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Submission in Response to
New Mexico Environment Department
Draft Version of Ozone Precursor Rules

New Technologies of Alternative Equipment Leak Monitoring

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1. Introduction

This note is responsive to New Mexico Environment Department's call for comments on the draft version of ozone precursor rules. In particular, we provide feedback on point 3 of NMED's requested feedback list. These comments relate to the potential for new leak detection technology to reduce emissions more effectively at low cost than can be achieved with traditional programs. We also discuss the potential for new evaluation techniques to demonstrate the performance of these technologies.

2. Technology developed for methane emission detection can make VOC leak detection and repair more efficient and effective

In the production and processing sector of the New Mexico oil and gas industry, emissions of natural gas include emissions of both methane and VOC. New Mexico gas production originates from three sources: (1) natural gas, from wells drilled for gas production; (2) associated gas, from wells drilled primarily for oil production; and (3) coal bed gas. These production streams have different amounts of VOC. In terms of molar (volumetric) composition the VOC fractions are 3%, 6%, and 1% respectively.[1] For that reason, standards that reduce the emissions of either gas may reduce emissions of the other gas as a co-benefit. However, there are significant differences in the properties of those gases that can impact how emissions of those gases are detected.

There are only two oilfield leak detection technologies currently approved by the U.S. Environmental Protection Agency, Method 21 and optical gas imaging. These are also the only two technologies listed in 20.2.50.16.C.2.b NMAC. One of the two approved gas leak detection methods is Method 21,[2] in which a probe samples the air at the surfaces of pipe fittings, valves, and other components. The second approved method is optical gas imaging (OGI), an Alternative Work Practice.[3] OGI images gas plumes, enabling leak detection more efficiently and more effectively than Method 21 sniffer probes. Optical gas imagers utilize broadband infrared (IR) spectroscopy, which is suitable for short range (distance $\approx$ 4 meter) inspection[4]. Most commonly, OGI instruments used in the oil and gas industry (e.g. FLIR GF320)[5] are sensitive to wavelengths in the mid-IR band between 3.2 μm and 3.4 μm. In this band, OGI is sensitive to both methane and VOC (such as propane), see Figure 1.

Thus, given presently approved methods as commonly implemented, relying solely on a VOC emission rule is equivalent to relying on a methane emission rule, so long as those methods are used to inspect all infrastructure, regardless of the VOC content of natural gas produced in the region.

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[1]San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report, Ramboll Environ, November 2016, Table 3.2
https://www.wrapair2.org/pdf/2016-11y_Final%20GSJB-Permian%20EI%20Inputs%20Report%20(11-09).pdf

[2] 40 CFR 60 Appendix A-7

[3] 73 FR 78199-78219

[4] A.R. Brandt, Assessment of LDAR technology options, ONE Future Methane & Climate Strategies Event, 15 May 2018. http://onefuture.us/wp-content/uploads/2018/05/Stanford_Brandt_LDAR_2018.pdf

[5] FLIR, Infrared Camera for Methane and VOC Detection, https://www.flir.com/products/gf320/

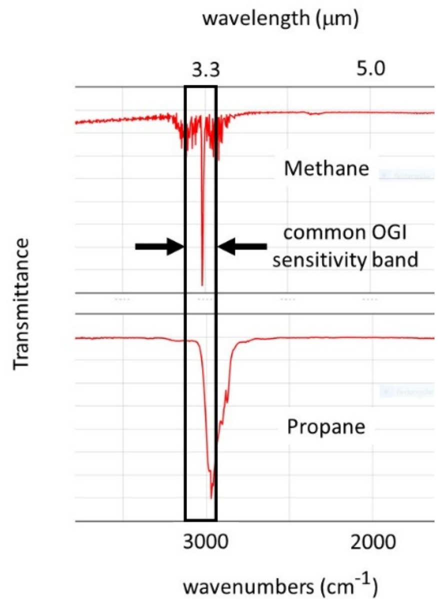

Figure 1. Infrared transmittance spectra of methane (top) and propane (bottom).[6] Optical gas imagers are typically sensitive to wavelengths between 3.2 µm and 3.4 µm (black box), thereby imaging both methane and VOC.

