STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

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

DIRECT TESTIMONY OF THOMAS ALEXANDER

Introduction

Q: **Please state your name, place of employment, position and responsibilities**.

A: Tom Alexander. I have been a consultant to EDF for the past 5 years working on: Underground gas storage, flaring, venting, conventional and unconventional regulations (in eastern states mostly). I assisted EDF in their advocacy before the New Mexico Oil Conservation Commission last January when the Commission adopted its flaring and venting rule. I have also assisted EDF in its contributions to the Interstate Oil and Gas Compact Commission and Energy Resources, Research and Technology committee and two American Petroleum Institute work groups on risk management, Health, Safety and Environment, security and training.

Q: **Please describe your educational background and general work experience**.

A: In total I worked for SWN for 18 years (1998 – 2016) first as a consultant and then as a staff production and completion engineer, team leader for their Fayetteville Shale discovery team and Completion Manager. More recently, from late 2012 to 2016, I served as Vice President of Health, Safety & Environment for SWN. I also worked for SWN's Canadian subsidiary, SWN Resources Canada in New Brunswick, Canada as the General Manager from mid 2010 through most of 2012. Prior to SWN, I worked for New Prospect Company and Revere Corporation in Fort Smith, Arkansas, Habersham Energy Company in Englewood, Colorado, Southwest

Operating, Incorporated and Altair Energy Corporation in Tyler, Texas and Schlumberger Offshore Services in Houston, Texas. From 1975 to 1981, I served in the United States Air Force as a B-52H Navigator and Radar Navigator.

I received a Bachelor of Arts, Psychology from Wake Forest University (1973). I did post-graduate work in chemistry and genetics at Duke University (1973). I received a Master of Science, Mining Engineering (1981) and a Bachelor of Science, Mining Engineering (1981) from South Dakota School of Mines and Technology. I completed the course work for Master of Arts, Environmental Policy and Management at the University of Denver (1994).

My resume is attached as EDF Ex. KK.

Summary of Testimony

Q: Please summarize the testimony you will give.

A: In summary, my testimony will reflect the following:

- There are areas for improvement in the NMED proposed rule as indicated by the revisions EDF proposes to the leak detection and repair provisions and pneumatic controller provisions. In addition, EDF proposes two additional provisions, one to require control of emissions during flowback and the second to require the use of auto gauges.
- With respect to EDF's LDAR proposals, I will speak to the reasonableness of EDF's proposal that operators inspect gas-powered pneumatic controllers when conducting leak inspections and the reasonableness of requiring frequent inspections at well sites near homes and other "occupied areas."

- My testimony will also discuss EDF's proposal that requires operators use vapor tight flowback vessels equipped with a control device, such as a flare, capable of destroying hydrocarbons by at least 95%, and equipped with safety relief systems to control emissions during flowback.
- I will also discuss why New Mexico should follow Colorado's lead and require a shorter (i.e., four years) timeframe to retrofit existing gas-powered pneumatic controllers to zero bleed devices, and increase the number of pneumatic devices that must be zero bleed.
- Lastly, I will speak to the benefits of requiring operators to use a tank measurement system (i.e., auto gauge) to measure liquid levels in new storage tanks. These four improvements will secure additional reductions of harmful volatile organic compounds, methane and air toxics from oil and gas sources in New Mexico.

Background

Q: What materials have you reviewed to prepare your testimony?

A: In preparation, I reviewed:

- New Mexico Environment Department's ("NMED's") Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021)
- EDF's proposed revisions to NMED's Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021), EDF Ex. A.
- Colorado Air Quality Control Commission rule, 5 C.C.R., 1001-9, D. Ex. V.
- Pneumatic Controller Task Force Report to the Air Quality Control Commission, Colorado Air Pollution Control Division ("AQCC"), (June 1, 2020). Ex. LL.
- Economic Impact Analysis (Final Analysis) for Regulation 7 (Nov. 5, 2019). Ex. NN.

