached to this Notice as **Attachment F**. The group reserves the right to introduce and move for admission of any other exhibit in support of rebuttal or additional direct testimony at the hearing.

Respectfully submitted this 28th day of July 2021,

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By: *s/ Christopher J. Neumann*
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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing STATEMENT OF INTENT TO PRESENT DIRECT TECHNICAL TESTIMONY was filed via electronic mail with the New Mexico Environment Department and served via electronic mail to the following parties on this 28th day of July, 2021:

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/s/Robin M. Aragon

APPENDIX A

DIRECT TESIMONY OF IL KIM

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STATE OF NEW MEXICO

ENVIRONMENTAL IMPROVEMENT BOARD

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

TESTIMONY OF IL KIM

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A: Il Kim. 865 North Albion Street, Suite 400, Denver, Colorado 80220.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: NGL Energy Partners LP.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of NGL Energy Partners LP (“NGL”), Solaris Water Midstream, LLC (“Solaris”), OWL SWD Operating, LLC (“OWL”), Goodnight Midstream, LLC (“Goodnight”), and 3 Bear Energy, LLC (“3 Bear”), which I may collectively refer to as the “Commercial Disposal Group” or the “Group.”

Q: PLEASE STATE BRIEFLY THE NATURE OF THESE BUSINESSES.

A: As relevant to the New Mexico Environment Department’s (“NMED”) proposed ozone precursor rule “proposed rule”), NGL, Solaris, OWL, Goodnight, and 3 Bear all have commercial salt water disposal (SWD) operations in the state of New Mexico that provide environmental services to the exploration and production ("E&P") sector of the oil and gas industry through recycling and/or underground injection of produced water.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the Commercial Disposal Group's overall operations and how the NMED proposed rules would impact the Group's operations. Although the Group provides produced water services to E&P companies, its member's facilities are not E&P facilities and they do not operate like E&P facilities. The failure of certain provisions in the proposed rule to make this distinction creates compliance issues that will negatively impact the Group's businesses, thwart environmental benefits, and impede New Mexico's goal of enhancing re-use and recycling of treated produced water. In my testimony, I will propose some practical alternatives that will achieve the purposes of the proposed rule, protect and enhance the environment, and enable the Group members to responsibly conduct their businesses.

Q: DO YOU OPPOSE NMED'S PROPOSED OZONE PRECURSOR RULES?

A: I support many provisions in NMED's proposed rules but take exception to two provisions in particular which will directly and negatively impact each member of the Commercial Disposal Group's operations for recycling and underground injection of produced water. Specifically, my testimony will address the proposed rules relating to (i) hydrocarbon liquid transfers and (ii) storage vessels.

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH THE PROPOSED OZONE PRECURSOR RULES.

A: The provisions I am concerned about do not take into consideration the differences between commercial produced water facilities and exploration and production facilities. The Group provides services for disposal of produced water at underground injection well facilities and recycling of produced water at produced water management unit facilities. When applied to these types of

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facilities, the provisions of the proposed rule impose requirements that are unduly burdensome, prohibitively costly, and/or technically infeasible.

Q: HAVE YOU PREPARED A STATEMENT OF YOUR EXPERIENCE AND QUALIFICATIONS?

A. Yes. I am a Senior Air Permitting Engineer at NGL Energy Partners LP with over 10 years of experience at various consulting and oil and gas firms as an air quality technical advisor for oil and gas operators. I have managed air quality permitting, compliance programs, and diligence reviews for numerous environmental projects to ensure regulatory requirements are met. I hold a Bachelor of Science degree in Engineering form Arizona State University and a Master of Business Administration in Energy from University of Wyoming. A statement setting forth my relevant experience and qualifications is attached as Attachment A.

II. COMMERCIAL DISPOSAL GROUP'S OPERATIONS

Q: DESCRIBE THE GROUP MEMBERS' RELEVANT OPERATIONS RELATING TO RECYCLING AND UNDERGROUND INJECTION OF PRODUCED WATER.

A: Each member of the Commercial Disposal Group has operations in New Mexico for the recycling and/or underground injection of produced water. Most of the Group have facilities that operate Produced Water Management Units ("PWMUs") at which millions of barrels of produced water are recycled each year and returned to oil and gas producers for use in hydraulic fracturing and other reuse operations. These recycle ponds are several acres in size and often have the capacity to contain several hundred thousand barrels of water. The water sent to these PWMUs will have gone through pretreatment to reduce emissions. A schematic of a Typical Produced Water Management Unit Design is attached as Attachment B. To date, the Group has a total of thirteen recycling facilities in New Mexico and several more in the planning stages. In 2020, the Group members recycled over 18.8 million barrels of water. In the first six months of 2021, the Group

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recycled over 16.7 million barrels. If the produced water/brine water is not recycled by the Group members, they will have to use freshwater for their water needs.

Produced water that is not recycled by the Group is treated and responsibly disposed of through the U.S. Environmental Protection Agency's underground injection control program, administered by the New Mexico Energy and Minerals Department, Oil Conservation Division. Though these facilities look like typical E&P facilities, the operations and fluids at the facilities are much different. The disposal well facilities receive produced water from operator's production and drilling operations. These facilities do not produce oil/gas/water. The produced water the Group members receive is low volatility, post-flash, and has gone through separation, processing, and treatment at our customers' sites. At these facilities the water is separated from the oil, the oil is trucked off site, and the water is injected into an injection well. The oil that is separated from the water at the Group's facilities is also different than the oil produced from and E&P sites. It is less volatile and is considered "dead" oil because it has limited flashing/emission potential. A schematic of a Typical Disposal Well Operation is attached as Attachment C.

III. <u>HYDROCARBON LIQUID TRANSFERS</u>

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.120 NMAC AS PROPOSED?

A: Yes.

Q: **PLEASE SUMMARIZE YOUR CONCERNS WITH 20.2.50.120 NMAC.**

A: Section 120 imposes emission control requirements on hydrocarbon liquid transfers in a wide range of contexts. This provision requires the owner or operator of a hydrocarbon liquid transfer operation to control volatile organic compound ("VOCs") emissions by at least ninety-eight percent when transferring liquid between storage vessels and transfer vessels. The proposed rule fails to take into account the operational differences between Group's facilities and oil and gas E&P facilities. The Group's hydrocarbon load outs from a facility might occur once a week or even once a month while E&P facilities load out hydrocarbons numerous times in a day. The oil being loaded is also different from the oil and gas E&P facilities. The oil the Group loads out is less volatile and is considered "dead" oil.

In addition, E&P facilities generally have controls (combustors) at their facilities and can route emissions from hydrocarbon liquid loadout back to the tanks. The Group's facilities do not have combustors and would be required to retrofit facilities to accommodate combustors. The benefit to control one or two oil loadouts a month is diminished because we are burning pilot gas 24/7 when it is not in use. Not only would the combustor burn pilot gas, but in the application to combust the higher moisture vapors, the vapor stream would need supplemental fuel to achieve complete combustion. It would be necessary to add VOCs (supplemental fuel) to the combustor and when burned we would also be increasing NOx and CO emissions. A letter discussing the need for supplemental fuel at Streams with High Moisture Content is attached as Attachment D. The proposed rule would force the Group to incur large capital expenses to retrofit combustors on our sites either on the tanks or specifically for hydrocarbon load out. The costs would include capital costs, non-recurring costs, and O&M costs. Many of these facilities will need to be retrofitted with new tanks and vapor lines in order to meet the requirements of the proposed rule. In total, the capital costs could be over $500,000 and the O&M costs of $40,000 per year. The calculated cost to control VOC in dollars per ton would be $28,657.85 per ton of VOC controlled. A detailed Cost Estimate of Economic Impacts of this section of proposed rules as applied to the Group's facilities is attached as Attachment E.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO REGULATING HYDROCARBON LIQUID TRANSFERS WHERE THE USE OF AIR POLLUTION CONTROL EQUIPMENT WOULD BE TECHNICALLY INFEASIBLE?

A: Yes. In order to avoid these unintended and harmful results, the Group proposes excluding from the requirements of Section 20.2.50.120 hydrocarbon liquid transfers with an uncontrolled

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PTE less than two tpy of VOC and a process for requesting an exemption from this requirement at sites with low hydrocarbon concentrations equal to or greater than two tpy. In general, the rules should promote common sense solutions rather than costly and technically infeasible ones.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A. Yes. I propose revisions to section A of 20.2.50.120 that will address my concerns. Hydrocarbon liquid transfers with an uncontrolled PTE less than two tpy of VOC would be excepted from the requirements. In addition, where air pollution control equipment can be demonstrated to be technically infeasible, including inability to operate without supplemental fuel, the owner or operator may apply to the NMED for an exemption from the control requirements of Section 20.2.50 NMAC.

Q: HAVE YOU PREPARED SPECIFIC REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: Yes. Our proposed revisions are shown in the redline below.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part. Owners or operators of hydrocarbon liquid transfers for which the use of air pollution control equipment would be technically infeasible, including but not limited to the fact that such equipment would not operate without supplemental fuel, may apply to the department for an exemption from the control requirements of Section 20.2.50 NMAC. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the hydrocarbon liquid loading monitoring requirements. Without limitation, evidence submitted by an applicant under this paragraph for an exemption based on technical infeasibility of a combustor demonstrating that emissions to be controlled from hydrocarbon liquid transfers are below the minimum BTUs specified by the manufacturer of the combustor to operate the combustor without the use of supplemental fuel, shall constitute technical infeasibility. All other applications will be considered on a case-by-case basis.

Q: DO YOU HAVE OTHER CONCERNS WITH 20.2.50.120 NMAC?

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A: Yes. Since many of the disposal well operations are unmanned, visual inspections required under subsection C(1) of 20.2.50.120 NMAC would be impossible to meet without substantial cost increases for these unmanned facilities. In addition, under subsection C(3) of 20.2.50.120 NMAC, the owner or operator of the facility will not be in a position to conduct annual testing of another company's tanker trucks and tanker rail cars.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO MONITORING REQUIREMENTS UNDER 20.2.50.120 NMAC?

A: Yes.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A: Yes. Instead, we request that for unmanned disposal well operations, NMED consider making the visual inspections a weekly requirement. In addition, we recommend requiring the owner or operator of the tanker trucks and tanker rail cars be the one responsible for ensuring annual testing is conducted.

Q: HAVE YOU PREPARED SPECIFIC REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: Yes. Our proposed revisions are shown in the redline below.

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. At unmanned locations, the owner or operator shall visually inspect the transfer equipment weekly to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

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

IV. STORAGE VESSELS

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.123 NMAC AS PROPOSED?

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A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH 20.2.50.123 NMAC.

A: Section 123 imposes emission control requirements in relation to storage vessels which are technically infeasible where the use of supplemental fuel is required and would contribute to an increase of total emissions. As written, facilities with very low emissions could end up increasing total emissions with use of supplemental fuel in order to combust vapors.

Generally, the produced water received by the Group has been processed by the producers prior to its receipt and is then typically further processed by the members of the Group. This water is therefore considered “post-flash” water that characteristically contains very low levels of VOCs. The proposed rule would compel emission reductions in some situations that are technically infeasible because compliance would require the use of supplemental fuel for combustion of vapors. In these situations, sites with very low hydrocarbon concentrations in the vapors could end up increasing total emissions of not only VOCs, but oxides of nitrogen (“NOx”) and carbon monoxide (“CO”) as well, due to the use of supplemental fuel for combustion. In order to avoid these unintended and harmful results, the Group proposes a process for requesting an exemption from this requirement in Section 20.2.50.120 when these circumstances are present. In addition, the requirement to control VOC emissions by at least 95% or 98% does not account for the possibility that some emissions may not be captured by the vapor return line or vapor collection system.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO REGULATING STORAGE VESSELS WHERE THE USE OF AIR POLLUTION CONTROL EQUIPMENT WOULD BE TECHNICALLY INFEASIBLE?

A: Yes. In order to avoid these unintended and harmful results, the Group proposes a process for requesting an exemption from this requirement in Section 20.2.50.123 at sites with very low hydrocarbon concentrations. In general, the rules should promote common sense solutions rather than costly and technically infeasible ones.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A. Yes. I propose revisions to sections A of 20.2.50.123 that will address my concerns. Where air pollution control equipment can be demonstrated to be technically infeasible, including inability to operate without supplemental fuel, the owner or operator may apply to the NMED for an exemption from the control requirements of Section 20.2.50 NMAC.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A: Yes.

Q: HAVE YOU PREPARED SPECIFIC REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: Yes. Our proposed revisions are shown in the redline below.

20.2.50.123 STORAGE VESSELS

A. Applicability:

Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC except as provided in [new] B(9) below.

(9) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible, including but not limited to the fact that such equipment would not operate without supplemental fuel, may apply to the Division for an exemption from the control requirements of Section 20.2.50 NMAC. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements. Without limitation, evidence submitted by an applicant under this paragraph for an exemption based on technical infeasibility of a combustor demonstrating that emissions to be controlled from a storage tank are below the minimum BTUs specified by the manufacturer of the combustor to operate the combustor without the use of supplemental fuel, shall constitute technical infeasibility. All other applications will be considered on a case-by-case basis. [Note: If B(8) regarding EMT is not stricken, this new subsection would be B(10).]

Q: ARE YOU AWARE OF OTHER STATES HAVE ADDRESSED YOUR CONCERNS REGARDING TECHNICAL INFEASIBILITY?

A. Yes. Colorado addressed this very issue in a 2019 Air Quality Control Commission ("Commission") rulemaking. In the rulemaking, the Commission determined that it did "not want to facilitate or encourage the use of supplemental fuel to operate control equipment" and understood

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this could be an issue "where the facilities have lower pressure." To address this problem, the Commission adopted a provision that allows operators to seek an exception to controlling tanks between 2 and 6 tpy VOCs. 5 CCR 1001-9, Statements of Basis, Specific Statutory Authority and Purpose, p. 302 (December 19, 2019). The Commission rule language states:

> Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

5 CCR 1001-9, Part D, II.C.1.c.(iii).

Q: DO YOU BELIEVE THE REASONING OF THE COLORADO AIR QUALITY CONTROL COMMISSION IS SOUND?

A: Yes. The Commission specifically looked at the operations of disposal well facilities and made a determination that there were circumstances where the use of air pollution equipment is technically infeasible, including instances where effective operation of combustion controls is not achievable without supplemental fuel. I believe this is a reasonable approach to concerns raised by the Group and request our proposed language be adopted.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

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SENIOR PROJECT MANAGER

Versatile, communicative and technically-astute Project Manager with demonstrated ability to successfully execute and implement projects through multiple challenging environments and situations. Conversant amongst all levels and departments of the organization. Strong background in implementing company-wide change initiatives from inception to final deliverable.

Key Skills:

- Project Management
- Budget Creation & Administration
- Client & Vendor Relations
- Proposal Development
- Consulting
- Root Cause Analysis
- Data Analysis
- Cross-Functional Teams
- Project Engineering
- Client & Contract Negotiations
- Cross-Departmental Communication
- Process Improvement
- Conflict Management
- Agency Negotiations
- Regulatory Management
- Presentation Skills
- Leadership
- Contract Management
- Database Creation & Implementation
- Change Management
- Public Speaking
- Research & Analysis
- Building Collaborative Relationships
- Problem Solving

Technical Skills:

- Colorado Environmental Regulations
- ND Environmental Regulations
- Wyoming Environmental Regulations
- Texas Environmental Regulations
- NM Environmental Regulations
- tt
- Emission Calculations
- Instrument Diagram Review
- Emission Estimation Tools
- ACTS/Intelex Software
- Environmental Compliance
- OGI Certification and Use
- Due Diligence
- SPCC
- Air Permit Engineering
- Permitting
- Efficiency Process Implementation
- Regulatory Reporting

EDUCATION

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Masters of Business Administration – Energy, 2022

Arizona State University, Tempe, Arizona
Bachelor of Science in Chemical Engineering, 2009

PROFESSIONAL EXPERIENCE

NGL Energy Partners LP, Denver, CO
Sr. Air Permitting Engineer February 2018 – Present
Recruited as the Lead Permitting Engineer and Project Manager for air-related permitting, regulatory, compliance, and pre-construction requirements for environmental projects. Led the initiative for creating new database and compliance tracking software.

- <u>Manage multiple projects</u> by drafting request for quotes and creating and monitoring project scope, schedule, and budget. Continual attention paid to contractor and team management, permitting, compliance, record keeping, and reporting while ensuring project completeness standards are met.

Attachment A

- Lead air quality/permitting projects with the goal of achieving 100% compliance and zero violations by analyzing, modifying, and recommending facility design changes to meet local, state, and/or federal requirements. Permitting new facilities in the states of Colorado, New Mexico, Texas, and Wyoming.
- Liaise with regulatory agencies for policy development including Colorado TENORM and Wyoming DEQ pond emissions tool making certain new policies have minimal impact on NGL's ability to adapt and operate effectively.
- Serve as primary point of contact and technical expert for local, state, and federal agencies in Colorado, New Mexico, Texas, and Wyoming, safeguarding against violations as well as handling the logistical demands of facility audits.
- Air technical expert on rule makings in Colorado, New Mexico, and Wyoming. Serves as the technical expert on air realated issues and issues related to operations. Reducing the impact of rules on operations.

Terracon Consultants, Inc., Wheat Ridge, CO
Senior Staff Engineer February 2017 – February 2018
Senior Project Manager for all current and new oil and gas (O&G), air and other air-related projects. Managed field team coordination and project execution for inspection and leak detection work, including but not limited to permitting, budgeting, staffing, quality assurance, resources and regulatory review to see the project successfully from cradle to grave.

- Led projects for acquiring O&G well pads. Performed due diligence for initial acquisition as well as created regulatory break down for federal and state regulations pertaining to air emissions.
- Executed business development efforts focusing on air-related projects and air permitting work landing two major contracts for O&G clients and one large remediation project for MillerCoors bottling plant.
- Developed novel approaches to Spill Prevention, Control, Countermeasure and SWPPP plans for O&G exploration, production sites and other industrial sites in Texas, Utah, and Colorado.
- Implemented greenhouse gas calculations (GHG) per United State Environmental Protection Agency's regulations.
- Performed permitting functions including permit updates, permit and site audits, terminal and load out permits, well pad permits, other industry permits, best available control technology analysis and reasonably available control technology analysis in Wyoming, Colorado, Utah, North Dakota, New Mexico, Oklahoma, and Texas.
- Managed permitting and compliance program for three Exploration and Production (E&P) operators for over 100 sites.

Eagle Environmental Consulting, Inc., Denver, CO
Project Engineer June 2016 – February 2017
Lead air quality technical advisor for oil and gas operators. Managed air quality compliance utilizing skills in permitting, data collection, greenhouse gas calculations, optical gas imaging, consent decree management, state and federal permitting, regulatory determination, and compliance.

- Developed top-notch air program and schedule of best practices for optical gas imaging program delineating regulatory breakdown and review of state and federal regulations in North Dakota for upstream O&G. Program and best practices are still in use today and considered the standard for detecting leaks and maintaining compliance.
- Guided the procurement of over 50 oil and gas wells and well pads for clients by carrying out contract negotiations, facility acquisition assistance, and due diligence in thorough detail to ensure sites acquired are in compliance with local, state, and federal environmental regulations.
- Managed, analyzed and remediated over twenty soil and ground water projects for retail gas stations and O&G clients. Oversaw scope, schedule, and budget. Conducted quarterly monitoring events and negotiated remediation options with state representatives.