However novel technologies to detect fugitive emissions are being developed by numerous innovators and field tested by a broad coalition of operators, industry trade groups, and environmental advocates. Advanced technologies can be usefully deployed to reduce, perhaps dramatically, the cost of compliance with natural gas leak detection and repair (LDAR) rules[7,8]. These technologies potentially include surveillance of oil and gas infrastructure by sensors deployed on drones, helicopters, fixed-wing aircraft, and/or earth-orbiting satellites[9,10,11,12]. For many emerging technologies, speciation of fugitive emissions is inherent to the physical principles that underly the detection technique.

The principle that underlies many emerging technologies is the absorption of infrared radiation, commonly referred to as IR spectroscopy. Methane and VOC are both strong absorbers of infrared radiation. Indeed, their strong infrared absorption is the reason that these compounds are potent greenhouse gases.

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[6] NIST, 2019. NIST Chemistry WebBook, National Institute of Standards and Technology. https://webbook.nist.gov Accessed 8 September 2019.

[7] American Petroleum Institute, EPA-HQ-OAR-2017-0483-0801 https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0801

[8] Independent Petroleum Association of America, EPA-HQ-OAR-2017-0483-1006 https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-1006

[9] Kairos Aerospace, http://kairosaerospace.com/

[10] Ball Aerospace, Methane Monitor http://www.ball.com/aerospace/Aerospace/media/Aerospace/Downloads/D3242-Methane-Monitor_0518.pdf?ext=.pdf

[11] Bridger Photonics, Gas Mapping LIDAR, https://www.bridgerphotonics.com/gas-mapping-lidar/

[12] GHGSat, Global Emissions Monitoring, https://www.ghgsat.com/

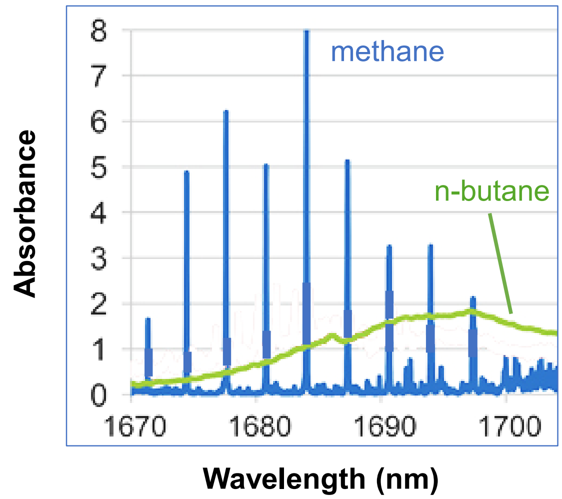

Figure 2. Methane absorbs infrared radiation in a series of narrow features, while n-butane, a typical VOC, absorbs infrared radiation in a single, wide feature.[13]

While both methane and VOC absorb infrared radiation, the ways in which they absorb infrared radiation are different; hence the ability to detect them with infrared radiation is different. The IR spectra of small molecules such as methane consist of a series of narrow spectral features, while the IR spectra of larger molecules such as VOC consist of a single broad spectral feature. As shown Figure 2, methane absorbs infrared radiation strongly at particular wavelengths but only weakly at nearby wavelengths, while n-butane (a typical component of VOC) absorbs infrared radiation at all wavelengths in a relatively broad wavelength range.

Differences in the width of the spectral features impacts how methane and VOC are detected. Some emerging methane detection technologies utilize near infrared (also called shortwave infrared) spectroscopy, with detected wavelengths around 1650 nm. The IR spectrometer is mounted on a drone, helicopter, airplane, or satellite.[14,15] Measuring emissions using an IR remote sensor requires correcting for many factors than can influence the amount of infrared radiation detected, including the strength of the infrared source (either the sun or a laser); the reflectivity of the surface that reflects the infrared radiation to the spectrometer; and scattering from dust, water, or other airborne particulates.