- California Air Resources Board, Standards for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Section 95668(e)(2). Ex. OO.
- Ohio General Permit.18.1, C.1.(d)(3)(b). Ex. PP.
- Analysis of OOOOa Annual Air Emission Reports, MJB&A (Dec. 11, 2018). Ex. AA.
- Cost-Benefit Analysis, Regulation 7, CDPHE (Sept. 4, 2020). Ex. CC.

Overview of NMED Rule

Q: What is your overall impression of NMED's proposed rule?

A: NMED's proposed rule is very comprehensive in nature (a broad variety of practices and equipment are addressed) and will lead to the elimination of many unnecessary emissions from machinery, equipment and processes at a reasonable cost to operators. In many cases, there will be measurable payouts, but in those cases where payout is difficult to define or may not occur, implementing practices that reduce emissions is simply the right thing to do. The absence of a direct, easily measured economic benefit should not be justification to oppose the adoption of practices that clearly enhance safety and health and protect the environment. Indeed, in many cases there are benefits (e.g., public health, environmental health, social license to operate) outside of the immediately measurable economics for the oil and gas operator.

EDF's Proposal to Include Gas Powered Pneumatic Controllers in LDAR

Q: Can you summarize EDF's proposal to include gas-powered pneumatic controllers in the instrument-based leak detection and repair (LDAR) inspections contained in proposed NMAC 20.2.50.116(C)(3) and (D)?

A: EDF proposes operators inspect gas-powered pneumatic controllers located at wellhead sites, tank battery facilities, gathering and boosting sites, gas processing plants and transmission stations when conducting required EPS method 21 or optical gas imaging inspections in order to identify leaks from improperly operating pneumatic controllers.

Q: Are instrument-based inspections necessary to identify leaks from improperly operating controllers?

A: Yes. Instruments such as OGI cameras and Method 21 devices can reliably detect excess/abnormal emissions from malfunctioning gas-powered pneumatic controllers. NMED's proposal requires operators inspect gas-powered pneumatic controllers for leaks using audio-visual -olfactory (AVO) inspections, but not using instruments. While AVO inspections are better than nothing, instrument assisted inspections are more effective than AVO.

Q: Please describe your experience with LDAR programs that looked for leaks from gas-powered pneumatic controllers.

A: When I was at Southwestern Energy (SWN) the company developed a leak detection program that included gas-powered pneumatic devices. Specifically, during the development of the Fayetteville Shale in Arkansas, SWN took great measures to eliminate leakage, flaring and venting from a variety of what was originally viewed as routine sources, processes and procedures. In fact, we pioneered the notion AND practice of green completions. With respect

to reducing leaks from improperly operating or aging equipment like pneumatic controllers SWN began by studying how much gas is potentially lost from production face (i.e., the perforated well bore interval) to the burner tip. This was borne out of a discussion in the public sphere regarding whether natural gas was as “dirty” or “dirtier” than coal. SWN engaged a research group to help and found that if methane leaked above a certain percentage of production, then the claim could well be true. At SWN we identified that point to be approximately 1% and developed what we initially called the 1% solution which eventually became 1 Future. Armed with this information and a goal to get methane loss below 1% from the production face to burner tip, we sought to identify any and all avenues where leakage occurred. We had discussions with midstream (for the Fayetteville Shale we owned and operated that) and downstream (folks like Kinder-Morgan were involved) and set out to do our part. We purchased 6 OGI cameras ($100,000 each) and set up a protocol for identifying and fixing leaks at all SWN operated wells and installations. It was very successful. Our overall expenditures were perhaps in the $1,500,000 range with 5 to 6 dedicated individuals doing the work over a two-year period. We learned a lot about trends, at least in our area of operations, which helped us preclude even having leaks in many cases. In the end we achieved approximately a 0.2% or below emission rate for CH4.