Astrodyne International, Inc., Denver, CO
Sales Representative September 2015 – June 2016
Established and successfully maintained client accounts by creating new ways to source clients, building rapport, nurturing strong relationships and providing excellent customer service.

- Onboarded two airlines and garnered lead provider status for a parts broker. Uniquely sourced potential customers by analyzing market through a gamut of data searches matching customer needs with company services and benefits.
- Developed government profile for small business contracting, overcoming numerous obstacles and securing a relationship for federal and state contracts.
- Performed needs and benefit analysis for clients, prepared quotes for service and presented to clients using a consultative approach, overcoming objections, closing the sale and following through with client.
- Represented Astrodyne by serving as main point of contact with government entities on repair contracting.

Anadarko Petroleum Corporation, Denver, CO
Environmental Health & Safety (EHS) Representative II, June 2014 – May 2015
Recruited to manage permits for one of the world's largest independent production companies. Managed monitoring and implementation for Colorado Regulation 7. Activities center around but not limited to permitting, data validation, data collection, field verification, scheduling, and compliance.

- Collaborated on a team to develop the first Colorado Regulation 7 Storage Tank Emissions Monitoring Program. Developed plan and protocol which tied in seamlessly with Operations, Accounting, and Environmental Health & Safety (EHS).
- Implemented and conducted audits on the leak detection and repair program regulations using cutting edge technology developed at previous position (Trihydro) to ensure compliance with state air standards using optical gas imaging.
- Created protocols and procedures for Operations and Inspection teams.
- Co-created and trained over 250 field personnel across multiple days to implement data collection program and Colorado Regulation 7 program to comply with state and federal regulation.
- Co-built new reporting system for large sets of historical and current O&G production facility data to detail emissions, tracking, and construction/ asset management.

Trihydro Corporation, Laramie, WY
Chemical Engineer Jan. 2011 – June 2014
Hired as Chemical Engineer for permitting and air compliance. Developed into Project Manager for all Green House Gas (GHG) projects. Lead technical advisor and greenhouse gas manager for optical gas imaging and compressor vent monitoring. Managed a team of six field and floater personnel for contracting projects with budgets of $300,000.

- Conducted environmental compliance monitoring at oil and gas facilities including creating project scope, schedules, and budgets and managing all logistics including client relations, financial and human resources, invoicing and monitoring scope, and budget creep.
- Co-developed a procedure and apparatus for the measurement of gas flow rates. Created best practices for every optical gas imaging project at Trihydro as well as other O&G companies to ensure correct equipment operation and instrument check procedures.
- Co-created the Green House Gas (GHG) Program from scratch for EPA's new reporting standards. Designed and presented training programs on Optical Gas Imaging, Air Regulations, compressor vent monitoring, and Colorado Regulation 7.
- Reviewed process and instrument diagrams for regulatory applicability at petroleum refineries, petrochemical facilities, and natural gas processing facilities.
- Conducted hundreds gas imaging surveys and compressor vent flow rate measurement field events and prepared associated technical reports to be reviewed by clients and EPA.
- Collected large sets of data--thousands of data elements-- and calculated greenhouse gas emissions for federal air regulations.
- Submitted air quality permit applications across five states for various O&G clients (i.e., Texas, North Dakota, Wyoming, Colorado, and Utah).

H2X Environmental Consulting

Chemical Engineering Consultant April 2010 – Dec. 2010

- Managed, coordinated and reported on water monitoring and coal bed methane water discharges for clients and the Wyoming Department of Environmental Quality (DEQ).
- Surveyed reservoir depth in order to calculate water discharge and report to DEQ and clients.

PROFESSIONAL ASSOCIATIONS

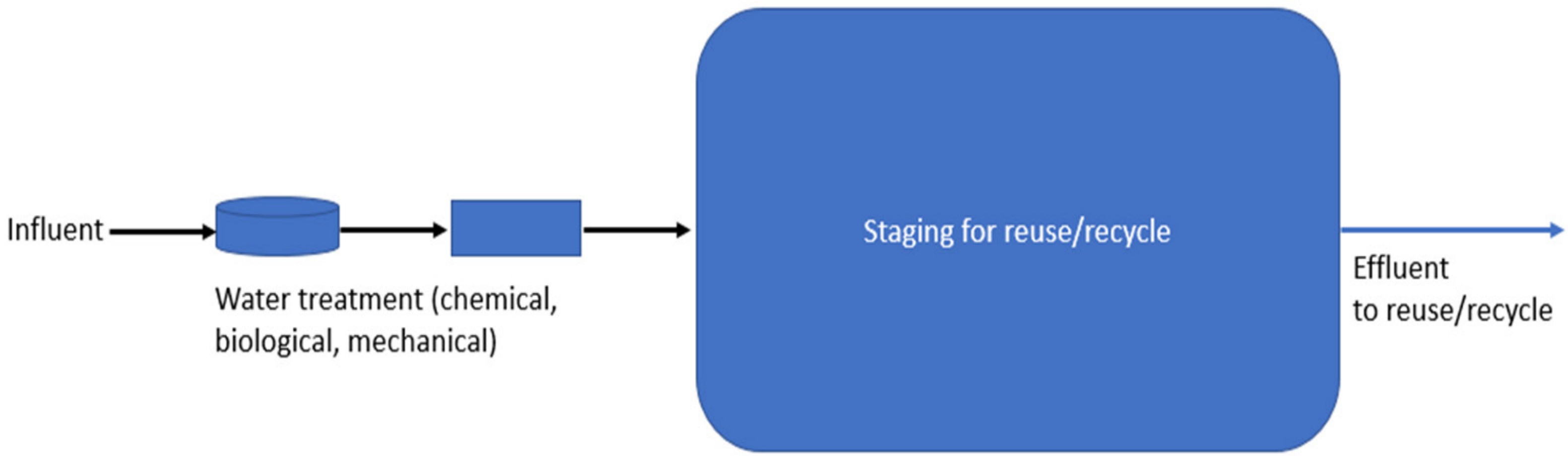
Member of American Institute of Chemical Engineers (AICHE) – 7 years

ADDITIONAL RELEVANT SKILLS, EXPERENCE AND REGULATORY KNOWLEDGE

Trainings:
Safeland USA, CPR / First Aid / AED, 40-hour OSHA HAZWOPER

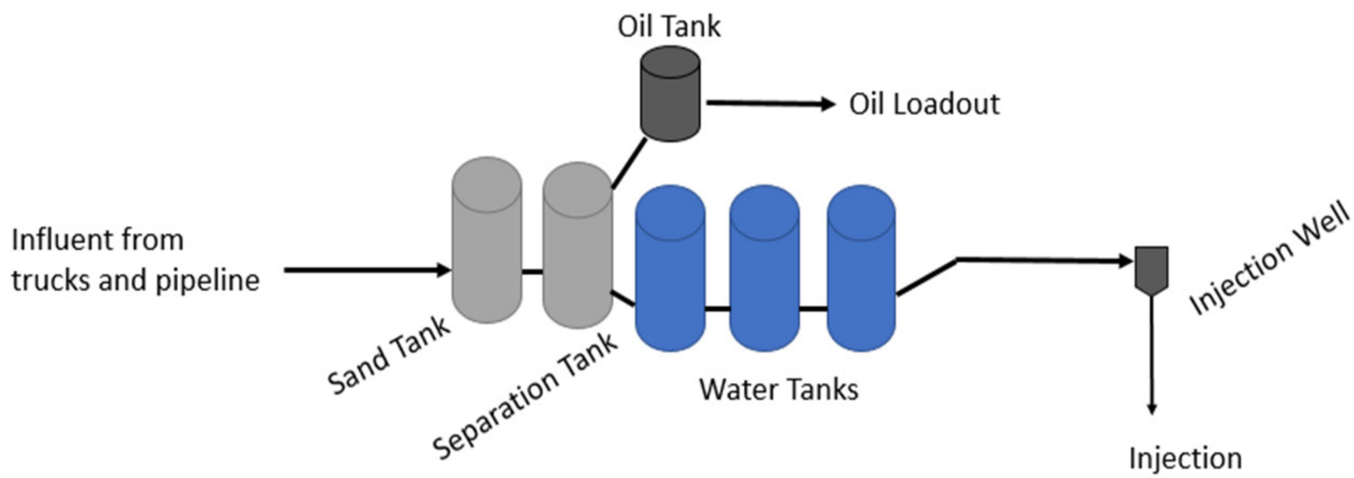
Regulatory Competencies:
State air permitting requirements (CO, ND, NM, TX, WY), Title V Compliance and Permitting, Colorado Regulation 7, EPA 40 CFR Part 98, EPA 40 CFR Part 60

Typical Produced Water Management Unit Design



Attachment B

Typical Disposal Well Operation



Attachment C

To:

IL KIM
NGL Energy Partners

Date: 7/27/2021

When flaring streams with the potential to have high moisture content and with a Lower Heating Value (LHV) ≤ 1200 BTU/scf, if the streams are sent to an enclosed natural draft combustor we recommend that the customer include an additional connection for injection of assist gas.

The recommended (ideal) operating temperature for our natural draft enclosed combustors is approximately 1800 F. The purpose of the assist gas is to offset the amount of heat removed by the moisture (latent heat of evaporation) and ensure that the temperature in the combustion chamber does not drop below 1600 F.

For streams with high moisture content we also recommend to apply rigidizer paint to protect the ceramic fiber insulation of the combustion chamber.

Please do not hesitate to contact the undersigned should you have any further questions,

Best Regards

Giorgio Sibilia
Cimarron | Combustion Products

(Cell) 512-247-1557
gsibilia@cimarron.com

ATTACHMENT D

*These costs are preliminary estimates that are subject to change based on further engineering analysis and further communication with vendors.

Cost to Control Tank Emissions:

	Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Included in EIA	48" Cimmeron Combustor HV ECD 12MMBTU/hr	$ 28,000.00				Estimate provided by manufacturer. Includes freight, platform and installation. This estimate does not include the cost of a blower which would likely be required due to the low pressures throughout the system. In the short timeframe, we were not able to obtain a cost estimate from a vendor.
	Engineering		$ 7,500.00			50 hours @ 50/hour for engineer labor.
	Flare Install		Included above			Using value provided by CDPHE in the 2020 EIA
	Auto-igniter	$ 1,817.00				Using value provided by CDPHE in the 2020 EIA
	Pilot fuel			$ 9,619.04		25 scf/hr * 0.0278 gallons/scf = 0.695 gal/hr; 0.695 gal/hr *24 hr/day = 16.68 gal/day; 16.68 gal/day * 365 days/year = 6088.2 gal/year; (6088 gal/year) / (400 gal/tank) = 15.22 fills per year). prices fluctuate in the year between 1.20 and 1.60 a gallon . a 500 gallon tank of propane holds 400 gallons of propane 1 fill is $550 average. (6088 gal/year* $1.58/gal = $9619.04)
	Flare maintenance			$ 30,127.74		Flare and associated piping maintenance. Labor is estimated at 0.5 hours per 8-hour shift. Maintenance materials costs are assumed to equal maintenance labor costs.
Additional Costs	Propane transportation			$ 1,620.00		As the Division states in the Initial EIA, "[c]lass II disposal well facilities without a supply of well gas need to supplement with propane or other gaseous fuel to maintain the flare pilot light and assist in combusting the loadout vapors, which adds to the expense of the control device operation. The Division does not have information on the cost of transporting fuel to assist the flare or the number of sites without onsite well gas. Therefore, the Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions." Estimate 10 dollars a month for a wireless gauge service that alerts the company of when tanks need filled. ($10/month auto gage * 12 months = $120) + ($100 delivery fee * 15 = 1500) = $1620/ year
	Power Extension		$ 10,000.00			This is an estimate to re-route power to the auto-igniter, assuming power is already on location.
	Pipe, parts & fittings, vapor manifolding lines together and routing to combustion device		$ 30,000.00			Piping required due to storage tanks not being connected via vapor manifold. Operators would also need to install supports on the tanks and piping. This includes labor and material and would be a multiple day project. Typically there are 10-20 process tanks and approximately 5 recovered oil storage tanks at commercial class II disposal well facilities.
	Tank Upgrades	$ 510,840.00				Assumes replacement of 20 fiberglass tanks per site. 750 bbl tanks.
	Knock out pot	$ 20,000.00				A specific type of knock-out pot is required to pull off water laden vapor. This also includes return line otherwise it will bog down the system.
	Installation of propane tank and barrier	$ 1,500.00	$ 1,000.00			Estimate from vendor includes materials, formed, and poured. 1500 for the tank not including pouring the pad, and then an additional $1000 to pour concrete pad.
	Subtotal	**$ 562,157.00**	**$ 48,500.00**	**$ 41,366.78**		
	Annualized Cost	**$ 77,912.27**	**$ 3,233.33**	**$ 41,366.78**	**$ 122,512.38**	

Class II disposal well facilities are unable to accurately evaluate emission reduction per $1, as the industry does not expect that it could meet the destruction efficiency of 95% due to the vapor composition.

Tank uncontrolled Actual VOC Emissions	Annualized Cost	Emission Reduction	VOC Cost control ($/ton)
>2 ≤ 3 tpy	$ 122,512.38	$ 2.38	$ 51,584.16
>3 ≤ 4 tpy	$ 122,512.38	$ 3.33	$ 36,845.83
>4 ≤ 5 tpy	$ 122,512.38	$ 4.28	$ 28,657.87

This is assuming combustion would be 95%, but as discussed in the JIWG PHS, it is unlikely the control device would achieve the destruction efficiency of 95% due to vapor composition.

Attachment E

This cost estimate includes the costs of AIMM, AVO, and associated recordkeeping as this is the first time class II disposal well facilities would be required to implement those programs.

As the Division states in its Initial EIA, "[t]here will be costs related to data collection and associated recordkeeping and reporting requirements. **The Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions.**"

AIMM (either Contractor AIMM *or* in-house AIMM)
Contractor AIMM

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Semi-annual Inspection			$ 1,952.97		Estimate provided by consultant
Repair Confirmation			$ 1,559.50		Estimate provided by consultant
Recordkeeping / Data Management			$ 752.00		Estimate provided by consultant
Subtotal	**$ -**	**$ -**	**$ 4,264.47**		
Annualized Cost	**$ -**	**$ -**	**$ 4,264.47**	**$ 4,264.47**	

OR

In-House AIMM

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
FLIR Camera	$ 122,000.00				Modeled after prior Division EIA
FLIR Camera Maint/Repair:			$ 7,500.00		
Photo Ionization Detector	$5,000				
Vehicle (4x4)	$ 22,000.00				
Inspection Staff			$ 75,000.00		
Supervision (@20%)			$ 15,000.00		
Overhead (@10%):			$ 7,500		
Travel(@15%):			$ 11,250		
Recordkeeping (@10%):			$ 7,500		
Reporting (@10%):			$ 7,500		
Fringe (@30%):			$ 22,500		
Subtotal	**$ 149,000.00**	**$ -**	**$ 153,750.00**		
Annualized Cost	**$ 39,879.12**	**$ -**	**$ 153,750.00**	**$ 193,629.12**	

Emission reduction unknown.

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Emissions Inventory Recordkeeping & Reporting					
Record Keeping set-up, inventory specs		$ 2,064.00			Estimate provided by consultant
Monthly Emissions Inventory Records			$ 1,128.00		Estimate provided by consultant
Annual Report			$ 317.00		Estimate provided by consultant
Supervision (@15%)		$ 309.60	$ 216.75		Estimate provided by consultant
Weekly AVO Inspections					
Average per facility		$ 451.00	$ 23,452.00		Estimate provided by consultant
Cost of Supplemental Off-ramp Analysis					
Average per facility:		$ 1,318.47			Estimate provided by consultant
EF Development		$ 516.00			Estimate provided by consultant
Additional APEN preparation		$ 564.00			Estimate provided by consultant
APEN Submittal		$ 216.00			Submittal fee
Subtotal	**$ -**	**$ 5,439.07**	**$ 25,113.75**		
Annualized Cost	**$ -**	**$ 5,439.07**	**$ 25,113.75**	**$ 30,552.82**	

Emission reduction unknown.

Cost to Control Loadout

	Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Included in EIA	48" Cimmeron Combustor HV ECD 12MMBTU/hr	$ 28,000.00				Estimate provided by manufacturer. Includes freight, platform and installation. This estimate does not include the cost of a blower which would likely be required due to the low pressures throughout the system. In the short timeframe, we were not able to obtain a cost estimate from a vendor.
Included in EIA	Engineering		$ 7,500.00			50 hours @ 150/hour for engineer labor
Included in EIA	Auto-igniter	$ 1,817.00				Using value provided by CDPHE in the 2020 EIA
Included in EIA	Pilot fuel			$ 9,619.04		25 scf/hr * 0.0278 gallons/scf = 0.695 gal/hr; 0.695 gal/hr *24 hr/day = 16.68 gal/day; 16.68 gal/day * 365 days/year = 6088.2 gal/year; (6088 gal/year) / (400 gal/tank) = 15.22 fills per year). prices fluctuate in the year between 1.20 and 1.60 a gallon . a 500 gallon tank of propane holds 400 gallons of propane 1 fill is $550 average. (6088 gal/year* $1.58/gal = $9619.04/year)
Included in EIA	Flare maintenance			$ 30,127.74		Flare and associated piping maintenance. Labor is estimated at 0.5 hours per 8-hour shift. Maintenance materials costs are assumed to equal maintenance labor costs.
Additional Costs	Propane transportation			$ 1,620.00		As the Division states in the Initial EIA, "[c]lass II disposal well facilities without a supply of well gas need to supplement with propane or other gaseous fuel to maintain the flare pilot light and assist in combusting the loadout vapors, which adds to the expense of the control device operation. The Division does not have information on the cost of transporting fuel to assist the flare or the number of sites without onsite well gas. Therefore, the Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions." Estimate 10 dollars a month for a wireless gauge service that alerts the company of when tanks need filled. ($10/month auto gage * 12 months = $120) + ($100 delivery fee * 15 = 1500) = $1620/ year
Additional Costs	Power Extension		$ 10,000.00			This is an estimate to re-route power to the auto-igniter, assuming power is already on location.
Additional Costs	Pipe, parts & fittings, vapor lines		$ 11,000.00			Installation of vapor lines.
Additional Costs	Installation of propane tank and barrier	$ 1,500.00	$ 1,000.00			Quote from vendor includes materials, formed, and poured. 1500 for the tank not including pouring the pad, and then an additional $1000 to pour concrete pad.
	Subtotal	**$ 31,317.00**	**$ 29,500.00**	**$ 41,366.78**		
	Annualized Cost	**$ 4,340.39**	**$ 1,966.67**	**$ 41,366.78**	**$ 47,673.84**	

Tank uncontrolled Actual VOC Emissions	Annualized Cost	Emission Reduction	VOC Cost control ($/ton)
>2 ≤ 3 tpy	$ 47,673.84	$ 2.38	$ 20,073.19
>3 ≤ 4 tpy	$ 47,673.84	$ 3.33	$ 14,338.00
>4 ≤ 5 tpy	$ 47,673.84	$ 4.28	$ 11,151.77

This is assuming combustion would be 95%, but as discussed in the JIWG PHS, it is unlikely the control device would achieve the destruction efficiency of 95% due to vapor composition.