Using differential absorption spectroscopy, wavelength modulation spectroscopy, or similar techniques, corrections are performed by measuring the difference in infrared radiation detected at two wavelengths: one wavelength is absorbed by the gas, and the other wavelength is not absorbed by the

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[13] Mitsumoto, Laser Spectroscopic Multi-component Hydrocarbon Analyzer, Yokogawa Technical Report English Edition 56(2) (2013), https://web-material3.yokogawa.com/rd-te-r05602-008.pdf

[14] Tandy, Methane Monitor: The First Full Year of Campaigns and Lessons Learned, A43P-3361, American Geophysical Union Annual Meeting, December 2018. [Ball Aerospace]

[15] Jacob, Satellite observations of atmospheric methane and their value for quantifying methane emissions, Atmospheric Chemistry & Physics, 16, 14371–14396, 2016. www.atmos-chem-phys.net/16/14371/2016/ doi:10.5194/acp-16-14371-2016

gas. This procedure requires the two wavelengths to be close together, so the interfering factors are held constant and can be subtracted out. This requirement is met for methane, as a result of its narrow spectral features; but not for VOC, as a result of its broad spectral features. Due to this limitation, the most promising IR spectrometers deployed in remote sensing applications can reliably detect fugitive methane emissions but cannot reliably detect fugitive VOC emissions.

As a result, in order to encourage the development and deployment of emerging leak detection technologies, New Mexico should allow regulatory obligations to be met by detecting emissions of methane. This recommendation could be satisfied in a VOC standard by establishing a methane:VOC correction ratio, where emissions of methane would be measured directly and then emissions of VOC would be calculated using this ratio. This ratio would depend on the composition of the produced gas.

3. New leak detection technologies can simultaneously improve emissions reductions and reduce compliance cost compared to what is possible using traditional measurement

Numerous studies have investigated methane emissions from the US oil and gas sector, and here we emphasize two salient conclusions. First large emissions often come from small facilities. While it might be imagined that emission rates are proportional to production, evidence shows that the relationship between lost gas and beneficially produced gas is weak.[16] Figure 3 shows that wells producing 10-100 Mcf/d (Mcf/d = thousands of standard cubic feet of gas per day) constitute 40% of U.S. gas well sites, contribute only 8.7% of total gas production, but are responsible for 51% of oilfield methane emissions. Those relatively small producers account for 23% of emissions from sites emitting more than 7 kg/h, which is detectable by many airborne leak detection systems. As a result, inspection programs are more effective if they include small and large facilities, rather than focusing on large facilities alone.