Our LDAR program helped SWN identify useful information and trends that led to emissions reductions. In particular, we discovered that equipment such as certain gas-powered pneumatic controllers, liquid level controllers and certain liquid unloading procedures fail due to specific reasons. By inspecting our equipment such as gas-powered controllers with OGI cameras we were able to detect and repair leaks, which helped us reduce methane emissions. In

addition, we optimized our operations as we discovered trends that helped us prevent leaks in the future. We developed preventative maintenance procedures that specifically addressed our locations and operations. While each individual installation may not account for a great deal of lost methane, our well count added up to a significant volume. We converted to all low or zero bleed pneumatics. There will be a number of pieces to the pie, such as on the ground LDAR and over flights, process and procedure, equipment and culture. Culture may actually be the most important. Furthermore, on new installations, one can and should incorporate the best available technology and processes into the well design and operation.

In sum, SWN's program demonstrated that leak detection and repair can help identify emissions from malfunctioning equipment including, but not limited to, gas-powered pneumatic controllers.

Q: Are you familiar with other states that have implemented an LDAR program that applies to gas-powered pneumatic controllers?

A: Yes. In preparing my testimony I reviewed Colorado's Pneumatic Controller Inspection and Enhanced Response rule that requires operators inspect for malfunctioning gas-powered pneumatic controllers using an approved instrument monitoring method when conducting LDAR inspections. Ex. LL. I see the Colorado rule as a good example for New Mexico to follow since in my experience inspections of gas-powered pneumatic controllers generates good data on operational practices and reduces emissions.

Q: Did you review the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission ("AQCC")?

A: Yes. I reviewed the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission ("AQCC"). Ex. LL. This report contains helpful information that explains why Colorado adopted its pneumatic controller inspection program for sources located in the Denver Metropolitan Ozone Nonattainment Area initially in 2017 and why it chose to expand the program statewide in 2019. In discussing the initial adoption of the rule in 2017, the report notes that "the AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers." Ex. LL, p. 1.

At the time the AQCC adopted the rule for sources in the Denver Metropolitan Ozone Nonattainment Area it also adopted a reassessment provision. A task force, consisting of representatives from industry, non-governmental environmental organizations and local governments, convened and set out to collect data on the efficacy of the program. Specifically, nine operators of well production facilities and compressor stations in the Denver Julesburg Basin collected data on their inspections of gas-powered pneumatic controllers. All inspections were conducted using OGI. Ex. LL, p. 8. Operators inspected over 3,800 pneumatic controllers. They found that 5% were improperly operating. Ex. LL, p. 11. Of these continuous bleed pneumatic controllers were found to have an improper operation rate of 3.5% while intermittent controllers had a rate of 5.6%. Ex. LL, p. 12. The study revealed a number of reasons for improper operation including corrosion, seal failure and diaphragm failure. Ex. LL, p. 13.

Operators were able to repair 26% of the improperly operating controllers on the spot. Many were made a day later, with an average lag time of 4 days later. The report concluded that:

- an OGI camera can identify improperly operating natural gas-driven pneumatic controllers
- the use of an OGI camera is particularly effective in identifying excess emissions from intermittent PCs
- where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Ex. LL.

Based on the information in the PTFR, the Task Force recommended the AQCC expand the program statewide in 2019. Ex. LL, p. 4.

Q: Do you agree with the findings of the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission ("AQCC")?

A: Yes. My experience at SWN confirms the findings in the Pneumatic Controller Task Force Report. Specifically, I agree with the conclusions of the report that:

- an OGI camera can identify improperly operating natural gas-driven pneumatic controllers
- the use of an IR camera is particularly effective in identifying excess emissions from intermittent pneumatic controllers where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven pneumatic controllers to the inspections adds minimal incremental inspection costs.

Q: Did you review additional documents supporting the Colorado pneumatic controller inspection requirement?

A: I also reviewed the Colorado Economic Impact Analysis (EIA) that accompanied the expansion of the find and fix requirement statewide in 2019. I agree with the Colorado Air Pollution Control Division (APCD) that "the inspection and recordkeeping costs are likely minimal" since operators will incorporate pneumatic controllers into their LDAR programs. Ex. NN, p. 29. The Colorado APCD estimated that costs for returning an improperly operating controller to normal operation would range from "insignificant to $600 per facility per year." This is a reasonable estimate in my opinion and well worth the investment in resource capture, safety, health and the environment.