APPENDIX B

DIRECT TESIMONY OF ASHLEY CAMPSIE

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

TESTIMONY OF ASHLEY CAMPSIE

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A: Ashley Campsie. 261 Columbine Ln, Evergreen, Colorado 80439.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am President of Evergreen Environmental Engineering, Inc. In addition to performing the duties of company President, I also work as an environmental engineer for the company.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of NGL Energy Partners LP ("NGL"), Solaris Water Midstream, LLC ("Solaris"), Oilfield Water Logistics SWD Operating, LLC ("OWL"), Goodnight Midstream, LLC ("Goodnight"), and 3 Bear Energy, LLC ("3 Bear"), which I may collectively refer to as the "Commercial Disposal Group" or the "Group."

Q: PLEASE STATE BRIEFLY THE NATURE OF THESE BUSINESSES.

A: As relevant to the New Mexico Environment Department's ("NMED") proposed ozone precursor rules, each company has commercial operations in New Mexico for the recycling and/or underground injection of produced water.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the Group's concerns with certain provisions in NMED's proposed ozone precursor rules that would negatively impact their businesses, water conservation efforts, and the broader environment, and to propose common sense alternatives that will satisfy the purpose of the proposed rules.

Q: DOES YOUR EDUCATION AND EXPERIENCE QUALIFY YOU TO TESTIFY ON THIS TOPIC?

A: Yes. I have attached my CV as Appendix A, which describes my qualifications in detail. In summary, I have a degree in engineering and have worked in the field of environmental engineering for over twenty-five years, a majority of which has been focused on developing a specialty in air quality permitting and compliance for the oil and gas industry.

Q: DO YOU OPPOSE NMED'S PROPOSED OZONE PRECURSOR RULES?

A: I oppose certain provisions in NMED's proposed ozone precursor rules, which I will explain in my testimony. Specifically, I will address the proposed rules relating to (i) engines and turbines, (ii) produced water management units ("PWMU"), and (iii) transfer of ownership compliance evaluation.

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH THE PROPOSED OZONE PRECURSOR RULES.

A: The provisions I am concerned with appear to be crafted to address NMED's concerns at sites owned and operated by oil and gas producers. However, in many instances, the language is not a good fit as applied to operations at commercial produced water disposal facilities. When applied to these types of facilities, the provisions would impose requirements that are unduly onerous and/or technically infeasible and would likely return little environmental benefit.

II. ENGINES AND TURBINES (20.2.50.113 NMAC)

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.113 NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: Section 20.2.50.113 requires operators to test engines every year. This is not consistent with current federal regulations and would pose unnecessary confusion between conflicting regulations.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO TESTING ENGINES?

A: Yes. The rule language should be changed to mirror the federal requirements under 40 CFR Part 60, Subpart JJJJ ("NSPS JJJJ").

Q: HAVE YOU PREPARED SPECIFIC REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: Yes. Our proposed revisions are shown in the redline below.

20.2.50.113 ENGINES AND TURBINES:

….B….(~~10~~9) The owner or operator of an emergency use engine that is operated less than 100 hours per year for non-emergency situations, 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...

C. (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 shall be demonstrated by performing an initial emissions test, followed by subsequent ~~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:...

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

(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 or 3 years of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per Year for non-emergency situations, shall monitor the hours of operation by a non-resettable hour meter.

Q: CAN YOU WALK US THROUGH THE REDLINE?

A: Yes. Section 20.2.50.1113, addresses among other items, requirements for emergency use engines and testing requirements. To be consistent with NSPS JJJJ, the 100 hrs per year has been clarified to include non-emergency hours. In addition, the testing frequency has been changed to align with NSPS JJJJ to require testing every 8760 hours or 3 years, which ever comes first.

III. <u>PRODUCED WATER MANAGEMENT UNITS (20.2.50.126 NMAC)</u>

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.126.B NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: Section 20.2.50.126.B requires operators to control VOC emissions from each produced water management unit ("PWMU") to less than two tons per year. This emissions cap is unreasonable and will likely not be met by most PWMU operations. As a result, it will likely have the effect of eliminating recycle ponds from New Mexico and driving recycling operations out of state.

Q: WHY CAN'T THE TWO TONS PER YEAR EMISSIONS CAP BE MET?

A: PWMUs are large in size and their emissions are fugitive in nature. This makes it very difficult to estimate or measure PWMU emissions. In fact, there is no federally specified or state consensus on a method for estimating or measuring emissions from open ponds. Even though the hydrocarbon content of brine water within a PWMU is low, the large volume of water can result in VOC emissions above two tons per year. The large size and fugitive nature of pond emissions also makes it difficult to control emissions through traditional control devices or control mechanisms. This combination of factors renders the two tons per year VOC emission limit unreasonable to satisfy.

Q: IS THIS WHY YOU CONCLUDED THAT THE TWO TONS PER YEAR VOC EMISSIONS CAP WILL RESULT IN ELIMINATING RECYCLING OPERATIONS FROM NEW MEXICO?

A: Yes, the two tons per year emissions cap will make it too difficult to operate water recycling and reuse ponds, so they will have to be shut down in New Mexico, stymieing water conservation efforts put in place two years ago by the New Mexico legislature. In 2019, the legislature passed H.B. 546, the Produced Water Act, with the intention of bolstering use of recycled produced water for oil and gas operations, in lieu of fresh water resources. The Act implemented various policy measures, all aimed at facilitating, through regulatory clarity and on the ground policy adjustments, a robust shift from reliance on fresh water for hydraulic fracturing to recycled produced water. Notably, the Act passed the New Mexico House of Representatives with unanimous support and the Senate with near unanimous support, garnering praise from House Speaker Brian Egolf as one of the "greatest environmental accomplishments" to come out of the legislature. And, the Act has succeeded, as the industry has turned in bulk from fresh water to recycled produced water to support operations. The New Mexico Oil Conservation Division reports that, since October 2020, 408 wells have been completed at an average of 377,290 barrels of water, and that 55% of that water is recycled produced water, or eighty-five million barrels of water. Because water recycling is a more sustainable practice than use of fresh water, it should and will continue to become the industry standard. However, the rule as presently written, has the undesired effect of driving this recycle activity out of New Mexico. The draft rule appears to accept as a narrative that a choice must be made between capturing ozone precursor molecules and facilitating continued investment in produced water recycle. The draft rule answers that false choice by likely closing the door on continued investment in produced water recycle in the State in favor of capturing some unknown quantity of additional precursors. This outcome is avoidable.

Q: PLEASE EXPLAIN FURTHER YOUR TESTIMONY THAT EMISSIONS FROM PWMUS IS FUGITIVE?

A: Fugitive emissions are emissions that could not reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Emissions from open ponds cannot reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Attempts have been made in the past to cover recycling ponds as well as feed lot ponds in order to capture or minimize vapors for both emission and odor purposes. These attempts have failed for the following reasons: i) safety for workers; ii) technical feasibility; iii) compromising the liners for soil and groundwater protection; iv) economics; and v) general maintenance issues.

Q: PLEASE EXPLAIN FURTHER WHY IT IS DIFFICULT TO CONTROL EMISSIONS FROM PWMUS.

A: As already discussed, covering these ponds is not reasonable and therefore makes capturing the vapors to send to a combustor or carbon filter extremely difficult. Best management practices through the reduction of hydrocarbons in the water prior to entering the pond is a more successful and practiced approach to minimizing emissions from the ponds.

Q: DO YOU HAVE OTHER CONCERNS WITH 20.2.50.126.B?

A: Yes. The use of an emissions cap is an unusual and inappropriate mechanism for regulating PWMUs. Rather than prohibiting activities or emission sources that exceed an emissions cap, air regulations typically impose performance standards, best practices, or require controls. There are many regulated emission sources that exceed two tons per year of VOC emissions and are not prohibited through the use of an emissions cap. For example, the glycol dehydrator, pigging and receiving and storage vessels rules proposed in this rulemaking establish capture and or control requirements triggered at two or one tons per year VOC emissions. Most Federal New Source Performance Standard emission sources that exceed a threshold are required to meet specific performance standards rather than a maximum emission limit such as NSPS Subparts OOOO and OOOOa and MACT Subpart HH. PWMUs should be similarly regulated through performance standards.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO REGULATING PWMUS?

A: Yes. In general, the rules should promote rather than prohibit the use of PWMUs for water recycling operations.

Q: WHY IS THAT?

A: As discussed in more detail by Mr. Kim, the members of the Commercial Disposal Group operate PWMUs at which millions of barrels of brine water are recycled each year and returned to oil and gas producers for use in hydraulic fracturing operations. This recycling helps oil and gas producers in New Mexico conserve the State's important freshwater resources.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A: Yes. I propose revisions to sections A through D of 20.2.50.126 that will address my concerns. First, the existing provisions for best management practices, good engineering practices, monitoring, recordkeeping, and reporting would apply in all cases. Second, for PWMUs with emissions greater than 25 tons per year of VOC fugitive emissions, the operator would be required to obtain a permit from NMED unless it is a recycling operation registered with the Oil Conservation Division. Such sources would not be subject to 20.2.50 NMAC. The permit would be facility-wide, include point sources located onsite, and consider PWMUs as fugitive emission sources. The fugitive emissions would not count toward the VOC limit in the permit.

Q: HAVE YOU PREPARED SPECIFIC REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: Yes. Our proposed revisions are shown in the redline below.

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. Except that a facility which includes a produced water management unit equal to or greater than 25 tons per year of VOC emissions shall obtain a permit from the Department and is not subject to 20.2.50 NMAC. Sources located at a facility or containment that are permitted or registered with the State of New Mexico, Oil Conservation Division as a recycling facility or containment are not subject to 20.2.50 NMAC.

B. Emission standards:

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

(2) The owner or operator shall either:

(a) control VOC emissions from each produced water management unit to less than 2 tons per year; or

(b) obtain a no permit required determination, file a notice of intent, or obtain a permit from the department.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the ~~monthly rolling 12-month~~ total of actual VOC emissions in tons from each unit on an annual basis;

(2) ~~monthly~~annually, ~~monitor~~ record the best management and engineering practices implemented ~~to reduce emissions~~ at each unit to ~~ensure~~ demonstrate their effectiveness.

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

D. Recordkeeping requirements:

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

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize emissions of VOC at the unit; and

(c) an annual record of the best management and engineering practices implemented at each unit to demonstrate the effectiveness ~~record of the monthly rolling 12-month 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.

Q: CAN YOU WALK US THROUGH THE REDLINE, BEGINNING WITH SECTION 20.2.50.126.A?

A: Yes. Section 20.2.50.126.A, addresses the scope of applicability I just described. It exempts from the rule facilities with PWMUs with VOC emissions greater than 25 tons per year but requires them to obtain a permit from NMED. The proposed revisions also exempt from the rule sources located at a facility or containment that are permitted or registered with the State of New Mexico, Oil and Conservation Division as a recycling facility or containment. These sources have to meet strict ppm limits for reuse and therefore would already have significant separation and treatment in place prior to entering a PWMU.

Q: PLEASE EXPLAIN YOUR REVISIONS TO SECTION 20.2.50.126.B.

A: Section 20.2.50.126.B, addresses the option to control to below two tpy or obtain a no permit required determination, file a notice of intent, or obtain a permit. This allows continued operation of ponds that can’t meet the two tpy threshold but still having a mechanism to pull these sites into the permitting program. It also will continue to keep produced water recycling to more likely be an economic option for operators to use during completions. This is more typical of clean air regulatory programs, where companies have the opportunity to implement appropriate practices to reduce emissions; instead of a hard limit where operations are not allowed.

Q: PLEASE EXPLAIN YOUR REVISIONS TO SECTION 20.2.50.126.C.

A: Section 20.2.50.126.C, reduces the burden on the regulated entity to annual requirements rather than monthly or rolling 12 totals as well as remove the requirements to follow the burdensome general monitoring requirements. Monthly and rolling 12 total requirements are generally reserved for synthetic minor sources as a means for practicable enforceability. Since best management practices are not add on control devices, PWMUs will likely be minor sources of emissions. Annual tracking should be sufficient for any compliance or emission inventory purposes.

Q: PLEASE EXPLAIN YOUR REVISIONS TO SECTION 20.2.50.126.D.

A: Section 20.2.50.126.D, aligns the recordkeeping with the changes to Section 20.2.50.126C for monitoring.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

APPENDIX A

CURRICULUM VITAE OF ASHLEY CAMPSIE

Ashley Campsie, PE
Senior Environmental Engineer

Compelling qualifications:

- ✓ Extensive experience in air quality permitting and compliance for the oil and gas industry working for both the State and industry.
- ✓ Specialist in state and federal air regulations as well as climate change and GHG management.
- ✓ Experience in auditing under self-audit and due diligence projects.
- ✓ Experience in development of GHG emission inventories and management plans for the oil and gas industry.
- ✓ Project Manager for numerous air permitting and compliance projects for the oil and gas industry.
- ✓ Commissioner on the Colorado Air Quality Control Commission from April 2007 through February 2014.

Education:

BS, Chemical Engineering, University of Colorado - Boulder

Years of Experience:

25

Ashley Campsie has over 25 years of experience in the public and private Environmental sectors. With a majority of her experience in the oil and gas arena, Ashley is recognized as a specialist in air quality permitting and compliance for the oil and gas industry. Examples of project experience include:

Since Starting Evergreen Environmental Engineering, Inc.

Technical Lead, Confidential Oil and Gas Exploration and Production Company, Colorado. Ms. Campsie provided assistance through legal counsel to evaluate and respond to agency enforcement actions for potential air quality permitting and compliance violations. Activities included developing a sampling program to determine site specific and area wide emission factors for crude and condensate tanks in both the attainment and non-attainment areas of Weld and Adams Counties and drafting the results in a final report. The final report was submitted to the agency and the enforcement actions were closed out.

Project Manager, Confidential Oil and Gas Exploration and Production Company. Ms. Campsie is providing air quality support for this small E&P company. Many of the projects involved reviewing applicable state and federal regulations for their operations in New Mexico and Wyoming. Activities included drafting permit applications and registrations, tracking changes and associated updates and emission inventories.

Project Manager, Bill Barrett Corporation. Ms. Campsie managed and provided assistance to BBC for various air permitting and compliance projects in Colorado and Utah (both state and tribal land). Projects involved reviewing potential applicability and compliance with state and federal air regulations pertaining to upstream and midstream oil and gas operations. State air permitting and Tribal NSR registrations including development of area wide emission factors for crude and condensate tank emissions have been conducted for well sites in the Uintah Basin.

Project Manager, Confidential Oil and Gas Exploration and Production Company, Colorado. Ms. Campsie is providing air quality expertise for operations in Utah, Wyoming and Colorado for this small oil and gas exploration and production company. Activities include calculation of potential and actual emissions, drafting permit applications, providing guidance on NSPS and MACT regulations, maintaining rolling 12 emission and production tracking and other compliance activities related to state and federal requirements.

While at CH2M HILL

Senior Technologist, Confidential Energy Company, LLC, Texas. Ms. Campsie served as the senior lead for the prevention of significant deterioration (PSD) major source greenhouse gas permitting effort for two compressed air energy storage (CAES) facilities. The effort involved estimating greenhouse gas emissions, preparing Best Available Control Technology evaluations, and preparing the application for EPA review.

Air Permitting Lead, East Cheyenne Gas Storage, LLC, Colorado. Ms. Campsie was the Air Permitting Lead for a FERC regulated proposed gas storage facility with enhanced oil recovery (EOR) activities. Responsibilities included providing support for the air sections of the FERC Resource Reports and Environmental Assessment. In addition, Ashley coordinated and provided senior support for the minor new source review permit and land disturbance permit applications.

Senior Technologist, GHG Management Plan and Information Management Solution Implementation (Enviance), Koch Minerals; As a Senior Technical Consultant, provided subject matter expertise in the development of a corporate-wide Inventory Management Plan enabled by an information management system powered by Enviance. Worked closely with the client and software implementation team to translate requirements for GHG emissions calculations to support the EPA Mandatory Reporting Rule report, other regulatory reports, and corporate reports. Worked with Enviance to review their GHG Pre-Configured Assets.

Senior Technologist, GHG Management Plan and Information Management Solution Implementation (Enviance), Dominion; As a subject matter expert for GHG emissions from gas operations, provided technical guidance to the client and project team in the development of a corporate-wide Inventory Management Plan (IMP) for Dominion's corporate and project inventories. The IMP was enabled by an information management system (Enviance). Worked closely with the client and software implementation team to translate requirements for GHG emissions calculations to support the MRR report, other regulatory reports, and corporate reports.

Project Manager, Confidential Oil and Gas Exploration and Production Company, Colorado. Ms. Campsie managed and provided subject matter expertise for the development of auditing protocols. The protocols covered federal and state regulations that apply to the upstream and midstream oil and gas sectors. The protocols were designed to assist the client with internal audits in Colorado, Louisiana, Pennsylvania, Texas, and Wyoming.

Project Manager, Confidential Large Midstream Oil and Gas Company. Ms. Campsie has managed over 17 projects for this confidential client ranging from air compliance to permitting for facilities in Wyoming and Colorado. Among some of the compliance projects were annual emission inventories, analysis of portable stack testing data, self-certification packages for Final Approval air permits, and annual and semi-annual Title V monitoring and compliance reports. Permit activities included minor source permitting, synthetic minor source permitting for PSD and synthetic minor source permitting for existing major sources in an ozone non-attainment area.

Project Manager, Confidential Oil and Gas Company. Ms. Campsie prepared a GHG IMP for the exploration and production business unit for a large oil and gas company. Using a questionnaire, she developed based on current industry guidelines and calculation methodologies, Ms. Campsie assessed available resources and information to inform the inventory, inventory boundaries and the subsequent steps of determining resource requirements, project planning, and data collection and reporting requirements.

Project Engineer, Confidential Oil and Gas Company. Ashley worked with five different business units (exploration and production, midstream, pipeline, power, and corporate) on an enterprise level to integrate individual group IMP's and information management solutions to create the final rolled up inventory for the entire company.

Project Engineer, CenterPoint Energy, Ashley participated in workshops to identify emission sources and calculation methodologies for greenhouse gas emission inventories. Ashley also assisted with the development of emission inventory spreadsheets and straw man IMPs for the different business groups; Pipeline, Distribution, Electric Distribution, and Corporate.

Prior to Joining CH2M HILL

Environmental Engineer, Duke Energy Field Services. Some responsibilities included air permitting activities for several regions (Utah, Wyoming, Colorado, Kansas, Oklahoma, and Texas) including New Source Review, Title V, and PSD for hundreds of facilities; air compliance for the Rocky Mountain region (Utah, Wyoming, and Colorado) including Title V Compliance Certifications, periodic MACT and Leak Detection and Repair reporting as well as representing facilities in internal and external audits for 50+ facilities; and water and waste permitting including SPCC, Stormwater, and RCRA.

