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RETURN RECEIPT REQUESTED

November 23, 2010

Lisa Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Bldg.
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

Re: Opportunities to Reduce Methane Emissions from Oil and Gas Operations through the New Source Performance Standards, EPA-HQ-OAR-2010-0505-0001

Dear Administrator Jackson:

Enclosed please find an expert report detailing the tremendous opportunities to reduce methane emissions from the oil and gas sector under the Clean Air Act. The U.S. Environmental Protection Agency ("EPA") is currently reviewing whether to update the New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAP"), and whether to promulgate residual risk standards for the oil and gas sector. *See* Docket EPA-HQ-OAR-2010-0505-0001. It is our hope that this report can guide the Agency as it completes its review and proposes future action, particularly with regards to the NSPS.

The report, which was prepared by Cindy Copeland and Megan Williams[1] for Earthjustice on behalf of WildEarth Guardians and San Juan Citizens Alliance, provides a critical roadmap for achieving at least a 90% reduction in methane, if not greater, from oil and gas operations nationwide using demonstrated practices and technologies. Such reductions promise a number of benefits: reduced greenhouse gas emissions, increased savings for industry, decreased safety risks, and a number co-benefits, including reductions in air toxics, ozone precursors, and greater overall protection for public health and welfare. Above all, these reductions would just make good business sense. They would encourage greater efficiency, reward those companies that have already mobilized methane reduction practices and technologies, and fuel the creation of jobs within the air pollution control sector. The benefits cannot be overstated. A 90% reduction in methane emissions from the oil and gas sector has the potential to recover **more than $1 billion in lost value every year.**

We urge you to take into consideration the findings of this report and to seize this opportunity to achieve significant, sector-wide reductions in methane through the NSPS. Specifically, we urge you to set concrete limits on methane emissions based on the available control technologies and

[1] *See* CVs for Ms. Copeland and Ms. Williams, attached.

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practices outlined in the enclosed report. We further urge you to set a nationwide goal of reducing methane emissions by 90% or more from the oil and gas sector. The EPA's duty and authority to establish such standards and goals is firmly supported by the Clean Air Act.

As you know, the Administrator has a duty to address the issue of methane emissions through the NSPS. It is already recognized that the oil and gas source category releases air pollution anticipated to endanger public health and welfare. Furthermore, the EPA has definitively found that greenhouse gases, including methane, pose an endangerment to public health and welfare. *See* 74 Fed. Reg. 66496 (Dec. 15, 2009). In light of these facts, the Administrator has clear authority to promulgate "a standard for emissions of [methane] which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which ... the Administrator determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1).

The Administrator also has a duty to regulate methane emissions from existing sources in accordance with Section 111(d) of the Clean Air Act. *See* 42 U.S.C. §§ 7411(d)(1)(A)(i) and (ii); 40 C.F.R. § 60.21(a). Therefore, we urge the Administrator to ensure that existing sources of methane are addressed as appropriate under Section 111(d).

We appreciate your attention to this issue and your commitment to comprehensively reviewing the opportunities available for controlling harmful air pollution from the oil and gas sector. It is fortunate that there exists a wealth of proven options to cost-effectively control emissions. We urge you to ensure that any revised NSPS ensure concrete reductions in methane consistent with what we know works. If you or your staff have any questions about this report, please contact me at 303-996-9622. Thank you.

Sincerely,

Edward B. Zukoski, Staff Attorney

Attorney for WildEarth Guardians and San Juan Citizens Alliance

Cc: Gina McCarthy, Deputy Administrator for Air and Radiation
Bruce Moore, Senior Technical Advisor, Oil and Natural Gas Sector, Office of Air Quality Planning and Standards

Encs. (1) Report; (2) Cindy Copeland CV; and (3) Megan Williams CV.

METHANE CONTROLS
FOR THE OIL AND GAS PRODUCTION SECTOR

prepared by Megan Williams and Cindy Copeland

November 23, 2010

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Due to rapidly increasing and widespread oil and gas development across the country and due to the extraordinarily high levels of greenhouse gases and air pollutants emitted from this development, there is an urgent need for strong protective standards to be established for the oil and natural gas sector.