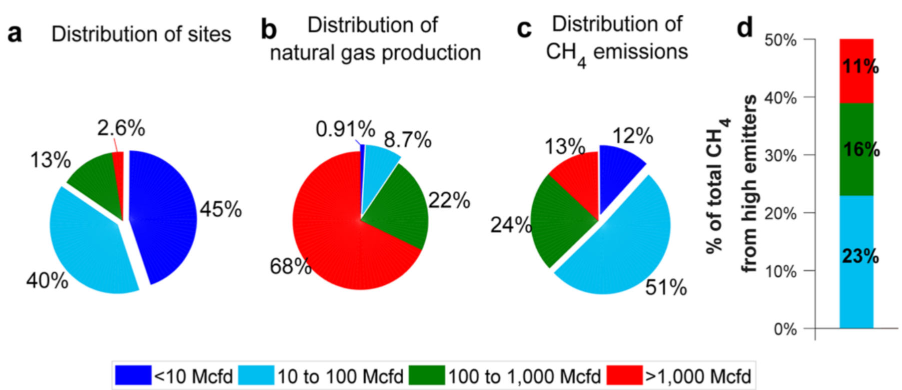
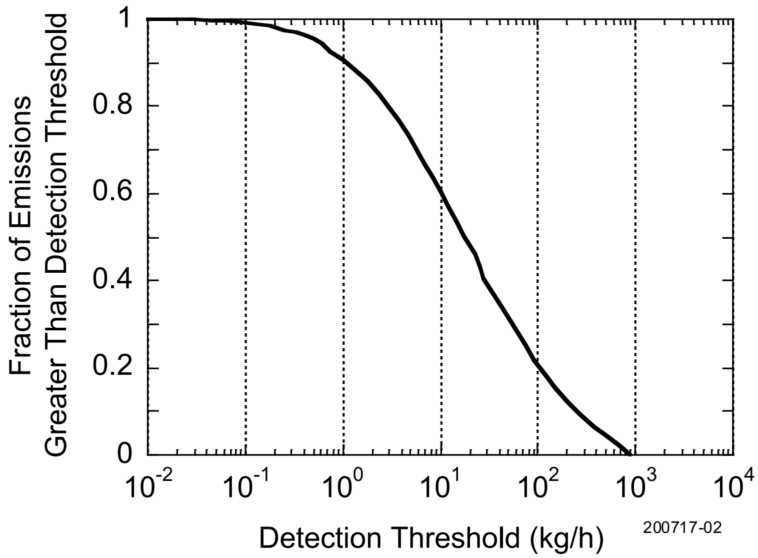


Figure 3. Emission characteristic of various groups of wells in the United States.[17]

[16] M. Omara et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, Environ. Sci. Technol. 2018, 52, 12915−12925 https://pubs.acs.org/doi/abs/10.1021/acs.est.8b03535

[17] M. Omara et al., Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate, Environ. Sci. Technol. 2018, 52, 12915−12925 https://pubs.acs.org/doi/abs/10.1021/acs.est.8b03535

Second, most emissions come from a relatively small number of sites. Zavala-Araiza et al. (Figure 4) found that the top 1% of natural gas emitting sites in the Barnett Shale production region (with emissions greater than 26 kg/h) accounted for 44% of the region's total methane emissions.[18] Moreover, only about 10% of site-level methane emissions were due to leaks smaller than 1 kg/h, a leak rate 30 times that of the EPA-mandated measurement sensitivity. As a result, inspection technologies can still be quite effective even if their sensitivity is somewhat lower than that of existing techniques.



Zavala-Araiza, Nat. Commun. 8, 14012 (2017)

Figure 4. Spectrum of site-level emissions from Barnett Shale oil and gas facilities.

Traditional inspection technologies are often considered inefficient, leading to unacceptably high costs and understandable resistance from some segments of the oil and gas industry. That inefficiency is a result of failure to optimize for the conditions described above. Both currently approved technologies involve manual inspection that is ill-suited for inspecting large numbers of facilities. Moreover the common OGI technology has a sensitivity more than an order of magnitude higher than required for effective inspection.[19] However, many new technologies are being developed to detect methane emissions, including ground sensors mounted permanently on location, handheld sensors, and mobile sensors mounted to trucks, drones, helicopters, airplanes, and satellites.[20,21] Several of these new technologies were designed recognizing that large emitters are scarce, but those large emitters are

[18] D. Zavala-Araiza et al., Super-emitters in natural gas infrastructure are caused by abnormal process conditions, Nature Communications 8, 14012 (2017). https://www.nature.com/articles/ncomms14012

[19] A.P. Ravikumar, "Good versus Good Enough?" Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera, Environmental Science & Technology, 2018, 52, 4, 2368–2374 https://pubs.acs.org/doi/10.1021/acs.est.7b04945

[20] T.A. Fox et al., A review of close-range and screening technologies for mitigating fugitive methane emissions in upstream oil and gas, Environmental Research Letters, Volume 14, Number 5 https://iopscience.iop.org/article/10.1088/1748-9326/ab0cc3