Engineer in Training, Air Pollution Control Division, Operating Permit Unit. Responsibilities included conducting engineering reviews of air pollution operating permit applications, working with state and federal air quality regulations and standards to issue operating permits for industry, and responding to public and U.S. Environmental Protection Agency comments.

Ashley Campsie, PE
Senior Environmental Engineer

Publication

Understanding Air Quality Issues from Shale Oil & Gas Exploration and Production, EM, June 2012.

Presentations

EPA Mandatory Greenhouse Gas Reporting Rule for the Oil & Gas Industry, October 14, 2010

EPA Mandatory Greenhouse Gas Reporting Rule for Energy Sector, April 21, 2011

Air Quality Permitting 101, January 17, 2013

40 CFR Part 60 Subpart OOOO, February 13, 2013

Evolving Environmental Regulations, February 13, 2013

Potential to Emit, Rocky Mountain EHS Peer Group, January 19, 2017

Air Quality Regulation and Compliance, Douglas County Planning Commission Hearing, September 9, 2019

APPENDIX C

DIRECT TESIMONY OF LORI MARQUEZ

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

TESTIMONY OF LORI K. MARQUEZ

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS

A: Lori K. Marquez. 650 South Cherry Street, Suite 510, Denver, Colorado 80246.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am a Senior Air Quality Consultant with Barr Engineering.

Q: DOES YOUR TESTIMONY ADDRESS AIR QUALITY ISSUES?

A: Yes. My testimony relates to air emissions from disposal well operations and certain provisions of the proposed rule that would regulate these emissions.

Q: DOES YOUR EDUCATION AND EXPERIENCE QUALIFY YOU TO TESTIFY ON THIS TOPIC?

A: Yes. I have attached my CV as Appendix A, which describes my qualifications in detail. In summary, I have degrees in engineering and environmental science and have worked in the field of environmental engineering for over twenty-five years. I have developed expertise in the area of air emissions and the regulation of air emission sources through many years of experience.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of NGL Energy Partners LP ("NGL"), Solaris Water Midstream, LLC ("Solaris"), Oilfield Water Logistics SWD Operating, LLC ("OWL"), Goodnight Midstream, LLC ("Goodnight"), and 3 Bear Energy, LLC ("3 Bear"), which I may collectively refer to as the "Commercial Disposal Group" or the "Group."

Q: PLEASE STATE BRIEFLY THE NATURE OF THESE BUSINESSES.

A: As relevant to the New Mexico Environment Department's ("NMED") proposed ozone precursor rules, each company has commercial operations in New Mexico for the recycling and/or underground injection of produced water.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the Group's concerns with monitoring-related requirements proposed by NMED and to propose reasonable alternatives that account for the difference between disposal well operations and upstream operations.

Q: DO YOU OPPOSE NMED'S PROPOSED OZONE PRECURSOR RULES?

A: I oppose certain provisions in NMED's proposed ozone precursor rules, which I will explain in my testimony. Specifically, I will address the proposed rules relating to equipment monitoring tags and related monitoring requirements including the requirement for visual inspection of equipment.

II. EQUIPMENT MONITORING (20.2.50.112 NMAC)

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.112 NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: The equipment monitoring tag requirement is overly burdensome across the industry and, in particular, is not a good fit as applied to operations at commercial water disposal facilities. When applied to these types of facilities, the provisions would impose requirements that are unduly onerous and costly, and provide little environmental benefit.

Q: WHY DO YOU BELIEVE THE EMT REQUIREMENT IS OVERLY BURDENSOME?

A: The EMT program will impose significant startup and recurring costs. Section 20.2.50.112.A.(3) requires operators to install an EMT on a wide range of equipment including storage vessels, control devices, engines, compressors, natural gas wells, glycol dehydrators, natural-gas fired heaters, and pneumatic controller pumps. The cost of installing EMTs on hundreds of emission sources will be significant in itself. The costs and logistical challenges of setting up the program, working through compatibility issues with existing systems, and developing an app to implement the program will also be substantial. In addition, companies will incur large ongoing labor costs to manage and carry out the program in the field, including complying with monitoring requirements. This coupled with new or additional LDAR monitoring such as Method 21, OGI, and visual monitoring will impose significant added costs to operators. These costs would be particularly high at unmanned facilities, which are common in the commercial water disposal industry. While we are not able to estimate the cost to comply with any reasonable degree of accuracy at this time, based on our preliminary conversations with vendors we believe the cost can range from several hundred thousand to several million dollars per year, based largely on the size of the operator along with logistical, technical and compatibility difficulties that may arise for existing facilities.

Q: PLEASE DISCUSS THE ANTICIPATED COSTS OF IMPLEMENTING THE PROPOSED EMT PROGRAM.

A: Costs would include development of an app, tag installation costs, ongoing implementation of the system, and ongoing maintenance/updates. However, the rule as currently written is not clear on all of the information that may be required. The Compliance Database Report (CDR) requirements are not defined, which affects the app development. Our initial communications with potential providers indicated that the cost to develop the app would be highly dependent on the amount and type of data that would be required to be collected. Would operators be collecting the permit limits, manufacturer information, etc.? Does the app need to allow them to edit equipment information, or will there be periodic updates that are done directly in the database? How will the EMT system be utilized with existing data management systems and communications? What type of compatibility issues will arise and how will those be fixed?

The group has not attempted to quantify installation costs, however, it is my understanding that NMOGA estimated tag installation at $281 per tag. While the time for a technician to scan a tag and enter data may not add significant time to the testing/monitoring, the ongoing upkeep of the system could add significant ongoing operations costs to maintain the system. Equipment changes, permit changes, and regulatory changes, would all be potential triggers for updates, and would require additional internal staffing or engaging outside consultants at substantial cost.

Q: WOULD THE BENEFITS OF THE EMT PROGRAM JUSTIFY THE COST?

A: No, not as applied to the Group's operations. Because emissions from disposal wells are very low, the minor emissions reductions that may result from the program are not justified by the anticipated large expense of complying. That said, it is unclear how implementing an EMT program would in itself provide emissions reductions. Emissions reductions resulting from this rule would be tied to the control strategies, monitoring, and testing criteria set forth, not in the methodology of transmittal of information to the state.

Q: PLEASE ELABORATE ON THE EMISSIONS PROFILE FOR DISPOSAL WELLS.

A: Disposal well operations receive post flash water from oil and gas operations. This water has been separated to the extent possible at the producing operations then transported by truck or pipeline to Salt Water Disposal (SWD) facilities for further hydrocarbon removal. SWDs remove remaining hydrocarbons and either inject the treated water or store it in recycling ponds for beneficial reuse. Trace amounts of hydrocarbons remain in the treated water. The recovered oil is transported offsite typically to refineries ultimately for beneficial use.

Typically, incoming water is comprised of about 0.5 percent hydrocarbons, but this can vary. Most producers try to remove as much oil content as their facility operations/designs can accommodate. The SWDs may use a variety of techniques to enhance the hydrocarbon liquids recovery from the water including gravity separation, heat, and chemical treatment. The SWDs by design are intended to recover as many hydrocarbons from the water as possible.

The emissions profile at disposal wells is entirely different than the producing operations that create the incoming water. Producing operations handle multiphase products: gas, oil, and produced water at producing well pressures. Emission sources at production facilities may include flash and working/breathing losses from tanks (oil and produced water), heater treaters (if gas driven), oil loadout, produced water loadout, gas lift compression, vapor recovery unit compression (if gas driven), dehydration, flare/combustor emission controls and process piping fugitives.

The disposal wells do not receive produced gas or oil. The water received from the producing wells has gone through separation and has flashed at the producing operations. Therefore, the water is post flash and at atmospheric conditions.

Emissions sources at disposal wells may include low level working/breathing losses from atmospheric tanks (sand and oil removal tanks or gunbarrels, oil tanks, treated water tanks, and filtered water tanks), recovered oil loadout by truck, and process piping fugitive emissions. The disposal well itself is not an emission point because it is injecting water that has been cleaned and filtered and therefore, contains only trace amounts of hydrocarbons. The heaters are typically electric because SWDs do not have an on-site source of natural gas to power combustion sources.

Q: PLEASE EXPLAIN HOW EMISSIONS FROM DISPOSAL WELL OPERATIONS DIFFER FROM UPSTREAM OPERATIONS.

A: Depending on the capacity, well pressures, and equipment, production facilities generally require vapor recovery and/or emission controls to maintain emissions below Title V thresholds and attempt to maintain tank emissions below NSPS OOOOa thresholds. Some larger production facilities are major under Title V even with various control options applied. Because most processes at production facilities are at pressure, uncontrolled (without LDAR program) process piping fugitive emissions are expected to be larger than they would be at SWDs.

Disposal wells themselves are not emission sources as described above. SWDs are typically true minor facilities, meaning uncontrolled emissions are less than New Source Review and Title V thresholds. Additionally, uncontrolled tank emissions are typically below NSPS OOOOa thresholds (<6 tpy VOC). Process piping fugitive emissions may occur as a result of liquid leaks. Any vapor component leaks would typically be at the top of the oil tanks at thief hatches, pressure vacuum relief valves (such as Enardo), and any other connections at the top of the tanks; however, given that disposal wells inject post-flash water these leaks are not high-pressure leaks.

Q: PLEASE ELABORATE ON YOUR CONCLUSION THAT EMISSIONS BENEFITS FROM THE PROGRAM WOULD BE MINIMAL AS APPLIED TO THE GROUP'S OPERATIONS.

A: It is not readily apparent what environmental benefit would come from the very expensive EMT effort. The requirement to tag each emission unit and scan each compliance event seems redundant to state systems currently in place for reporting compliance events. Many compliance demonstrations are performed by third party contractors; they provide reports that have been properly QA'd, with data in the form of the regulatory requirement. These reports are not generated contemporaneously and often take several weeks to obtain.

Section 20.2.50.112 (A)(9)(a) requires "*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*." The only data that would likely be available in the specified timeframe would be raw data which would not be useful for comparison to standards and would not have been adequately QA'd for submittal. An instantaneous record that a compliance event is taking place is also not particularly useful since the rule itself provides the compliance calendar.

As an example, engine testing is typically performed by third party contractors during scheduled intervals and advance notice of the test is provided to the state. The contractor does the test, collects the raw data on site, then later processes the data and provides a report to the operator that is in a format that compares the results of the test to the applicable standard or permit limitation. It often takes weeks to receive the final report. The raw data collected at the site is of limited practical use because the units are typically not in a form that can be compared to standards or permit limitations. In my professional opinion, these data should not be reported to the state until it has been properly QA'd and processed. The state is already aware of the test from the advance notification so a scan of the EMT tag does not provide added value and comes at considerable cost to the operator.

Q: DO YOU HAVE A PROPOSAL FOR REVISING SECTION 112?

A: Yes. My proposal is to delete sections 20.2.50.112.A.(3) through (10) and section 112.B(3). These proposed revisions are reflected on the Group's <u>Exhibit 1</u> (Redline Showing Recommended Modification to Proposed Regulation). Sections 20.2.50.112.A.(3) through (10) set forth the requirements and specifications for installing EMTs and maintaining them on applicable equipment, as well as reporting and recordkeeping requirements. Section 112.B.(3), which sets forth requirements for using the EMTs and collecting data during monitoring events, should also be deleted as a conforming change. Reporting requirements in applicable sections would need to be revised to utilize existing reporting systems as described below.

Q: WHAT WOULD BE THE IMPACT TO THE COMPANY MEMBERS OF THE GROUP IF THE PROPOSED EMT REQUIREMENTS ARE FINALIZED?

A: The EMT set up and implementation costs mentioned previously, including potential compatibility issues with existing communications systems, would create a substantial burden to the Group. Moreover, the EMT program would be redundant to existing regulatory programs applicable to the Group's operations. There are already state reporting mechanisms in place to submit monitoring and test data. The *Reporting Submittal Form* is currently used to report Title V annual and semiannual certifications, NSPS and MACT requirements, NMAC 20.2.xx or

NESHAP 40CFR61, Permit or NOI requirements, and Enforcement actions. The *Universal Stack Test Notification, Protocol and Report Form* is used to report engine testing. It appears these two reporting mechanisms would be adequate in their current format to report compliance monitoring/testing under the ozone rule.   Given the uncertainty about the feasibility of the EMT program and how the data are supposed to function, it is difficult to characterize the impact to companies with precision. However, we question the need for the program and propose instead that these existing methods be utilized to report monitoring and testing under this rule. This current system would provide the state with the necessary information at substantially less cost.

Q: IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD REGARDING THE PROPOSED REVISIONS TO SECTION 20.2.50.112?

A: No

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

APPENDIX A

CURRICULUM VIATE OF LORI MARQUEZ

Experience

Lori Marquez is an engineer with more than 30 years of experience in the environmental and design engineering fields. Her work has included regulatory analysis, negotiation, permitting, and auditing in support of Clean Air Act, NEPA and the Atomic Energy Act compliance efforts. Lori brings extensive air quality experience, including permitting, compliance, and emission inventories for minor, Title V, and PSD sources across multiple states and industries. She has assisted clients in numerous complex regulatory and compliance issues at Title V and PSD major sources and has assisted clients in the design phase of natural gas processing plants to assure compliance with air regulations. She is well versed in federal regulations such as, NSPS Kb, Dc, IIII, JJJJ, OOOO, and OOOOa; and NESHAP HH, ZZZZ, DDDDD, and JJJJJJ.

Examples of Lori's experience include:

- Providing ongoing support for clients in preparing and submitting permit applications, including minor source, Title V, and PSD facilities in the oil and gas industry, as well as in other sectors, such as manufacturing, agriculture/fertilizer, asphalt, and the federal government. Responsible for all phases of application development including analysis, regulatory review, modeling protocol, modeling (AERSCREEN, GLYCalc, AmineCalc, AERMOD, TANKS, E&PTANKS, Promax, HYSYS), landowner and public notification, and preparation of state specific application forms. Geographical expertise in multiple states and tribal lands.
- Providing air services to U.S. General Services Administration to prepare permit applications and regulatory compliance support for boilers used for building/hot water heat and emergency generators. Project includes 1) federal (NSPS Dc, IIII, and JJJJ; NESHAP ZZZZ and JJJJJJ; Title V) and state regulatory applicability review and current compliance status; 2) permit application preparation and submittal; and 3) recommendations and set up of on-going compliance demonstration documents. Set up plans and procedures for facility modifications to help ensure that 1) purchased equipment complies with regulatory emission standards, 2) permit applications and initial notifications are submitted in a timely manner, and 3) ongoing compliance demonstrations are implemented.
- Performing air quality analyses to support NEPA requirements at several planned surface and underground coalmine operations in Utah. Responsible for developing an analysis method for coal mines in the conceptual design stage. This included establishing a baseline set of assumptions, preparing and obtaining approval of a work plan and modeling protocol, calculating potential emissions, performing nearfield (AERMOD) and far field (CALPUFF) impact modeling, and preparing a technical report and EIS chapter summaries for each location.
- Performing air toxics inventory reporting for polymer and adhesives facility in Texas and preparing air permit application for facility modification.
- Managing and performing air quality analyses for ski area expansions in Mt. Crested Butte, Aspen, Telluride, Steamboat Springs, and Vail, Colorado, Loon Mountain, New Hampshire, and Mt. Bachelor, Oregon, to support NEPA and General Conformity requirements. Developed comprehensive emissions inventories resulting from stationary, mobile, and area sources including operational phase, and construction phase with controlled burn strategies. Performed air quality modeling for complex terrain using various EPA Appendix

A and B dispersion models for PM10, nitrogen oxides and carbon monoxide. Assessed various control strategies to mitigate air quality impacts resulting from the ski area expansions.

- Preparing and submitting annual emissions inventories for oil and gas facilities. Responsible for all aspects of emission inventory development including formulating analysis methodologies, compiling field data, analysis of data, calculation of actual emissions, and preparation of state specific annual emissions inventory forms.
- Managing and performing an air quality analysis for the Carlsbad, New Mexico, BLM RMP.
- Performing an air analysis for a proposed helicopter skiing operation.
- Performing phase 1 and phase 2 beta testing of the Oklahoma emission inventory electronic filing system. Worked with regulators to address and correct technical issues associated with the new system. Efforts facilitated client's annual emission inventory submittal and established a good working relationship with the regulatory personnel.
- Helping a nuclear power client to address environmental compliance issues associated with thermally cutting a large steel structure with potential radioactive contamination and coated with paint containing PCBs. Efforts included a presentation to the EPA and resulted in a mutually acceptable dismantlement approach. Assisted client in ultimate disposal requirements of the specification cut steel pieces.
- Supporting client with preparation and submittal of semi-annual and annual compliance certifications for facilities holding Title V permits. Responsible for all phases of the certification process including interface with field personnel, analysis of monitoring data, review of permit requirements, and report preparation.
- Preparing air quality modeling protocol and performing modeling for a Nevada coalmine operation.
- Helping a client prepare and submit MACT registrations for oil and gas facilities. Met client's rigorous internal deadline for completion of registrations.
- Managing and performing Colorado Springs regional and sub-regional air quality trend analyses for each criteria pollutant. Also performed AIRS data upload quality assurance check and provided technical information for an air quality trends brochure. Air quality trends brochure became a valuable tool for general, public education.
- Managing the meteorological and radiological ambient air monitoring programs at the Rocky Flats Environmental Technology Site. Responsibilities included development of a task plan for the operation, maintenance, data validation, and calibration of several monitoring sites; implementation of the plan; coordination, scheduling, maintenance support, and oversight of the activities. Efforts resulted in key system improvements.
- Managing the Community Radiation Monitoring Program maintenance contract for the DOE. Responsibilities included developing a task plan for the operation and maintenance of several monitoring sites, implementing the plan, recommending system upgrades, coordination, scheduling, and oversight of the activities. Efforts resulted in improved system operation and acceptance of a system upgrades plan.

- Designing a methodology to assess the vehicular related air quality impact of corridor changes in Denver involving several transportation scenarios. Managed the assessment effort and wrote the final report.
- Managing and performing an air quality analysis of traffic changes resulting from a U.S. Post Office construction project in Telluride, Colorado. Results were used to comply with General Conformity and NEPA requirements as part of the Environmental Assessment process and resulted in successful approval of the Environmental Assessment and ultimate construction of the new post office.
- Performing air quality carrying capacity studies for the town of Telluride, Colorado, to facilitate growth-planning activities. Developed comprehensive emissions inventories resulting from stationary, mobile, and area sources. Performed air quality modeling and hot-spot analyses in complex terrain using various EPA Appendix A and B dispersion models. The data were used by planners to establish a growth scenario that would not degrade air quality.
- Supporting development and implementation of the DOE regulatory compliance program for training and qualification of nuclear facility workers involved in radioactive waste management and Rocky Flats Environmental Technology Site closure operations. Efforts resulted in successful documentation of compliance status.
- Managing technical support services for a DOE domestic wastewater facility. Supported a variety of projects including installation of an ultraviolet disinfection system. Outstanding performance resulted in additional projects with increased complexity.
- Serving as a member of the Transportation Conformity Subcommittee to develop initial Regulation 10 Criteria of Conformity for the State of Colorado. Regulation was adopted by the state.
- Co-chairing, with NREL delegate, the R&D Partnerships roundtable session of the Colorado White House Environmental Technologies Conference. Conference was one of a series of regional conferences requested by Vice President Al Gore to foster the development and deployment of innovative technologies that facilitate environmental improvements while generating jobs, exports, and economic growth. Presentation to a host of distinguished guests showcased a successful partnership between government, industry, and academia.
- Developing and managing a strategy to implement the Alternative Fuel Data Collection program in Colorado for DOE - National Renewable Energy Laboratories (NREL). Created temporary data structures to manage data while network database system was developed. Became the leading contractor in the U.S. for data collection to support this program.
- Developing and installing an ambient air filter pack sampling system for long-term use at the University of Colorado Mountain Research Station. System measured trace quantities of nitrogen species in the nanogram/m3 range in ambient air, including levels of particulate nitrate, ammonium and gaseous nitric acid. Utilized dichotomous sampling system (analysis of fine versus coarse particle fractions) for comparison to the filter pack system. Study supported the formation of wet-dry deposition models for the Niwot Ridge Long Term Ecological Research.