Oil and natural gas production are included in the EPA's priority list of categories set forth at 40 CFR § 60.16, pursuant to section 111(b)(1)(A) of the Clean Air Act, which in the Administrator's judgment, cause or contribute "significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[1] On June 24, 1985, EPA promulgated New Source Performance Standards (NSPS) for Equipment Leaks of volatile organic compounds (VOCs) from Onshore Natural Gas Processing Plants (40 CFR part 60, subpart KKK) and on October 1, 1985, EPA promulgated a NSPS for SO_2 emissions from Onshore Natural Gas Processing (40 CFR part 60, subpart LLL). EPA has failed to promulgate more comprehensive standards for the much broader source category of oil and natural gas production (including both onshore and offshore development) and has failed to update, as required by law, the two standards it did promulgate. In response to a January 14, 2009 lawsuit brought by WildEarth Guardians and San Juan Citizens Alliance, EPA agreed to a consent decree whereby it would review and propose necessary revisions and expansions to the NSPS for the oil and natural gas production sector by January 31, 2011, and finalize standards by November 30, 2011.[2]

A critical component of EPA's review and revision of the NSPSs for oil and gas operations is the development of standards for the reduction of methane emissions from the oil and gas sector. Methane is a potent greenhouse gas, roughly 20 times more powerful at warming the atmosphere than carbon dioxide by weight, and with a relatively short atmospheric lifetime of about 12 years. Methane, thus, is a prime contributor to short-term climate change over the next few decades.

There are many proven technologies and practices already available to reduce significantly the methane emissions from oil and gas operations. These technologies also offer opportunities for significant cost-savings from recovered methane gas. Methane is often expressly exempt from state regulations since greenhouse gases (GHGs) are not yet federally regulated as an air pollutant. EPA must fill this void by proposing comprehensive regulations for methane. EPA's inclusion of methane performance standards and operating practices for oil and gas would be a

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[1] 42 U.S.C. § 7411(b)(1)(A).

[2] See Consent Decree, WildEarth Guardians v. Jackson, 1:09-cv-00089-CKK (D.D.C), Dkt. Entry # 25 (Feb. 4, 2010).

cornerstone in a comprehensive regulatory framework for methane emissions reductions across the U.S.

We respectfully urge EPA to expeditiously develop and apply New Source Performance Standards for new and modified oil and gas sources that achieve at least a 90% reduction in methane emissions. EPA's own voluntary Natural Gas STAR program provides an excellent opportunity to build from the wealth of knowledge and information regarding methane reduction control technologies for every component of the oil and gas sector. Based on the demonstrated effectiveness of many of these key control technologies, EPA should require at least 90% reduction in methane emissions from sources among this sector, and in some cases reductions greater than 90% are warranted. A framework to achieve at least a 90% reduction in methane emissions from oil and gas sources is laid out in this report.

As the oil and gas sector continues to grow, more sources of methane emissions are added each year. These new emissions sources include a certain percentage that replace existing sources (*e.g.*, new compressor engines that replace old ones) and a certain percentage that add to the total population. Progress in reducing emissions through standards for new and modified sources depends on the rate at which new emissions sources are added to the population and on the level of reductions implemented. The higher the level of control required, the sooner meaningful emissions reductions will be achieved. A 90% sector-wide reduction in emissions might still take years to achieve depending on how quickly new sources penetrate the source population. Therefore, it is imperative that EPA establish the highest level of emissions reductions possible for new and modified sources in the oil and gas sector.

There are numerous existing control technologies for oil and gas emission sources that achieve a 90% or greater control efficiency for reducing methane emissions. For example, compressor rod-packing technologies can reduce methane emissions by more than 90%, the use of no bleed pneumatic devices can practically eliminate methane emissions, the use of dry seals in centrifugal compressors can reduce methane emissions by 99%, zero emission dehydrators virtually eliminate methane emissions, and the use of vapor recovery units at crude oil and condensate storage tanks can reduce methane emissions by at least 98%. In addition, there are multiple examples of existing emissions reduction programs at the state, county, and international levels that require methane emissions reductions of 90% or greater from oil and gas sources.