[21] A.P. Ravikumar, Single-blind inter-comparison of methane detection technologies – results from the Stanford/EDF Mobile Monitoring Challenge, Elementa, 7(1), p.37. https://www.elementascience.org/article/10.1525/elementa.373/

responsible for most of the total natural gas lost from oil and gas facilities. The new techniques scan large numbers of facilities using detectors with modest sensitivities. As a result, many new technologies can perform methane inspections at greater effectiveness and at lower cost than can be achieved using OGI. In one example, Rashid et al.[22] found an optimal routing solution for the aerial surveillance of 10,471 wells in the Permian Basin, utilizing an airborne sensor with a sensitivity of 1 kg/hr. They estimated the cost of inspection to be only $100/well, considerably less than the costs of inspection with EPA-approved technology, which is estimated by the EPA to be around $600/well.[23] Because of the high performance and low cost of emerging technology, we recommend New Mexico structure their regulation to encourage the use of new technology.

4. New evaluation methods can demonstrate equivalent emissions reductions based on the detection sensitivity and deployment frequency of emerging technology

While the low costs associated with new technology are obviously attractive, it is equally important to ensure any new technology provides environmental protection that is sufficient to meet regulatory objectives. Consistently evaluating the performance of new leak detection technology is challenging due large number and great diversity of new detection technologies. Fortunately, two new evaluation methods allow rigorous determination of the environmental protection provided by any leak detection program.

The first method determines which leaks can be detected, under representative conditions, by a new detection technology. That evaluation can be performed by controlled-release tests, in which a known amount of methane is intentionally released from a facility designed to represent a typical oil and gas facility. A series of releases of different gas compositions, at different rates, from different parts of the facility, under different environmental conditions tests the ability of a detection technology to identify leaks in a scientifically rigorous manner. This process is applicable for any leak detection technology, from a handheld detector to a satellite. Using this process, technologies have been evaluated by industry and the environmental community.[24] Most recently, a facility specifically designed for this testing has been constructed at Colorado State University using funding from the US Department of Energy.[25]

The second method is a model that evaluates the effectiveness of a leak detection program—in terms of the amount of methane emissions reductions it achieves—based on the capabilities of the leak detection technology (determined by controlled-release testing as described above) and the manner in which the technology is deployed (particularly the frequency of deployment). In general, greater reductions in fugitive methane emissions can be achieved by using a more sensitive detector, which enables detection of more leaks, or a higher frequency of inspections, which detects leaks sooner. An example of such a

[22] K. Rashid et al., Optimized inspection of upstream oil and gas methane emissions using airborne LiDAR surveillance, Applied Energy 275 (2020) 115327 https://doi.org/10.1016/j.apenergy.2020.115327

[23] EPA Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, subpart OOOOa; 2016. p. 43.

[24] http://blogs.edf.org/energyexchange/2018/03/29/why-one-oilfield-service-provider-sees-opportunity-in-managing-methane/

[25] https://energy.colostate.edu/metec/

model is the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model developed originally at Stanford University.[26]

The combination of testing and modeling allows the performance of new leak detection programs to be evaluated with unusual rigor. We recommend New Mexico structure its regulation to encourage and accelerate the deployment of leak detection programs and technologies whose effectiveness have been proven using these new evaluation tools.