- Performing engineering design, configuration management, and project management activities for eight years in the nuclear energy field. Part of the development team that wrote the "Configuration Management Program Plan" for the Fort St. Vrain Simulation Facility. Addressed design control, software control, operation, and quality control of the facility.
- Serving as a member of a task force to streamline the plant design control process for use at the Fort St. Vrain Nuclear Generating Station. Wrote lesson plans and instructed engineering personnel on an improved design control process.
- Serving as the engineering representative of a team that reviewed and revised plant administrative procedures to comply with regulatory requirements. Served as a primary contact for Nuclear Regulatory Commission auditors. Reviewed detailed nuclear qualification files to ensure compliance with regulatory requirements.

Education

MS, Environmental Sciences, University of Colorado
Thesis: Nitrogen Deposition to the Alpine Tundra at Niwot Ridge, Colorado

BS, Electrical Engineering, Purdue University
Emphasis: Control System Design

Training

Oklahoma Department of Environmental Quality E-Permitting training, 2016
BR&E Promax Training, Bryan Research & Engineering, Inc., 2014
16-Hour NSPS Subpart OOOO industry training, 2012
24-Hour Advanced AERMOD, Oris-Solutions Enviro-Mod University, 2008
16-Hour Introduction to Oil and Gas Technology, Baker Hughes, 2008
16-Hour NSR and Title V Permitting, Trinity Consultants, 2006
24-Hour Modeling for Permits, Bowman Environmental, 2005

Affiliations

Board member, Air & Waste Management Association, Rocky Mountain Section

Publications

Sievering, H., Rusch, D., and Marquez L., "Nitric Acid, Particulate Nitrate and Ammonium under Continental, Clean Air Conditions and Nitrogen Deposition to an Alpine Tundra Ecosystem at Niwot Ridge, Colorado", *Atmospheric Environment*, Vol. 30, No. 14, pp.2527-2537, 1996.

Presentations

"Digital Logic Gets Nuked, An Honest and Somewhat Humorous Presentation of Using Life's Detours and Lessons to Create One's Own Version of Success," presented at electrical engineering senior seminar, Purdue University, West Lafayette, Indiana, April 2017.

Colorado White House Environmental Technologies Conference, R&D Partnerships roundtable, Co-chair with NREL delegate, Golden, Colorado, September 1996.

Marquez, L., and Sievering, H., "Atmospheric Loading of Nitrogen to Alpine Tundra at Niwot Ridge, CO", American Geophysical Union Fall Meeting, San Francisco, California, Ref. #H22A-3, 1993.

APPENDIX D

DIRECT TESIMONY OF JILL COOPER

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

TESTIMONY OF JILL COOPER

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A: Jill Cooper, 44 Union Boulevard, Suite 620, Lakewood, Colorado 80228.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am a Senior Principal at Geosyntec Consultants, Inc. I am an environmental consultant for the company, including providing regulatory, strategic, and compliance services for clients. I am an environmental attorney by training and formerly worked at the Colorado Department of Public Health and Environment, including five years at the Air Pollution Control Division as an inhouse legal counsel.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of NGL Energy Partners LP ("NGL"), Solaris Water Midstream, LLC ("Solaris"), Oilfield Water Logistics SWD Operating, LLC ("OWL"), Goodnight Midstream, LLC ("Goodnight"), and 3 Bear Energy, LLC ("3 Bear"), which I may collectively refer to as the "Commercial Disposal Group" or the "Group."

Q: PLEASE STATE BRIEFLY THE NATURE OF THESE BUSINESSES.

A: As relevant to the New Mexico Environment Department's ("NMED") proposed ozone precursor rules, each company has commercial operations in New Mexico for the recycling and/or underground injection of produced water.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the Group's concerns with certain provisions in NMED's proposed ozone precursor rules that would negatively impact their businesses, water conservation efforts, and the broader environment, and to propose reasonable alternatives that will satisfy the purpose of the proposed rules.

Q: DOES YOUR EDUCATION AND EXPERIENCE QUALIFY YOU TO TESTIFY ON THIS TOPIC?

A: Yes. I have attached my CV as Appendix A, which describes my qualifications in detail. In summary, I have a degree in law with an emphasis on environmental and regulatory law and worked in the industry for almost 30 years. A majority of my experience is with air and water permitting, compliance, and regulatory efforts for regulatory agencies, companies (inhouse), and clients. When at the State of Colorado, I was an internal air quality attorney for regulatory and compliance, led in the development of key regulations related to emissions from oil and gas and other relevant sectors, and led the State Environmental Self Audit Law program.

Q: DO YOU OPPOSE NMED'S PROPOSED OZONE PRECURSOR RULES?

I oppose certain provisions in NMED's proposed ozone precursor rules, which I will explain in my testimony. Specifically, I will address the proposed rules relating to (i) the impact of proposed regulations on other media regulations and the use of recycled water, (ii) the background and regulatory history underlying produced water recycling in New Mexico, and (iii) the transfer of ownership compliance evaluation.

Q: PLEASE SUMMARIZE YOUR CONCERNS WITH THE PROPOSED OZONE PRECURSOR RULES.

A: The provisions I address in my testimony am concerned with are not a good fit as applied to operations at commercial produced water disposal facilities and fail to consider the importance of recycling water in the industry. When applied to these types of facilities, the provisions would impose requirements that are overly burdensome or technically infeasible and would likely return little environmental benefit. In fact, the requirements could result in greater environmental impacts if recycled water is no longer economic for companies to use. Thus, companies could revert to using all fresh water for completions operations.

II. <u>PRODUCED WATER MANAGEMENT UNITS (20.2.50.126 NMAC)</u>

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.126.B NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: Section 20.2.50.126.B requires operators to control VOC emissions from each produced water management unit ("PWMU") to less than two tons per year, which is an unreasonable emissions cap that most PWMU operations will be unlikely to meet. The cap will likely have the effect of eliminating recycle ponds from New Mexico and drive recycling operations out of the state. In the State of New Mexico there has been a significant focus on enhancing the use of recycled water in oil and gas operations. This regulation could negate the environmental and policy benefits of these efforts by driving the cost of produced water management above the cost of using fresh water.

Q: WHY WILL THIS REDUCE OR EVEN ELIMINATE RECYCLING PONDS IN THE STATE NEW MEXICO?

A: PWMUs are large in size and their emissions are fugitive in nature. This makes it very difficult to estimate or measure PWMU emissions. In fact, there is no federally specified or state consensus on a method for estimating or measuring emissions from open ponds. The large size and fugitive nature of pond emissions also makes it difficult to control emissions through traditional control devices or control mechanisms. Thus, without an option to control emissions, the recycling operations will either move into another state or the companies will start using fresh water. This will have the impact of potentially increasing the demand for fresh water by 3.9 million barrels of water a year. For example, the industry will likely be over 100 million barrels per year. This is equivalent to the fresh water demands for the annual water use City of 128,000 people.

Q: IS THIS WHY YOU CONCLUDED THAT THE TWO TONS PER YEAR VOC EMISSIONS CAP WILL RESULT IN ELIMINATING RECYCLING OPERATIONS FROM NEW MEXICO?

A: Yes, if water recycling and reuse ponds cannot be operated within the two tons per year VOC cap, they will have to be shut down in New Mexico, and this will thwart water conservation efforts put in place two years ago by the New Mexico legislature.

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.126.B NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: In 2019, the legislature passed H.B. 546, the Produced Water Act, with the intention of bolstering use of recycled produced water for oil and gas operations, in lieu of fresh water resources. The Act implemented various policy measures, all aimed at facilitating, through regulatory clarity and on the ground policy adjustments, a robust shift from reliance on fresh water for hydraulic fracturing to recycled produced water. Notably, the Act passed the New Mexico House of Representatives with unanimous support and the Senate with near unanimous support, garnering praise from House Speaker Brian Egolf as one of the "greatest environmental accomplishments" to come out of the legislature. And, the Act has succeeded, as the industry has turned in bulk from fresh water to recycled produced water to support operations. The New Mexico Oil Conservation Division reports that, since October 2020, 408 wells have been completed at an average of 377,290 barrels of water, and that 55% of that water is recycled produced water, or eighty-five million barrels of water.

Because water recycling is a more sustainable practice than use of fresh water, it should and will continue to become the industry standard. However, the rule as presently written, has the undesired effect of driving this recycle activity out of New Mexico. The draft rule appears to accept as a narrative that a choice must be made between capturing ozone precursor molecules and facilitating continued investment in produced water recycle. The draft rule answers that false choice by likely closing the door on continued investment in produced water recycle in the State in favor of capturing some unknown quantity of additional precursors. This outcome is avoidable.

Q: PLEASE EXPLAIN FURTHER YOUR TESTIMONY OF WHY THE PONDS ARE FUGITIVE AND NOT ABLE TO BE CONTROLLED WITH A COVER?

A: As Ms. Campsie testified, emissions from open ponds cannot reasonably pass through a stack, chimney, vent or other functionally equivalent opening. Attempts have been made in the past to cover recycling ponds and feed lot ponds in order to capture or minimize vapors for both emission and odor purposes. These attempts have failed for the following reasons: i) safety for workers; ii) technical feasibility; iii) compromising the liners for soil and groundwater protection; iv) economics; and v) general maintenance issues.

Q: PLEASE EXPLAIN FURTHER WHY IT IS DIFFICULT TO CONTROL EMISSIONS FROM PWMUS.

A: As already discussed, the large size and fugitive nature of pond emissions makes it difficult to capture the vapors to send to a combustor or carbon filter. A more common and successful approach to minimizing emissions from the ponds is to implement best management practices through the reduction of hydrocarbons in the water prior to entering the pond. When I worked for upstream operators with water impoundments, we worked diligently to try to cover water impoundments. We worked to try to put covers on existing impoundments, but could not find a safe and economic manner to operate with covers. If the facilities are not designed to have a structure in place to support the covers, it was not possible to install and manage the covers. If a structure was to be constructed, it would compromise the liner that is intended to protect soil and groundwater.

Q: DO YOU HAVE OTHER CONCERNS WITH 20.2.50.126.B?

A: Yes. I share Ms. Campsie's concerns with the unusual and inappropriate nature of imposing an emissions cap for regulating PWMUs, and that the more common and appropriate approach found in air regulations is to impose performance standards or best practices, or to require controls, rather than prohibiting activities or emission sources that exceed an emissions cap. In addition, the Clean Air Act is premised on considering the cross-media impacts of regulatory and control decisions. This means that agencies should consider the air, water, waste, and energy impacts of any decision. Thus, in working to require an emissions cap instead of best practices, the State of New Mexico may cause a significant impact to the availability of fresh water for its communities. Specifically, it will likely drive the industry to use fresh water over recycled water.

Q: WOULD YOU SUGGEST A DIFFERENT APPROACH TO REGULATING PWMUS?

A: Yes. In general, the rules should promote rather than prohibit the use of PWMUs for water recycling operations. And the rules should allow operators to manage emissions through removing hydrocarbons before the water reaches the PWMU. This is how the companies have been appropriately managing VOC emissions from PWMUs for years.

Q: WHY IS THAT?

A: As discussed in Mr. Kim's testimony, the members of the Commercial Disposal Group operate PWMUs at which millions of barrels of brine water are recycled each year and returned to oil and gas producers for use in hydraulic fracturing operations. This recycling helps oil and gas producers in New Mexico conserve the State's important freshwater resources. If the cost of managing and providing recycled water becomes more expensive than fresh water, the industry will likely return to using greater levels of fresh water.

Q: DO YOU HAVE SPECIFIC SUGGESTIONS FOR REVISING THE RULE?

A: Yes. As Ms. Campsie is also attesting to, I propose revisions to sections A through D of 20.2.50.126 that will address my concerns. First, the existing provisions for best management practices, good engineering practices, monitoring, recordkeeping, and reporting would apply in all cases. Second, for PWMUs with emissions greater than 25 tons per year of VOC fugitive emissions, the operator would be required to obtain a permit from NMED unless it is a recycling operation registered with the Oil Conservation Division. Such sources would not be subject to 20.2.50 NMAC. The permit would be facility-wide, include point sources located onsite, and consider PWMUs as fugitive emission sources. The fugitive emissions would not count toward the VOC limit in the permit.

Q: HAVE YOU PREPARED REVISIONS TO THE RULE THAT IMPLEMENT WHAT YOU JUST DESCRIBED?

A: I contributed to and support the Group's proposed revisions to Section 126, which are presented by Ms. Campsie in her testimony.

IV. TRANSFER OF OWNERSHIP COMPLIANCE EVALUATION (20.2.50.112.C(3))

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.112.C(3) NMAC AS PROPOSED BY NMED?

A: Yes.

Q: WHAT DOES SECTION 20.2.50.112.C(3) NMAC REQUIRE?

A: This section requires that within three months before the transfer of ownership of equipment regulated under the proposed rule, the current owner or operator must conduct and document a full compliance evaluation of the equipment including a certification by a responsible official as to whether the equipment is in compliance with the proposed rule.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: My concerns are that the proposed compliance evaluation could result in automatic non-compliance, could become very expensive and alters the existing expectations developed within the industry over many years in connection with the sale of commercial produced water disposal and recycling operation assets. Quite often, the acquisition and divestiture negotiations are complicated and variable. This means companies may be required to conduct audits in a preliminary approach, then something ends or delays the final agreement, resulting in potentially significant resource use without value. It also creates an incentive for buyers of assets not to perform their own compliance evaluation and will lead to less robust compliance at acquired assets.

Q: PLEASE EXPLAIN WHY YOU BELIEVE THE PROPOSED COMPLIANCE EVALUATION MAY RESULT IN AUTOMATIC NON-COMPLIANCE.

A: Many transfers are back-dated several months to a year from the actual closing or final transfer dates are not know at least three months prior to transfer. This could create an automatic compliance issue with an evaluation being due before a transfer date is known. In addition, if the evaluation is completed in anticipation of a sale occurring, this could result in multiple evaluations, as deals fall through, or an evaluation that is not representative at the actual time of transfer.

Q: PLEASE EXPLAIN WHY YOU BELIEVE THE PROPOSED COMPLIANCE EVALUATION COULD BE VERY EXPENSIVE.

A: As previously described, due to the timing proposed in this rule, multiple evaluations would be required as deals are brought forth and subsequently abandoned. This could be extremely burdensome as well as expensive. The recent Anadarko/Chevron/Occidental dealings is a perfect example of last-minute changes in acquisitions. The level of evaluation for a certification by a responsible official, in effect, puts Title V level evaluations on minor sources of emissions. Evaluations of that magnitude are more intensive and costly to perform.

Q: PLEASE EXPLAIN HOW THE PROPOSED RULE WOULD ALTER EXISTING EXPECTATIONS IN CONNECTION WITH THE SALE OF ASSETS AND CREATE A DISINCENTIVE FOR BUYERS TO PERFORM COMPLIANCE AUDITS.

A: The proposed rule would disrupt companies' ability to take advantage of the U.S. Environmental Protection Agency's ("USEPA") Audit Policy. Many members of the Group and other companies within the oil and gas industry frequently conduct their own examination and analysis of compliance with New Mexico's air regulations and make voluntary disclosures to USEPA or the State of New Mexico, where appropriate, in order to mitigate potential civil penalty risk under the Audit Policy. However, one limitation of the Audit Policy is that an entity may not self-disclose violations based on reports and certifications that are required to be created or disclosed pursuant to state or federal law. For this reason, I am concerned that future compliance audits they conduct in connection with the acquisition of assets may not be covered by the EPA Audit Policy and that the Group will be forced to rely upon compliance reviews conducted by their sellers, rather than relying upon compliance reviews conducted by their own employees. This will create a disincentive to scrutinize compliance matters at commercial produced water disposal and recycling operations and will curtail efforts by companies to integrate newly acquired assets into their more robust compliance programs.

Q: DO YOU HAVE A PROPOSAL FOR REVISING SECTION 20.2.50.112.C(3) NMAC?

A: Yes, this provision should be removed from the Proposed Rule.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

APPENDIX A

CURRICULUM VITAE OF JILL COOPER

Geosyntec consultants

Jill E. Cooper, JD

regulatory compliance
environmental planning and management
mergers and acquisitions
HSE&S management systems
sustainability and ESG

EDUCATION

Juris Doctorate, University of Colorado, School of Law, Boulder, Colorado, August 1993 to May 1996

Masters of Business Administration (cum laude), American Graduate School of International Management ("Thunderbird"), Glendale, Arizona, January 1990 to January 1991

Bachelors of Marketing (cum laude), Michigan State University, East Lansing, Michigan, September 1984 to March 1988

PROFESSIONAL REGISTRATION / CERTIFICATIONS

ISO 14001 Lead Auditor Certification
Colorado Bar 1996 through present

CAREER SUMMARY

Ms. Cooper has more than 30 years of experience working on sustainability, climate change, community engagement, environmental justice (EJ), environmental health and safety management systems, environmental planning and management, sustainability, and regulatory compliance. Her experience covers a wide array of industries including municipalities, state and federal government, mining, energy, water, manufacturing, and food and beverage.

Prior to joining Geosyntec, Ms. Cooper served as Director of Global Environment, Audit, Data and Reporting at two oil and gas companies. In those roles she:

- Managed a team of air, water, waste (including asbestos and LBP), spills, land, wildlife, HSE audit, data system, reporting, and advocacy specialists;
- Participated in state and federal rulemaking processes representing the company and via various trade associations;
- Led the corporate HSE and PSM compliance and management system audit teams;
- Oversaw the remediation team with over 40 significant locations nationwide and supported negotiations with agencies and other parties;
- Represented the company on interactions with local, state and federal regulators, community and stakeholders on HSE and social issues;
- Led the data management teams and programs to increase the capabilities of data systems, enhance the use of data (analytics), and increase HSE compliance and performance; and
- Was a part of Anadarko Ambassadors' Program that developed, managed and engaged in community programs and efforts.