Q: Are you aware of other jurisdictions that require inspections of gas powered pneumatic controllers?

A: Yes. In addition to Colorado, California, Ex. OO and Ohio, Ex. PP require operators inspect gas-powered pneumatic controllers when conducting LDAR. Specifically California requires operators inspect gas-powered continuous and intermittent controllers. Ohio requires operators inspect intermittent controllers when conducting LDAR. These other state requirements demonstrate the reasonableness and feasibility of EDF's proposal.

EDF's Proximity Based LDAR Proposal

Q: Do you support EDF's proposal to require more frequent inspections at well sites located near people's homes, schools, outdoor venues and workplaces?

A: Yes. SWN's experience with LDAR demonstrates that inspections help to reduce emissions. EDF's proposal requiring more frequent inspections of well sites located near homes, schools and playgrounds and other public places will help reduce emissions at those well sites. I have reviewed EDF's cost effectiveness analysis in support of its proximity based LDAR proposal and I believe the costs associated with its proposal are reasonable.

Flowback Vessels

Q: Please summarize EDF's flowback proposal and provide a brief overview of the completions process.

A: EDF has proposed NMED require operators use vapor tight flowback vessels equipped with control devices to reduce venting during flowback. Before diving into the proposal, a quick primer on completions may be helpful.

After drilling is complete and casing set and cemented, the completion process begins. There are a number of preparatory steps that are not germane to this discussion, so I will begin with the hydraulic stimulation.

Most wells require some sort of reservoir stimulation to produce at attractive economic rates. This often involves the injection of fluids and sand at high rates and pressures to cause complex fractures to be created in the near wellbore region. The overall objective and result is to

greatly increase the area open to flow and keep that area reasonably open (hence the use of sand or proppant) throughout the productive life of the well. Once that injection process is complete, the flow is reversed in order to evacuate the region of as much fluid as possible and have the created fracture close onto the introduced proppant. This phase is termed "flowback." The initial flowback is often at high and variable rates and pressures but soon settles into a more predictable and declining rate and pressure regime. The phase of more predictable rates and pressures is what we term the separation phase. In this phase, given the more stable and predictable rates and pressures, equipment can be used to collect and process the fluids and gases coming from the well into saleable products.

Following stimulation (and drill-out of plugs if required) operators are able to safely route flowback fluids to enclosed, controlled flowback vessels provided such vessels have pressure relief systems to accommodate any safety issues presented by significant changes in pressure or flow rates. It is feasible and important to route any emissions from a pressure relief system to a flare equipped with an auto-igniter or continuous pilot light to minimize venting and emissions during completions.

Q: Do other states require operators control emissions during flowback as EDF proposes?

A: Yes. EDF's proposal is modeled on a rule adopted by the Colorado Air Quality Control Commission in 2020. Ex V.

Q: Do you believe EDF's proposal is economically practicable and technically feasible?

A: Yes. I have reviewed EDF's proposal, EDF's analysis of the costs and benefits of its proposal, the Colorado AQCC rule which EDF's proposal is modeled on, and Colorado's Economic Impact Analysis for its rule, Exs. A, AA, EE, and in my opinion, EDF's proposal is economically practicable and technically feasible. First, I agree with the Colorado AQCC finding that vapor-tight flowback tanks are "manufactured, available, and technically feasible for flowback operations." Ex. EE, p. 23. I also agree that steel piping used "to connect all the active flowback vessels to a common manifold for routing vapors to" control devices and liquid knockout vessels are "widely available and technically feasible to install and operate." Ex. EE. Colorado assumed that operators would use temporary flowback tanks. Ex. EE. I agree this is a reasonable assumption. Notably, as Colorado acknowledged, if operators use permanent storage tanks to collect flowback fluids, they will save costs since they will not need to rent temporary flowback vessels.