5. These proposals enjoy broad support from diverse stakeholders

The new leak detection technologies and new evaluation methods described here have united diverse groups of stakeholders—including those who do not see eye to eye on other issues regarding emissions regulations—to support a novel process for determining equivalency. In this process, new detection programs should be deemed equivalent if they achieve equivalent emissions reductions, aggregated over multiple facilities. That equivalent aggregate emissions reduction should be demonstrated using the new evaluation methods. Support for this concept is provided by public reports and comments to regulators written by groups including:

- The Environmental Defense Fund (EDF), which is a leading environmental NGO with a particular focus on methane emissions from the oil and gas sector[27]
- The Independent Petroleum Association of America (IPAA), which represents primarily small and medium-sized energy businesses[28]
- The American Petroleum Institute (API), which represents primarily medium-size and large energy businesses[29]
- A group representing oil companies, oilfield service companies, technology companies innovating leak detectors, and academics, who came together to demonstrate their support for this issue[30]
- Operators, regulators, academics, solution providers, consultants, and non-profit groups from Canada and the U.S who participated in a workshop dedicated to this issue.[31]

As demonstrated in those public reports and comments, stakeholders representing diverse viewpoints on many issues related to emissions regulation agree on this singular issue of how to demonstrate equivalency of alternative leak monitoring plans. Given the broad support on this issue, we recommend New Mexico adopt regulations incorporating the recommendations of these groups, potentially including the specific language listed below.

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[26] http://arvindravikumar.com/feast/
https://pubs.acs.org/doi/abs/10.1021/acs.est.5b06068
https://pubs.acs.org/doi/abs/10.1021/acs.est.7b04945
[27] https://www.edf.org/climate/cutting-methane-emissions-regulatory-innovation
[28] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-1006
[29] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0801
[30] https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-1280
[31] https://www.elementascience.org/article/10.1525/elementa.369/

6. Specific regulatory language regarding criteria necessary to demonstrate equivalency of alternative equipment leak monitoring plans in Section 20.2.50.16(C) NMAC

For the reasons specific above, we suggest New Mexico adopt the following regulatory language regarding criteria necessary to demonstrate equivalency of alternative equipment leak monitoring plans. The language used here was inspired by the language of the relevant portion of the EPA's OOOOa regulation.

(a) Determination of equivalency of alternative equipment leak monitoring plans will be evaluated by the following guidelines:

(1) The applicant must provide information that is sufficient for demonstrating the alternative equipment leak monitoring plan achieves at least as equivalent reduction in aggregate emissions across the range of equipment and geographic boundaries, as defined in the application, as the relevant standards would achieve. Such a demonstration could rely upon controlled test data, field test data, modeling, other information or any combination thereof. The application must include the following information:

(i) Details of and/or typical anticipated equipment that would be monitored by the alternative program and the geographic boundaries for which the alternative will apply.

(ii) A description of the monitoring method including monitoring technology(ies), monitoring method(s) including frequency(ies), and commensurate operational responses to data derived from the monitoring.

(iii) A description of the procedures and controlled testing and/or field testing sites used to collect the data.

(iv) A description of the modeling procedure, if any.

(v) Results from the controlled test, field tests, models, and other methods demonstrating that the alternative equipment leak monitoring plan achieves at least as equivalent reduction in aggregate emissions across the range of equipment and geographic boundaries as the relevant standards would achieve.

(b) Once approved, the alternative equipment leak monitoring plan may be employed on similar equipment, sites and facilities in the geographic region upon which equivalency was demonstrated.

7. Qualifications of the Commenters

Dr. Robert L. Kleinberg retired in 2018 after a forty-year career in the oil and gas industry, having worked at both an operating company – Exxon – and at an oilfield services company – Schlumberger. His professional record is reflected in more than 120 scientific and technical publications and 41 U.S. patents. He has been elected to the National Academy of Engineering.

Dr. Andrew E. Pomerantz is an Energy Transition Technology Advisor at Schlumberger. He joined the company in 2005, and his roles have included technical and management positions developing new methods to characterize oil and gas reservoirs and to reduce the GHG footprint of oil and gas development. He has authored 100 peer-reviewed technical papers and 25 granted U.S. patents. He currently serves as an Associate Editor for scientific and professional journals including *Energy & Fuels*, published by the American Chemical Society.

The opinions expressed herein are those of the authors, and do not necessarily represent the views of the institutions with which they are affiliated.