While at the Colorado Department of Public Health and Environment (CDPHE), Ms. Cooper had several key roles including:

- In-house legal administrator for the State of Colorado Air Pollution Control Division (APCD) for compliance and regulatory matters;
- Led numerous air quality rulemakings, including presenting before the commission and legislature;
- Environment Senior Advisor, which involved participating in multiple rulemakings and engaging in reviewing and commenting on federal rulemakings;
- Represented CDPHE at Environmental Council of States and in federal efforts;
- Director of the State of Colorado's Sustainability Division, that involved leading:
  - Colorado's Environmental Justice Program: developing, managing, and coordinating with local communities, other state agencies, and the US Environmental Protection Agency,
  - Environmental Agriculture Program: developing, managing, and coordinating with local communities, other state agencies, and the US Environmental Protection Agency, and
  - Colorado Environmental Leadership, Pollution Prevention Program, the State's Toxic Release Inventory Program, and Small Business Assistance.

She has applied her regulatory expertise in many roles since as an attorney in private practice representing industrial clients with compliance needs as well as in-house as the Director of Environment for two oil and gas companies. Due to her experience, she has been asked to participate on boards, advisory councils, working groups and in other adviser roles. This includes serving on the City and County of Denver's Sustainability Council from 2004 to present. As a part of the Council, she has been involved with climate, water, social, community and other planning and strategic efforts.

Regulatory Compliance and Support

Ms. Cooper's extensive experience in regulatory compliance began with her roles at the State of Colorado as the Air Division Legal Administrator and Environment Senior Advisor, where she handled a myriad of issues and regulatory matters. Her work in private law and at the oil and natural gas companies involved regulatory compliance responsibilities around: air, water, waste, toxics, wildlife, federal lands (NEPA), safety, process safety, and health. Her experience also encompasses multiple sectors, including the following: manufacturing, energy, water and waste handling, agriculture, food products, mining, universities, and government.

Her ability to understand the needs and expectations of regulators, stakeholders, investors, and companies brings a holistic approach to regulatory compliance strategies. This background is also valuable when working with agencies on rulemakings, permitting, and compliance negotiations. Examples of her extensive negotiation experience include:

Air Pollution Control Division, State of Colorado, *Denver, CO.* Engaged nationally with indoor air regulatory and compliance programs around asbestos, lead-based paint, and other similar programs. Roles included: coordinated between US EPA and Colorado; led on rulemaking processes; and led on compliance negotiations and strategies.

***Air Quality Legal Support**, Nationwide.* While at Faegre & Benson, LLC, supported a utility with a myriad of air quality compliance, regulatory, and strategic matters. The work included federal and state regulatory matters, permitting and compliance, and other internal support.

***Managed Environmental Programs,** Multiple States.* Led compliance management teams in multiple states to create, manage, audit, and improve a range of environmental programs including: SPCC, stormwater, state and federal water discharge, RCRA, air quality, and federal lands.

***Facilitate US EPA, ECOS and STRONGER Oil & Gas Workshop**, Albuquerque, NM.* Supported in the planning for and led facilitation of a workshop with over 60 participants from state and federal agencies, companies, non-governmental organizations, communities and tribes.

***Oil and Gas Air Quality,** Texas, New Mexico, Colorado, Wyoming and Oklahoma.* Supported several clients with air regulatory strategies in multiple states associated, including federal and state regulations, methane gas strategies (i.e., flaring, capture, venting), and criteria pollutant and hazardous air pollutant strategies. This includes supporting on voluntary strategies. This includes supporting technology companies interested in obtaining approval from state and federal agencies for monitoring and generation technologies.

***Colorado Oil and Gas Conservation Commission,** Colorado.* Supported the State of Colorado with understanding, assessing and developing regulatory strategies around environmental regulations and cumulative impacts for oil and gas operations. Oversaw the review and assessment of air quality emissions from various upstream locations conducting continuous emission monitoring.

***Air Quality Compliance and Regulatory Strategy,** Colorado.* Supporting a mining operation with air quality regulatory and compliance strategy involving criteria and greenhouse gas emissions. This involves considering voluntary and regulatory strategies to address short- and long-term needs.

***Multi-agency Refinery Enforcement**, multiple U.S. locations.* State lead for negotiating a complex air quality compliance agreement with four states, U.S. EPA and the company.

***Oil and Gas Air Quality Strategy,** global experience.* Led development of an integrated air quality and compliance strategy, including federal and state regulations, methane gas strategies (i.e., flaring, capture, venting), and criteria pollutant and hazardous air pollutant strategies.

***Mining Water Permit Renewal**, Colorado.* Legal representative in negotiating the renewal of an NPDES permit for a large coal mining operation.

***Groundwater and Soil US EPA Investigation**, Wyoming*. Participated in developing and implementing a strategy to mitigate the impacts of a U.S. EPA investigation on an oil and natural gas field. This was one of U.S. EPA's investigations into potential groundwater and soil impacts from historic and ongoing operations.

In addition, throughout her career she has been engaged in regulatory affairs for health, safety and environment programs. This includes developing internal strategies to encourage regulators to develop appropriate regulations that both solve problems and create opportunities for innovation.

Health, Safety, Environment and Sustainability Management Systems (MS)

Ms. Cooper's management system experience is from both working in-house at several oil and natural gas companies and supporting clients with the development of the environmental, reporting, data, audit and sustainability programs. She also led the enhancement and implementation of in-house HSE audit teams (audits included HSE, PSM and MS elements).

One of her areas of expertise is developing and implementing sustainability management systems (SMS) that are designed "fit-for-purpose" for the client. This means the system needs to be designed and work for the entity's purpose, goals, and needs. The systems are designed as a tool to be integrated into the business and operations to improve efficiency, effectiveness, and performance. Her experience extends into stakeholder engagement, reporting, and response. She has received ISO 14001 auditor certification and was involved in the certification of over 1,200 locations at an oil and gas company. She led EMS audit teams in various roles.

Enterprise Management Information System (EMIS) Development, *nationwide.* This experience includes overseeing the planning, development, implementation, and continual improvement of enterprise management information systems (EMIS). It also involves supporting a client in assessing and identifying Her focus on EMIS development is to maximize the benefits of data systems to improve compliance rates, conduct data analytics, and automate compliance and performance tracking.

Manufacturing client ISO 14001 and 45001 Certification, *Global.* Supported a client in obtaining certification to ISO 14001 and 45001 for the EHS program in Colorado and for their corporate operations which covers four countries.

Liquid Natural Gas (LNG) Client Environmental Management System (EMS), *Texas and Louisiana.* Supported a client in enhancing its EMS and developing programs consistent with ISO 14001 and its internal corporate-wide operational excellence management system.

Environment Planning and Management

Ms. Cooper supports client's maintenance and growth capital project portfolios in the areas of planning, permitting, public-government-media relations, construction, waste management, project commissioning, and compliance obligation management. She has worked with and within organizations to develop and implement risk-based evaluation criteria and processes to identify, assess and mitigate risk.

The overall strategy she brings to clients is to build and implement compliance assurance programs, then measure and report on the performance. This requires developing data systems that support HSE teams to efficiently and effectively use HSE, HR and operations data to identify potential issues before an incident occurs. Ms. Cooper led the HSE data teams in her roles in government and oil and natural gas companies. Most recently, she led the development of a data analytics team focused solely on how HSE and operations data can be used to identify risk and prevent incidents.

Her experience in leading teams to develop strong data systems, then expand the reporting capabilities of the organization. Using data to drive operational and HSE performance and prevent incidents is the first step. Next, the information is used to better disclose relevant information to stakeholders. Ms. Cooper's experience with materiality assessments allow a client to focus external disclosure on the topics that matter the most to key stakeholders. This ultimately leads to the client to better engage stakeholders, including investors, and explain how key risks are being identified, assessed and mitigated on a systematic basis. Ms. Cooper's direct experience with developing and implementing risk tools and systems, then communicating with company leadership and investors, is a significant benefit to clients.

Mergers & Acquisitions

Ms. Cooper's experience includes being involved with HSE-related efforts on M&A activities in assets within the U.S. Responsibilities for these projects included detailed due diligence, environmental liability valuation, transactional support, transition planning, environmental permitting, and asset integration services. Her legal, regulatory and business skills provide unique value to M&A activities in order to identify, assess and mitigate risk.

Greenhouse Gas and Climate Strategy

Ms. Cooper has worked on carbon strategies for most of her career. Starting with leading the carbon strategy for the State of Colorado Department of Public Health and Environment, where she represented the state in developing the first climate change strategies. As an independent consult, she advised a global environmental non-governmental organization on climate strategies for the oil and gas industry. Finally, over the past ten years she has developed and advised on climate strategy when the HSE Global Environmental Director at upstream oil and gas companies.

The topical areas where Ms. Cooper has direct inhouse greenhouse gas and climate experience include:

- Developing greenhouse gas data base systems, reporting protocols and strategies, data analytics, and internal GHG goals embedded in the business strategy;
- Developing and utilizing cost/benefit analysis and risk assessment processes for projects, including assessing carbon benefits;
- Assessment of portfolio 'value at risk' associated with different costs of carbon;
- Participating in the development of climate risk scenarios in response to an investor resolution;
- Advising on the various carbon strategies, including cap and trade, carbon tax and other regulatory strategies;
- Assessment of portfolio 'value at risk' associated with different costs of carbon
- Benchmarking of carbon emissions relative to peers;
- Engaging with internal operations and leadership on climate and carbon risks and strategies; and
- Leading discussions with stakeholders on climate and carbon risks and strategies (including investors, community members, suppliers, customers, and regulators).

In addition, she continued to work to embed the above into the companies' practices and programs, such that it became a part of the regular business and risk processes.

Sustainability and ESG Guidance

Her experience with sustainability and ESG has spanned her career, including monetizing environmental benefits and improving how the economics of environmental projects are assessed. She brings an innovative, business-minded, and strategic approach and skills to projects. It is important to design and implement a "fit for purpose" strategy for organizations. The goal is to integrate sustainability and ESG related topics into the purpose of the organization through assessing risks and opportunities.

Ms. Cooper helps create unique partnerships for sustainable companies to work together to prepare companies for the future. This includes finding opportunities around changes due to climate impacts. Universities and research institutions play an important role in these partnerships, as certain industries have less money invested in research and development. Geosyntec's strong relationship with these groups, puts the company in a great position to make things happen.

She works with clients to help design and execute a coherent, strategic approach to sustainability. Her approach involves working with clients to:

- Incorporate sustainability considerations into wider business strategy and to drive innovation via collaboration, scenario planning, and robust prioritization of risk and opportunity;
- Understand and engage stakeholders to build a successful and sustainable business and more systemic, inclusive approach;
- Design reporting strategies for companies, that allow them to apply reporting frameworks, communicate meaningful sustainability outcomes and impacts to key stakeholders, and use reporting as a tool to improve sustainability performance; and
- Build cultures of integrity beyond compliance, manage the challenges of the new transparency environment, and build stronger and more resilient organizational cultures.

She participated on investor calls while at an upstream company and engages with the ESG investment community to track their priorities. She supports clients with ideas on how to better engage with shareholders and other stakeholders, address their issues, and be more transparent where it matters (materiality assessments). Ms. Cooper was instrumental in the creation and management of the internal team around developing and implementing an ESG strategy and program while working in a company.

Climate Change and Energy Transition Strategies

Her experience with climate and energy strategies has been a part of each of her roles. For her past employers, Ms. Cooper led or engaged on teams to develop climate change and energy transition strategies. This included assessing and providing options around carbon reduction strategies, legislative and regulatory approaches (i.e., cap and trade v. carbon tax), establishing and managing data and reporting systems and programs, engaging with stakeholders (i.e., regulators, legislators, investors, communities), and incorporating it into underlying systems. She works to design fit for purpose strategies based on the organization or company. Different approaches are appropriate depending on the mission of the organization, as well as the risks, costs and liabilities associated with climate and energy strategies. Ms. Cooper is thrilled to be able to bring a myriad of experiences to her clients in this area.

PROFESSIONAL EXPERIENCE

Geosyntec Consultants: Senior Principal, November 2018 – present.

Anadarko Petroleum Corporation: Director Global Environment, Audit, Data, and Reporting, March 2014 - October 2018

Encana Corporation: Group Lead Environment, January 2009 - December 2013
Faegre & Benson LLP: Legal Associate, April 2007 - December 2008
State of Colorado: Senior Advisor to Environment, Director of Sustainability, Air Legal Administrator, March 1996 - March 2007

AFFILIATIONS

Society of Petroleum Engineers (SPE) - 2014 to present - Environment Advisory Committee and Chair of HSSE Drilling Workshop (2018)
Groundwater Protection Council - Induced Seismicity and Produced Water papers working groups
American Petroleum Institute (API) – 2014 through 2018 - EHS upstream, midstream and downstream
IPIECA and IOGP - 2014 through 2018 - various subcommittees
Environmental Water Initiative - 2012 through 2018 (chair for 3 years)
City and County of Denver Mayor's Sustainability Council - 2002 to March of 2021 (no longer lived or worked in the city and county)
Science4 Clean Energy (S4CE) - 2017 to present - Advisory Committee member (EU grant)
University of Colorado School of Business Sustainability Council - 2006 to present
Environmental Council of States Colorado representative - 2002 through 2007
Live-By Living Board Member - 2008 to present

APPENDIX E

DIRECT TESIMONY OF GREG JONES

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

TESTIMONY OF GREG JONES

I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A: Greg Jones, 1512 Larimer Street, Suite 540, Denver, CO 80202.

Q: BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A: I am an Air Compliance Specialist with 3 Bear Energy, LLC.

Q: DOES YOUR TESTIMONY ADDRESS AIR QUALITY ISSUES?

A? Yes. My testimony relates to air emissions from pig launching and receiving operations and proposed Section 20.2.50.121, New Mexico Administrative Code.

Q: BRIEFLY SUMMARIZE YOUR EDUCATION AND EXPERIENCE THAT QUALIFY YOU TO TESTIFY ON THIS TOPIC

A: I have attached my CV as Appendix A, which describes my qualifications in detail.

I, Greg Jones, have degrees in petroleum and civil engineering from an accredited university and am a registered professional engineer (PE) in both Louisiana and Texas. I possess over ten years of drilling, completion and producing engineering and operations experience in both US onshore and offshore energy development environments. In addition, I have over twenty years of multimedia environmental engineering and compliance support experience, including the last fifteen years of providing air quality permitting and compliance support to both upstream and midstream energy operations located within multiple operating basins throughout the US.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING?

A: I am testifying on behalf of NGL Energy Partners LP ("NGL"), Solaris Water Midstream, LLC ("Solaris"), Oilfield Water Logistics SWD Operating, LLC ("OWL"), Goodnight Midstream, LLC ("Goodnight"), and 3 Bear Energy, LLC ("3 Bear"), which I may collectively refer to as the "Commercial Disposal Group" or the "Group."

Q: PLEASE STATE BRIEFLY THE NATURE OF THESE BUSINESSES.

A: As relevant to the New Mexico Environment Department's ("NMED") proposed rules for pig launching and receiving, 3 Bear is a midstream service company that operates pipelines to transport oil, natural gas, and produced water in Lea and Eddy Counties, in addition to other assets. Other members of the Commercial Disposal Group may conduct pig launching and receiving operations in the future.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the Group's concerns with the emissions control and monitoring requirements proposed by NMED for pig launching and receiving operations and to propose reasonable alternatives that achieve cost-effective reductions of ozone precursor emissions.

II. <u>PIG LAUNCHING AND RECEIVING (20.2.50.121 NMAC)</u>

Q: DO YOU HAVE CONCERNS ABOUT 20.2.50.121 NMAC AS PROPOSED BY NMED?

A: Yes.

Q: PLEASE SUMMARIZE YOUR CONCERNS.

A: Proposed Section 20.2.50.121 NMAC requires the control of emissions from pigging activities located within or outside of the property boundary of certain categories of stationary sources. The proposed regulation requires operators to capture and reduce VOC emissions by at least 98%. There are associated logistical and technical issues with the proposed regulation related to controlling the minimal emissions from pigging operations as outlined below.

The proposal imposes burdensome requirements that will be infeasible or very difficult to implement and are unlikely to achieve meaningful emission reductions. While some aspects of the proposal may be appropriate, the rule should not require a 98% reduction of volatile organic compound (VOC) emissions from pigging operations. The rule should rely on best management practices and not establish a VOC reduction percentage target because there are constraints on an operator's ability to install or operate emission control devices at standalone pig launching and receiving sites. In addition, operators should only be required to inspect these operations with EPA Reference Method 21 or optical gas imaging (OGI) cameras annually, if at all, and not immediately before and after each pig launching or receiving operation. The Group is proposing revisions to Section 20.2.50.121 to implement these changes and make certain other discrete revisions.

Q: WILL THE PROPOSED RULE ACHIEVE SIGNIFICANT EMISSIONS REDUCTIONS?

A: We question the benefit of regulating pigging operations due to the limited emissions from these operations. Proposed Section 20.2.50.121.B.(1) makes the rule applicable to operations with a potential to emit equal to or greater than one ton per year (tpy). A stationary source with the potential to emit less than 10 tpy of any regulated air contaminant is not required to submit a Notice of Intent under Section 20.2.73 and is eligible for a No Permit Required determination. It is also notable that for purposes of Title V major source permits under Section 20.2.70, NMED has listed emission points with the potential to emit no more than one tpy as "insignificant activities."

Q: WHAT ARE THE HURDLES TO CONTROLLING EMISSIONS FROM REMOTE PIG LAUNCHING AND RECEIVING OPERATIONS?

A: Pipelines traverse long distances. Pig launchers and receivers are typically in remote locations where there are no other sources of air emissions. It is rare for a combustor or other emissions control device (ECD) to be located at a pig launching and receiving operation and even more rare for electric grid power to be available at these sites. An emissions control device would have to be either installed at each remote location or transported from site-to-site and connected temporarily. Potential control device options may include permanently installed combustors, vapor recovery units (VRUs), or mobile flares. These sites typically lack a supply of fuel gas for the pilot light and do not have sustainable grid power available for electric ignition. As such, operators would need to utilize supplemental fuel, such as propane. The combustion of supplemental fuel would cause additional emissions of nitrogen oxides (NOx) and VOCs, both of which are ozone precursors. In addition, long pipe runs, intermittent vapor flows, and associated low vapor impair the operation of a combustor, portable flare, or VRU.

Q: PLEASE EXPLAIN THE CHALLENGES OF OPERATING A VRU AT REMOTE PIG LAUNCHING AND RECEIVING OPERATIONS.

A: Because sustainable grid power is unavailable at most remote locations, the VRU would have to run on either natural gas, if readily available, or supplemental fuel. In either case, the combustion of the fuel would create both NOx and VOC emissions. Furthermore, VRUs are designed to operate on a continuous process, whereas the depressurizing of pig launchers and receivers is a batch process. As such, the VRU would have to be started up and run very briefly and then shut down. This up and down is not good for the engine and also creates additional emissions because the engine never achieves full loading given the small volume of vapor to be compressed.

Q: COULD A PIG LAUNCHER OR RECEIVER THAT IS COLLOCATED WITH ANOTHER OIL AND GAS FACILITY SHARE AN ECD WITH THAT FACILITY?