I have reviewed the Colorado EIA for its proposal and I agree with Colorado's conclusion that its rule is cost effective. To estimate the costs of its rule Colorado assumed that operators require 10 to 15 500 bbl flowback vessels at a multi-well production facility with 10 wells. Colorado estimated the cost of each new storage vessel to be $30,500. Costs for used tanks, they estimated, at $19,500 to $7,000. Colorado assumed a one-time capital cost of $500 for steel piping, a one-time cost of $500 to install the steel piping, and operation and maintenance costs of $500. Colorado assumed a 15-year lifetime for this equipment. Colorado accordingly concluded that the annualized cost per flowback tank would be $4,830. Assuming an average of 12 flowback tanks, this equates to an annualized cost of $57,958 per well site.

This is a "worst-case cost effectiveness estimate" because it assumed an operator would use the 12 flowback tanks only once, at one well site. Ex. EE, p. 28. More likely operators would use the same flowback tank at multiple wells for the lifetime of the tanks. CDPHE estimated a 15-year lifetime for flowback tanks which I agree is reasonable.

Using the cost estimates contained in the Colorado EIA EDF analyzed the cost effectiveness of its initial flowback proposal using New Mexico specific completions data. I have reviewed EDF's cost effectiveness analysis and in my opinion EDF's analysis demonstrates the cost effectiveness of its proposal.

Zero Bleed Pneumatic Controllers

Q: Please summarize EDF's revisions to the pneumatic controller retrofit provision?

A: At a high level EDF has proposed to increase the number of gas-powered pneumatic controllers that must be retrofit to zero bleed devices, and shorten the timeframe in which operators must do so. EDF's proposal is modeled on a rule recently adopted by the Colorado Air Quality Control Commission, which I reviewed in preparing my testimony. In my opinion, EDF's proposal is economically reasonable and practicable. Gas-powered pneumatic controllers vent methane and other pollutants to the atmosphere by design. As NMED's proposal demonstrates, technologies exist today to operate pneumatic controllers with zero venting. EDF's proposal does not require the use of any new types of technologies that could theoretically increase costs. Rather, we simply seek to require operators to retrofit more devices in a more timely manner than NMED has proposed. This is good policy, and will result in a decrease of

emissions from normally functioning pnuematic controllers as well as malfunctioning controllers.

Auto Gauging

Q: Please describe EDF's proposal to require operators use auto gauges on new storage tanks and flowback vessels.

A: EDF proposes operators install auto gauges on new storage tanks and flowback vessels to minimize emissions associated with manual tank gauging and measurement.

Q: Please describe what an automatic tank gauge is.

A: An automatic (tank) gauge is a device that automatically/continuously measures the level of crude oil, LNG and petroleum products (could be for water also) in storage tanks/vessels and raises an alarm when the level goes down or up to threshold limits. It operates electronically and can keep track of tank leakage.

Q: What are the benefits of EDF's proposal?

A: There are multiple benefits to EDF's proposal including:

- Overall safer operations: avoiding the need for workers to open hatches thus exposing them to fumes; eliminating the possible needs for work at heights; reducing the possibilities of ignition/fires/explosions due to the combination of fumes, oxygen and any type of ignition source.
- Operational efficiency: more accurately and timely measurements; easier planning of liquid removal; can run centralized inventory control and disposition; less likelihood of

needing temporary flow interruption; less labor intensive; eliminates sources of operator errors such as leaving thief hatches open.

- Environmental and health advantages: reduce likelihood of spills; reduce pollution from emissions and spills; protect public from poor air quality; protects waterways from spill pollution; less likely to have disastrous impacts from fires and explosions.

Q: Have you reviewed Colorado's Economic Impact Analysis for its tank measurement requirement, and if so, please state your opinion of the analysis.

A: Yes, I have reviewed the Colorado EIA for its tank measurement requirement. In my opinion, the costs estimated are reasonable and appropriate and support NMED including a similar requirement in its rule.