A: For pig launching and receiving operations located at oil and gas facilities (compressor stations, gas plants, central tank batteries) owned by the operator performing the pigging operations, it may be possible to route emissions to an ECD that is already present to control emissions from other equipment. However, most pigging and launching receivers at these sites are located in excess of 50' from the control device because of safety concerns. For this reason, in addition to the volume of vapors contained within the launcher/receiver being small, and the vapors having to be regulated to the control device so as not to overpressure the same, the likelihood of the vapors actually reaching the control device is extremely low. If launchers or receivers happen to be located near a well production facility, tank battery, compressor station, or other stationary source not owned by the operator performing the pigging operations, the emissions from the same would typically not be allowed to be routed to the existing ECD at the facility because of potential liability issues. Furthermore, as discussed later in this testimony, the pipeline operator likely will not have an easement or right of way for vapor collection system piping to the stationary source, and, once again, pressure differentials caused by excessive piping length, would prevent vapors from flowing to the ECD.

Q: ARE THERE ANY SAFETY RISKS TO UTILIZING COMBUSTORS OR FLARES AT STANDALONE PIG LAUNCHING AND RECEIVING OPERATIONS?

A: Yes. Combustors and flares, whether permanent or temporary, are usually located in excess of 50’ away from flammable vapors to minimize the possibility of a fire or explosion. In addition, combustion devices are equipped with a knockout drum to prevent the carryover of liquid hydrocarbons from reaching the same. On enclosed combustion devices, such as combustors, in which the pilot flame is often located at the bottom of the device, the knockout drum is typically located at a distance from the combustion device for safety reasons. Because the control device is typically located at a minimum distance of 50’ from the emission source, the volume of vapors contained within the launcher/receiver is small, and the rate at which the vapors are directed will have to be regulated by a control valve so as not to overpressure the control device, the likelihood of the vapors actually reaching the control device is extremely low. As such, the combustor or flare would need to be located significantly closer to the launcher/receiver in an attempt to physically transfer the hydrocarbon vapors to the combustion device; however, because there are no formal regulations governing the location of flares from pressurized vessels, this distance would be operator-specific based on its safety practices.

Q: DO PIG LAUNCHER AND RECEIVER SITES TYPICALLY HAVE SPACE FOR AN ECD?

A: Space constraints are a logistical issue that limits operators’ ability to utilize combustors, flares, or vapor recovery units (VRUs). Most rights of way (ROWs) in New Mexico are limited to 30’ feet for the permanent ROW and an additional 20’ for a temporary ROW, for a total of 50’. The ROW agreements would have to be revised to obtain sufficient space to safely operate a permanent system or portable combustion device. Additionally, most ROW agreements would not allow for the addition of such surface equipment without revising the agreement.

Q: HAVE YOU EVALUATED THE COST OF INSTALLING COMBUSTORS AT PIG LAUNCHERS AND RECEIVERS?

A: The costs are prohibitive. Utilizing cost data provided in Mr. Kim's testimony, the capital and one-time cost associated with installing a combustor at a remote pigging location would be approximately $100,000 with annual associated maintenance costs of approximately $41,000. Annualizing these costs over a period of five years and assuming the combustor achieves a VOC emission reduction of one tpy at a single pigging location, the estimated annualized cost is $61,000/ton of VOC.

Q: IS IT FEASIBLE TO REDUCE VOC EMISSIONS BY 98%?

A: Permanent combustors with a destruction or removal efficiency (DRE) of 98% are typically utilized at gas plants, compressor stations and central tank batteries but are generally not feasible for standalone remote pig launchers or receivers for the reasons I described. Again, because the control device is typically located at a minimum distance of 50' from the emission source, the volume of vapors contained within the launcher/receiver is small, and the rate at which the vapors are directed will have to be regulated by a control valve so as not to overpressure the control device, the likelihood of the vapors actually reaching the control device is extremely low. As such, a manufacturer's guarantee of 98% DRE does not by itself mean that facility-wide emissions can be reduced by 98%.

Q: CAN PORTABLE FLARES REDUCE VOC EMISSIONS BY 98%?

A: In theory, a portable combustion device could be utilized in an attempt to reduce the hydrocarbon emissions from pigging operations launchers or receivers not located at a facility. In this case, the existing launching and receiving barrels would have to modified so that temporary piping could be routed from the same to the portable control device. Again, the control device would be located at a distance from the source which the individual operator's safety procedures require, and the vapors from the launcher/receiver barrel routed in a controlled manner so as not to overpressure the control device. Again, because the volume of hydrocarbon vapors contained in the barrel is small, the likelihood of the same reaching the control device is unlikely. As such, the vapors from the barrel would be released into the atmosphere when the temporary piping is disconnected. In addition, I am not aware of a portable combustion device that is guaranteed by a manufacturer to achieve a DRE of 98% for VOCs. Vendors are hesitant to guarantee a DRE for an individual combustion device when the composition of the gas being combusted could vary from location to location. The vendor guaranteed DRE does not account for emissions that cannot be captured and routed to the flare.

Q: HOW SHOULD THE PROPOSED RULE ADDRESS THESE CONSTRAINTS ON UTILIZING ECDS?

A: The proposed requirement to capture and reduce VOC emissions by at least 98% should be deleted. Operators would still be required to employ best management practices, but removal of the 98% target would avoid the need for infeasible combustors or flares.

Q: HOW SHOULD BEST MANAGEMENT PRACTICES BE APPLIED?

A: The United States Environmental Protection Agency discussed BMPs in a September 2019 Enforcement Alert, publication number EPA 325-F-19-001. The EPA identified BMPs including minimizing the total volume between the kicker and/or bypass isolation valves and the main isolation valve, so that less gas is trapped in the barrel, and minimizing the potential for liquid accumulation or hold-up in the receiver. The EPA explained that "the applicability and effectiveness of these engineering solutions are site-specific." I agree that BMPs are site-specific and cannot be applied universally. Operators must retain the flexibility to select appropriate BMPs for each location.

Q: WHAT ARE YOUR CONCERNS WITH THE PROPOSED LEAK INSPECTION FREQUENCY?

A: The proposal to require Method 21 or OGI inspections of pig launching and receiving operations "immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation" is excessive. Oil pipelines may be pigged as often as weekly, depending on the design, liquid characteristics and operating conditions. Natural gas pipelines may be pigged approximately every two to four weeks, again depending on the design, the amount and characteristics of the liquid entrained in the gas, and operating conditions. Pig launchers and receivers with the potential to emit as little as one tpy do not warrant OGI inspections either before or after pigging operations. For comparison, NMED has proposed annual OGI inspections for wellhead sites with a PTE less than two tpy VOCs, and monthly inspections for sources in excess of 25 tpy of VOCs. Proposed Section 20.2.50.116.C.(3).

Q: HOW WOULD THE PROPOSED INSPECTION FREQUENCY IMPACT OPERATORS?

A: The proposed rule would disrupt the workflow of pigging crews. Operators would have to make a special trip to the receiver immediately before the pigging operation, forcing them to drive additional distances. This additional vehicle traffic increases emissions. Because the launchers and receivers are geographically separated, the additional travel time will significantly reduce the number of pigging operations a crew could perform each day. As such, most operators would be forced to add additional pigging crews. In addition, the operators would either have to purchase and provide each pigging crew with a dedicated OGI camera as well as train each crew on its proper use or contract multiple OGI inspection crews to accompany the pigging crews on a daily basis. For reference, an OGI camera typically costs $100,000, and the cost for a contract OGI inspection crew typically is $4,000 per week.

Q: WHAT IS AN APPROPRIATE LEAK INSPECTION FREQUENCY FOR PIG LAUNCHERS AND RECEIVERS?

A: Most small operators typically contract LDAR-type services, including both OGI and Reference Method 21 inspections, because they neither own the necessary equipment nor have adequately trained personnel to complete the inspections. In regards to pigging operations, a more effective option would be the performance and documentation of an audio, visual and olfactory (AVO) inspection prior to the initiation of pigging operations. If OGI inspections are required for pig launchers and receivers, they should not be more frequent than annually. This is consistent with NMED's proposed inspection frequencies for other facilities with similar emissions. It is also consistent with the New Mexico Oil Conservation Commission's requirement for annual inspections of natural gas gathering facilities.

Q: IS THERE ANYTHING ELSE YOU WOULD LIKE TO ADD REGARDING THE PROPOSED REVISIONS TO SECTION 20.2.50.112?

A: My proposed revisions to 20.2.50.121 NMAC are shown in the Commercial Disposal Group's consolidated redline.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Respectfully submitted this 28th day of July, 2021.

GREG W. JONES, PE

EXPERIENCE

3BEAR FIELD SERVICES, LLC
Air Compliance Specialist, 07/2021 - Present

FRANKLIN MOUNTAIN ENERGY, CUB CREEK ENERGY and VALIDUS ENERGY
Contract Environmental Engineer, 07/2020 – 07/2021

JAGGED PEAK ENERGY and PARSLEY ENERGY
Contract Environmental Engineer, 06/2019 – 05/2020

QEP RESOURCES
Senior Environmental Engineer, 10/2005-10/2018

Provided multimedia environmental engineering and compliance support to both upstream and midstream energy operations located within the states of Colorado, Utah, Wyoming, New Mexico, Texas and Louisiana, including centralized processing facilities and tank batteries; oil terminals; gas compression/dehydration/amine and NGL recovery facilities; refrigeration and cryogenic gas plants; produced water treatment/recycle and disposal facilities; and electrical generating stations. Coordinated with facilities engineering and operations personnel in facility design, including equipment selection and operation. Participated in both the MOC process and process safety start-up reviews.

- Prepared applications and secured local, state and federal air construction and operating permits. Negotiated site-specific permit requirements and conditions with regulatory agencies. Assisted operations personnel with attaining and maintaining compliance with permit requirements and applicable local, state, and federal environmental regulations.
- Managed and coordinated the monitoring, testing and recordkeeping and performed the notification and reporting requirements, as applicable, for 40 CFR 60 (NSPS) Subparts Dc, OOOO, OOOOa, IIII, JJJJ and KKKK in addition to 40 CFR 63 (NESHAP) Subparts ZZZZ, KKK and HH. Prepared and submitted the annual GHG report as required by 40 CFR 98 Subparts C, W and NN.
- Provided interpretation of and technical direction concerning applicable local, state and federal air quality requirements, including NSPS and NESHAP regulations, applicable to upstream and midstream energy operations to environmental professionals, management staff, and operating personnel. Developed 'white papers' for aiding in ensuring understanding of and compliance with the same.
- Facilitated technical and strategic support to counsel, operations, and management in response to US EPA and Department of Justice's legal claims for alleged violations to Clean Air Act for five midstream facilities. Negotiated and implemented the requirements of a Consent Decree, which allowed the settlement of claims.
- Managed the corporate audit process for assessing compliance with applicable local, state and federal health, safety and environmental regulations, corporate policies, and environmental management system (EMS) standards and procedures.
- Completed environmental reporting requirements, including air compliance certifications, air emission inventories, Section 312 (Tier 2) reports under EPCRA, and quarterly discharge monitoring reports (DMRs) for storm water discharges. Prepared and certified SPCC pans as a professional engineer (PE).

WEYERHAEUSER COMPANY
Environmental Engineer, 10/1998-10/2005

Provided multimedia environmental engineering and compliance support to wood products and pulp and paper manufacturing facilities located throughout the US. Prepared applications and secured permits for minor, major and PSD air emission sources. Secured and managed the monitoring, recordkeeping, and reporting requirements for storm and industrial wastewater NPDES permits. Designed closure and groundwater monitoring plans for surface impoundments and landfills and provided on-site supervision and project management to ensure proper closure.

PPM ENVIRONMENTAL CONSULTANTS
Staff Environmental Engineer, 06/1997-09/1998

Managed multiple sites contaminated with chlorinated and petroleum-based constituents. Designed and supervised installation and operation of soil vapor and dual-phase vacuum extraction, pump and treat, natural attenuation, excavation, and activated biological treatment systems.

VARIOUS U.S. UPSTREAM OPERATORS
Petroleum Engineer/Operations Supervisor, 01/1985-08/1995

Provided drilling, completions and producing engineering and onsite operations supervisory support to US onshore and offshore energy operations.

EDUCATION

LOUISIANA TECH UNIVERSITY, Ruston, Louisiana
Master of Science, Civil Engineering, 1997

LOUISIANA TECH UNIVERSITY, Ruston, Louisiana
Bachelor of Science, Petroleum Engineering, 1984

CERTIFICATIONS

OSHA 511 (General Industry) Certification
OSHA 5810 (Oil and Gas Industry) Certification

LICENSURE

Registered Professional Engineer, Louisiana, E-28181, and Texas, PE 121293

APPENDIX F

EXHIBIT LIST

Exhibit	Description	Presenter
1	Redline Showing Recommended Modification to Proposed Regulation	All witnesses
2	Typical Produced Water Management Unit Design – Attachment B to Direct Testimony of Il Kim	Il Kim
3	Typical Disposal Well Operation – Attachment C to Direct Testimony of Il Kim	Il Kim
4	Streams with High Moisture Content – Attachment D to Direct Testimony of Il Kim	Il Kim
5	Cost Estimate of the Economic Impacts – Attachment E to Direct Testimony of Il Kim	Il Kim

EXHIBIT 1

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 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, 2021, 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, 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 (RM21) (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 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. 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 wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, 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, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

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.

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.

M. **"Department"** means the New Mexico environment department.

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 fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, 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 that collects or moves natural gas, crude oil, or 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 between a storage vessel and 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 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.

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

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

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

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

EE. “Pneumatic controller” 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.

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.

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

HH. “Produced water” means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

II. “Produced water management unit” means a recycling facility or a permanent pit 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.

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.

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.

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.

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.

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.

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.

PP. “Startup” means the setting into operation of air pollution control equipment or process equipment.

QQ. “Stationary Source” or "source" means any building, structure, equipment, facility, installation (including temporary installations), operation, or 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.~~

RR. “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 railcar, a process vessel such as a surge control vessel, bottom receiver, or knockout vessel, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

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

TT. “Wellhead site” means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead 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 crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid ~~Or produced water~~ in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

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~~. 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 refinery and transmission pipelines 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 good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. 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.

(2) Sources 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 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 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 of the source;~~

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

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

~~**(e)** for a control device, the controlled VOC and~~ NO_x ~~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.~~

~~**(4)** The 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.~~

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

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

~~**(8)** If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.~~

~~**(9)** The owner or operator shall contemporaneously track each compliance 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.~~

~~**(b)** data required by this Part shall be maintained in the database for at least five years.~~

~~**(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. 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.~~

B. Monitoring requirements:

(1) 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.

(2) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy, such as audio, visual, and olfactory (AVO) monitoring. 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 the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

~~**(3)** Each monitoring event (e.g. testing, inspection, parametric monitoring) shall 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~~ monitoring 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~~ ten business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the 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)** 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 ~~24 hours~~five business days of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information to the department~~either 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~~.

[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 wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

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.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines 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:

(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 meets 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 meets 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 NOx and VOC emissions are reduced by at least ninety-five percent per year.

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

NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
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, 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	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	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.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

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

(~~10~~9) The owner or operator of an emergency use engine that is operated less than 100 hours per year for non-emergency situations, 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.

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. 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) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer 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.

(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 shall be demonstrated by performing an initial emissions test, followed by subsequent ~~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

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

(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 or 3 years of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per Year for non-emergency situations, shall monitor the hours of operation by a non-resettable hour meter.

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

~~**(7)** Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 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, and serial number~~, and EMT~~ for the engine or turbine;

(b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;

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

(i) the date and time of an inspection, maintenance or repair;

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

(iii) the name of the personnel 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. The records shall include:

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

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

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

(e) the analytical or test methods used;

(f) the results of analyses or tests;

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

(3) The owner or operator of an emergency use engine operated less than 100 hours per year for non-emergency situations, 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 to meet the requirements of Paragraph (2) 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's actual hours of operation, to demonstrate 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, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites 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 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 shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-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.~~

(~~6~~5) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

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 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 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 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 identification 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 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 initial startup or the last rod packing replacement;

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

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of 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:

A. Applicability: These requirements apply to control devices 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 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 used to comply with this Part at least

~~monthly~~ semi-annually to ensure proper maintenance and operation. ~~Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.~~

(~~5~~4) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(~~6~~5) 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 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 certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system 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."

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

(a) manufacturer name, make, and model;

(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 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) 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.

(e) the owner or operator shall repair the flare within three business days of any 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 annually ~~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; and

~~**(d)** prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and~~

(~~e~~d) 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 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 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 gas analysis for the gas being flared, including VOC content and heating value; 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 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 an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. 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.

(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~~annually, 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.

~~**(c)** prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.~~

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

(a) any instance of 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 conducting the inspection, and any maintenance activities performed;

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

(c) the results of 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.

(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 EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 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 conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(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 shall maintain a record of the following:

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

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

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

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC.

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

C. Default Monitoring 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 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 a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

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

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

(d) any positive detection during the AVO inspection shall be 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.

(2) The owner or operator of a facility with an annual average daily production 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 audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

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

(a) for wellhead sites or tank battery facilities:

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

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

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

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

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

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

(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;

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

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

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

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

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

(6) 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.

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 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 monitoring under that plan.

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

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

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 until the component has been repaired;

(2) leaks shall be repaired within 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 discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 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.

F. Recordkeeping requirements:

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

(a) facility location;

(b) date of inspection;

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

(d) name of the personnel performing the inspection;

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

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

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

(a) the date the leak is detected;

(b) the date of attempt to repair;

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

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

(ii) signature of the authorized representative 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 including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

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

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown;

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

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

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during 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.

~~**(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 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 or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during 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.~~

(~~4~~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 records for liquid unloading:

(a) identification number and location of the well;

(b) 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 or atmosphere;

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

(g) the type of control device used to control VOC emissions during the liquid unloading; and

(h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of 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 wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 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 no later than two years after the effective date. 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 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 natural 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;

(c) still vent and flash tank emissions shall not be vented to the atmosphere; 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) 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.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location 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 identification number of the control device or process the emissions are being routed;

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

(g) a copy of the glycol dehydrator manufacturer 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 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 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	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one 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;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, 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 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 scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location 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 the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel 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.

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 with an uncontrolled PTE equal to or greater than two tpy of VOC emissions and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part. Owners or operators of hydrocarbon liquid loading transfers for which the use of air pollution control equipment would be technically infeasible, including but not limited to the fact that such equipment would not operate without supplemental fuel, may apply to the department or an exemption from the control requirements of Section 20.2.50 NMAC. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the hydrocarbon liquid loading monitoring requirements. Without limitation, evidence submitted by an applicant under this paragraph for an exemption based on technical infeasibility of a combustor demonstrating that emissions to be controlled from hydrocarbon liquid transfers are below the minimum BTUs specified by the manufacturer of the combustor to operate the combustor without the use of supplemental fuel, shall constitute technical infeasibility. All other applications will be considered on a case-by-case basis.transfers for which the use of air pollution control equipment would be technically infeasible, including but not limited to the fact that such equipment would not operate without supplemental fuel, may apply to the department or an exemption from the control requirements of Section 20.2.50 NMAC. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the hydrocarbon liquid loading monitoring requirements. Without limitation, evidence submitted by an applicant under this paragraph for an exemption based on technical infeasibility of a combustor demonstrating that emissions to be controlled from hydrocarbon liquid transfers are below the minimum BTUs specified by the manufacturer of the combustor to operate the combustor without the use of supplemental fuel, shall constitute technical infeasibility. All other applications will be considered on a case-by-case basis.

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 percent when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the 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.

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

(5) Connections of hoses and pipes used during 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.

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

(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 shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation. At unmanned locations, the owner or operator shall visually inspect the transfer equipment weekly to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking.

(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 by the operator or owner of the equipment 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).

(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.

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:

(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 time and date of the inspection and testing;
(b) the name of the personnel conducting the inspection and testing;
(c) a description of any problem observed during the inspection and testing; and
(d) the results of the inspection and testing and a description of any repair or

corrective action taken.

(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.

(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:** Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. **Emission standards:**

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting 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 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 emissions to the atmosphere; 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 a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton 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 pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(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) 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 pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the 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; and

(c) 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 wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 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 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES

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 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 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 engineer.

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

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic 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 pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

~~**(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 pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller 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 controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO 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~~ monitoring records shall ~~be linked to a database that~~ contain~~s~~ the following:

(a) pneumatic controller 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 pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO 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 shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 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 pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of 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 pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the personnel conducting the inspection;

(d) AVO inspection result;

(e) AVO 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 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 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: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC except as provided in (9) below.

B. Emission standards:

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

(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.

(3) A new storage vessel with a PTE equal to or greater than two tpy 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.

(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.

(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.

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

(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open 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.

~~**(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.~~

(8~~9~~) An owner or operator complying with Paragraphs (1) through (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.

(9) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible, including but not limited to the fact that such equipment would not operate without supplemental fuel, may apply to the Division for an exemption from the control requirements of Section 20.2.50 NMAC. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements. Without limitation, evidence submitted by an applicant under this paragraph for an exemption based on technical infeasibility of a combustor demonstrating that emissions to be controlled from a storage tank are below the minimum BTUs specified by the manufacturer of the combustor to operate the combustor without the use of supplemental fuel, shall constitute technical infeasibility. All other applications will be considered on a case-by-case basis.

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

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). 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)** scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;~~

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

(5~~6~~) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

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

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (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 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 inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the personnel conducting the inspection;

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

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

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

(4) An owner or operator complying with the requirements in Paragraphs (1) through (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 (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 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 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 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) identification number and location 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 management practices used to minimize release of VOC before and during the workover; and

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

(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 all residents located within one-quarter mile of the well of the planned workover at least three calendar days 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 (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 VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;

(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. Except that a facility which includes a produced water management unit equal to or greater than 25 tons per year of VOC emissions shall obtain a permit from the Department and is not subject to 20.2.50 NMAC. Sources located at a facility or containment that are permitted or registered with the State of New Mexico, Oil Conservation Division as a recycling facility or containment are not subject to 20.2.50 NMAC.

B. Emission standards:

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

(2) The owner or operator shall either:

(a) control VOC emissions from each produced water management unit to less than two tons per year; or

(b) obtain a no permit required determination, file a notice of intent, or obtain a permit from the department.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the ~~monthly rolling 12-month~~ total of actual VOC emissions in tons from each unit on an annual basis;

(2) ~~monthly~~annually, record~~monitor~~ the best management and engineering practices implemented ~~to reduce emissions~~ at each unit to ~~ensure~~ demonstrate their effectiveness.~~; and~~

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

D. Recordkeeping requirements:

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

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) ~~a record of the monthly rolling 12-month total VOC emissions from each unit~~an annual record of the best management and engineering practices implemented at each unit to demonstrate the effectiveness.

~~**(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

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 information obtained by the department 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.

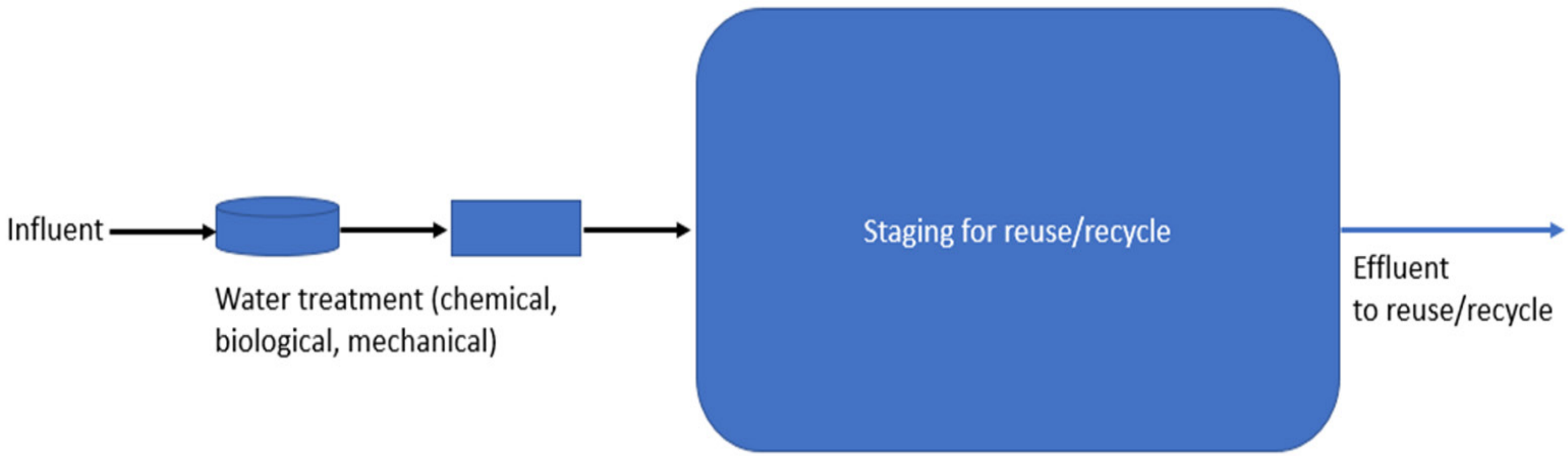
C. If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information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

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

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

EXHIBIT 2

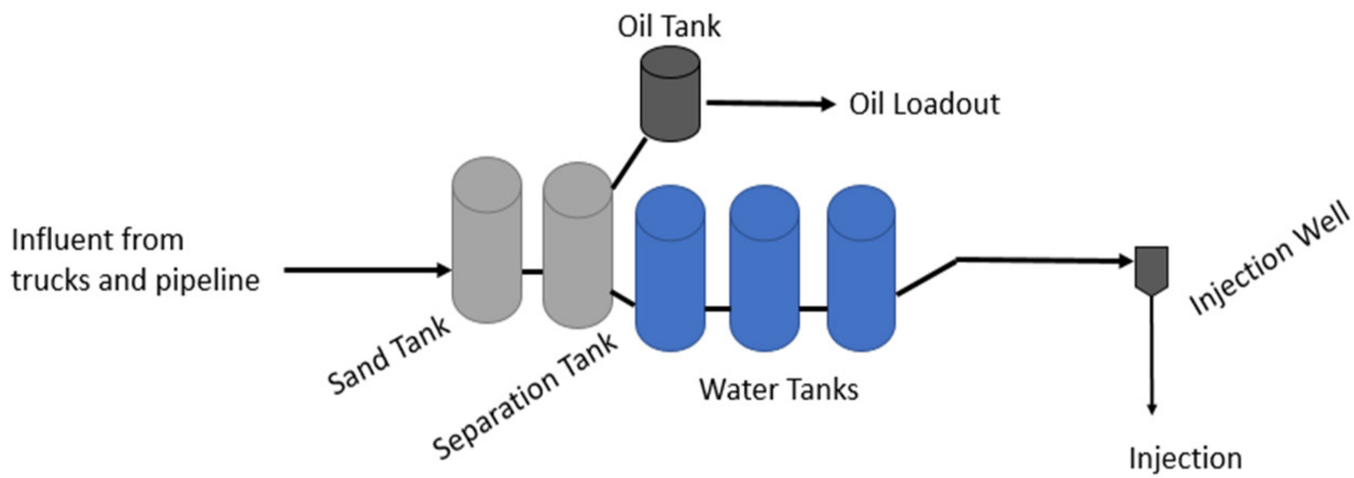
Typical Produced Water Management Unit Design



Attachment B

EXHIBIT 3

Typical Disposal Well Operation



Attachment C

EXHIBIT 4

To:

IL KIM
NGL Energy Partners

Date: 7/27/2021

When flaring streams with the potential to have high moisture content and with a Lower Heating Value (LHV) ≤ 1200 BTU/scf, if the streams are sent to an enclosed natural draft combustor we recommend that the customer include an additional connection for injection of assist gas.

The recommended (ideal) operating temperature for our natural draft enclosed combustors is approximately 1800 F. The purpose of the assist gas is to offset the amount of heat removed by the moisture (latent heat of evaporation) and ensure that the temperature in the combustion chamber does not drop below 1600 F.

For streams with high moisture content we also recommend to apply rigidizer paint to protect the ceramic fiber insulation of the combustion chamber.

Please do not hesitate to contact the undersigned should you have any further questions,

Best Regards

Giorgio Sibilia
Cimarron | Combustion Products

(Cell) 512-247-1557
gsibilia@cimarron.com

ATTACHMENT D

EXHIBIT 5

*These costs are preliminary estimates that are subject to change based on further engineering analysis and further communication with vendors.

Cost to Control Tank Emissions:

	Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Included in EIA	48" Cimmeron Combustor HV ECD 12MMBTU/hr	$ 28,000.00				Estimate provided by manufacturer. Includes freight, platform and installation. This estimate does not include the cost of a blower which would likely be required due to the low pressures throughout the system. In the short timeframe, we were not able to obtain a cost estimate from a vendor.
Included in EIA	Engineering		$ 7,500.00			50 hours @ 50/hour for engineer labor.
Included in EIA	Flare Install		Included above			Using value provided by CDPHE in the 2020 EIA
Included in EIA	Auto-igniter	$ 1,817.00				Using value provided by CDPHE in the 2020 EIA
Included in EIA	Pilot fuel			$ 9,619.04		25 scf/hr * 0.0278 gallons/scf = 0.695 gal/hr; 0.695 gal/hr *24 hr/day = 16.68 gal/day; 16.68 gal/day * 365 days/year = 6088.2 gal/year; (6088 gal/year) / (400 gal/tank) = 15.22 fills per year). prices fluctuate in the year between 1.20 and 1.60 a gallon . a 500 gallon tank of propane holds 400 gallons of propane 1 fill is $550 average. (6088 gal/year* $1.58/gal = $9619.04)
Included in EIA	Flare maintenance			$ 30,127.74		Flare and associated piping maintenance. Labor is estimated at 0.5 hours per 8-hour shift. Maintenance materials costs are assumed to equal maintenance labor costs.
Additional Costs	Propane transportation			$ 1,620.00		As the Division states in the Initial EIA, "[c]lass II disposal well facilities without a supply of well gas need to supplement with propane or other gaseous fuel to maintain the flare pilot light and assist in combusting the loadout vapors, which adds to the expense of the control device operation. The Division does not have information on the cost of transporting fuel to assist the flare or the number of sites without onsite well gas. Therefore, the Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions." Estimate 10 dollars a month for a wireless gauge service that alerts the company of when tanks need filled. ($10/month auto gage * 12 months = $120) + ($100 delivery fee * 15 = 1500) = $1620/ year
Additional Costs	Power Extension		$ 10,000.00			This is an estimate to re-route power to the auto-igniter, assuming power is already on location.
Additional Costs	Pipe, parts & fittings, vapor manifolding lines together and routing to combustion device		$ 30,000.00			Piping required due to storage tanks not being connected via vapor manifold. Operators would also need to install supports on the tanks and piping. This includes labor and material and would be a multiple day project. Typically there are 10-20 process tanks and approximately 5 recovered oil storage tanks at commercial class II disposal well facilities.
Additional Costs	Tank Upgrades	$ 510,840.00				Assumes replacement of 20 fiberglass tanks per site. 750 bbl tanks.
Additional Costs	Knock out pot	$ 20,000.00				A specific type of knock-out pot is required to pull off water laden vapor. This also includes return line otherwise it will bog down the system.
Additional Costs	Installation of propane tank and barrier	$ 1,500.00	$ 1,000.00			Estimate from vendor includes materials, formed, and poured. 1500 for the tank not including pouring the pad, and then an additional $1000 to pour concrete pad.
	Subtotal	**$ 562,157.00**	**$ 48,500.00**	**$ 41,366.78**		
	Annualized Cost	**$ 77,912.27**	**$ 3,233.33**	**$ 41,366.78**	**$ 122,512.38**	

Class II disposal well facilities are unable to accurately evaluate emission reduction per $1, as the industry does not expect that it could meet the destruction efficiency of 95% due to the vapor composition.

Tank uncontrolled Actual VOC Emissions	Annualized Cost	Emission Reduction	VOC Cost control ($/ton)
>2 ≤ 3 tpy	$ 122,512.38	$ 2.38	$ 51,584.16
>3 ≤ 4 tpy	$ 122,512.38	$ 3.33	$ 36,845.83
>4 ≤ 5 tpy	$ 122,512.38	$ 4.28	$ 28,657.87

This is assuming combustion would be 95%, but as discussed in the JIWG PHS, it is unlikely the control device would achieve the destruction efficiency of 95% due to vapor composition.

Attachment E

This cost estimate includes the costs of AIMM, AVO, and associated recordkeeping as this is the first time class II disposal well facilities would be required to implement those programs.

As the Division states in its Initial EIA, "[t]here will be costs related to data collection and associated recordkeeping and reporting requirements. **The Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions.**"

AIMM (either Contractor AIMM *or* in-house AIMM)

Contractor AIMM

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Semi-annual Inspection			$ 1,952.97		Estimate provided by consultant
Repair Confirmation			$ 1,559.50		Estimate provided by consultant
Recordkeeping / Data Management			$ 752.00		Estimate provided by consultant
Subtotal	**$ -**	**$ -**	**$ 4,264.47**		
Annualized Cost	**$ -**	**$ -**	**$ 4,264.47**	**$ 4,264.47**	

OR

In-House AIMM

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
FLIR Camera	$ 122,000.00				Modeled after prior Division EIA
FLIR Camera Maint/Repair:			$ 7,500.00		
Photo Ionization Detector	$5,000				
Vehicle (4x4)	$ 22,000.00				
Inspection Staff			$ 75,000.00		
Supervision (@20%)			$ 15,000.00		
Overhead (@10%):			$ 7,500		
Travel(@15%):			$ 11,250		
Recordkeeping (@10%):			$ 7,500		
Reporting (@10%):			$ 7,500		
Fringe (@30%):			$ 22,500		
Subtotal	**$ 149,000.00**	**$ -**	**$ 153,750.00**		
Annualized Cost	**$ 39,879.12**	**$ -**	**$ 153,750.00**	**$ 193,629.12**	

Emission reduction unknown.

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Emissions Inventory Recordkeeping & Reporting					
Record Keeping set-up, inventory specs		$ 2,064.00			Estimate provided by consultant
Monthly Emissions Inventory Records			$ 1,128.00		Estimate provided by consultant
Annual Report			$ 317.00		Estimate provided by consultant
Supervision (@15%)		$ 309.60	$ 216.75		Estimate provided by consultant
Weekly AVO Inspections					
Average per facility		$ 451.00	$ 23,452.00		Estimate provided by consultant
Cost of Supplemental Off-ramp Analysis					
Average per facility:		$ 1,318.47			Estimate provided by consultant
EF Development		$ 516.00			Estimate provided by consultant
Additional APEN preparation		$ 564.00			Estimate provided by consultant
APEN Submittal		$ 216.00			Submittal fee
Subtotal	**$ -**	**$ 5,439.07**	**$ 25,113.75**		
Annualized Cost	**$ -**	**$ 5,439.07**	**$ 25,113.75**	**$ 30,552.82**	

Emission reduction unknown.

Cost to Control Loadout

	Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs	Notes and Assumptions
Included in EIA	48" Cimmeron Combustor HV ECD 12MMBTU/hr	$ 28,000.00				Estimate provided by manufacturer. Includes freight, platform and installation. This estimate does not include the cost of a blower which would likely be required due to the low pressures throughout the system. In the short timeframe, we were not able to obtain a cost estimate from a vendor.
	Engineering		$ 7,500.00			50 hours @ 150/hour for engineer labor
	Auto-igniter	$ 1,817.00				Using value provided by CDPHE in the 2020 EIA
	Pilot fuel			$ 9,619.04		25 scf/hr * 0.0278 gallons/scf = 0.695 gal/hr; 0.695 gal/hr *24 hr/day = 16.68 gal/day; 16.68 gal/day * 365 days/year = 6088.2 gal/year; (6088 gal/year) / (400 gal/tank) = 15.22 fills per year). prices fluctuate in the year between 1.20 and 1.60 a gallon . a 500 gallon tank of propane holds 400 gallons of propane 1 fill is $550 average. (6088 gal/year* $1.58/gal = $9619.04/year)
	Flare maintenance			$ 30,127.74		Flare and associated piping maintenance. Labor is estimated at 0.5 hours per 8-hour shift. Maintenance materials costs are assumed to equal maintenance labor costs.
Additional Costs	Propane transportation			$ 1,620.00		As the Division states in the Initial EIA, "[c]lass II disposal well facilities without a supply of well gas need to supplement with propane or other gaseous fuel to maintain the flare pilot light and assist in combusting the loadout vapors, which adds to the expense of the control device operation. The Division does not have information on the cost of transporting fuel to assist the flare or the number of sites without onsite well gas. Therefore, the Division requests that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions." Estimate 10 dollars a month for a wireless gauge service that alerts the company of when tanks need filled. ($10/month auto gage * 12 months = $120) + ($100 delivery fee * 15 = 1500) = $1620/ year
	Power Extension		$ 10,000.00			This is an estimate to re-route power to the auto-igniter, assuming power is already on location.
	Pipe, parts & fittings, vapor lines		$ 11,000.00			Installation of vapor lines.
	Installation of propane tank and barrier	$ 1,500.00	$ 1,000.00			Quote from vendor includes materials, formed, and poured. 1500 for the tank not including pouring the pad, and then an additional $1000 to pour concrete pad.
	Subtotal	**$ 31,317.00**	**$ 29,500.00**	**$ 41,366.78**		
	Annualized Cost	**$ 4,340.39**	**$ 1,966.67**	**$ 41,366.78**	**$ 47,673.84**	

Tank uncontrolled Actual VOC Emissions	Annualized Cost	Emission Reduction	VOC Cost control ($/ton)
>2 ≤ 3 tpy	$ 47,673.84	$ 2.38	$ 20,073.19
>3 ≤ 4 tpy	$ 47,673.84	$ 3.33	$ 14,338.00
>4 ≤ 5 tpy	$ 47,673.84	$ 4.28	$ 11,151.77

This is assuming combustion would be 95%, but as discussed in the JIWG PHS, it is unlikely the control device would achieve the destruction efficiency of 95% due to vapor composition.