The following is a listing of the methane control technologies and measures recommended in this report. These controls were chosen because they would achieve the maximum emission reductions possible using available technologies or practices. The recommendations are listed by major oil and gas source type.

Recommended methane controls for pneumatic devices:

- Require Pneumatic Devices That Use Instrument Air or Mechanical Controls, Nitrogen Gas, or Electric Valve Controllers in Place of Gas Powered Pneumatic Devices
- Require Low-Bleed Pneumatic Devices for New Installations and Require Modified Sources to Retrofit High-Bleed Devices with Low-Bleed Devices

Recommended methane controls for compressors:

- Require the Use of State-of-the-Art Compressor Rod-Packing Technology
- Require the Use of Dry Seals in Centrifugal Compressors
- Require the Use of Air or Electric Starters Instead of Gas Starters
- Require the Use of State-of-the-Art Compressor Cylinder Unloader Technology and Require Regular Replacement
- Require Operating Practices That Eliminate or Reroute Gas Leakage When Taking Compressors Off-line
- Require Direct Inspection and Maintenance at Compressor Stations
- Require Isolation Valves To Be Installed in Close Proximity to Compressors For All New Installations

Recommended methane controls for dehydrators:

- Require the Use of Zero Emission Dehydrators
- Require the Use of Solid Desiccant Dehydrators in Cases Where Zero Emission Dehydrators Are Not Feasible
- Require Glycol Dehydrators to Use Vapor Recovery Units
- Require the Use of Flash Tank Separators
- Require Circulation Rate Adjustment Practices for All Glycol Pumps
- Require Glycol Dehydrators to Use Portable Desiccant Dehydrators During Maintenance
- Require Installation of BASO® Valves

Recommended methane controls for tanks:

- Require the Use of Vapor Recovery Units With at least 98% Control Efficiency for All New Crude Oil and Condensate Storage Tanks

Recommended methane controls for wells:

- Require the Use of Reduced Emissions Completions or Green Completions
- Require the Installation of Plunger Lift Systems and the Development of Operational Practices that Minimize Methane Emissions
- Require the Installation of Downhole Separator Pumps, Where Applicable
- Require Mud Degassing Vents Be Routed to a Vapor Recovery Unit

Recommended methane controls for pipelines:

- Require the Use of Gas Main Flexible Liners and State-of-the-Art Pipeline Material and Protective Coatings
- Require Maintenance Practices for Pipelines
- Require the Installation of Excess Flow Valves on All Gas Service Lines

Recommended methane controls for flares:

- EPA should require producers to reduce emissions by instituting a gas utilization program, such as sending emissions to a vapor recovery unit, rather than flaring and venting.

Recommended methane controls for directed inspection and maintenance practices:

- EPA should require that operators implement directed inspection and maintenance programs and good work practices in all possible sectors in order to detect and reduce methane emissions.

There is a large body of scientific work documenting the adverse impacts to public health and welfare from climate change caused by GHG emissions, such as methane. More recently, scientific studies have also demonstrated that these same methane emissions contribute to the formation of ground-level ozone, a harmful air pollutant that impacts the health of millions of Americans.[3] Specifically, the U.S. Climate Change Science Program recently reported that methane reductions accomplish the dual goal of addressing climate change and ozone pollution.[4] Methane reductions achieved through new source performance standards and practices will have a direct impact on both climate change and ozone pollution.

Many of the methane emission controls for the oil and gas sector also reduce VOCs and hazardous air pollutants (HAPs), while some controls also have the added benefit of improving safety at the sources. State, local and international programs that aim to reduce VOCs and HAPs and are reviewed in this report because of the co-benefit any such reductions would have for reducing methane emissions. Any strategy to limit the amount of VOC or HAP emissions from oil and gas processes would also reduce methane emissions. And conversely, regulatory reductions in methane emissions will also reduce VOC and HAP emissions. The associated air quality benefits that result from reductions in VOC and HAP emissions are a huge co-benefit of methane reduction technologies.

VOCs are an important component in the formation of ozone. Ozone pollution causes breathing problems, chest pain and even permanent lung damage after repeated exposure. Oil and gas sources are major contributors to ozone problems in areas of highly concentrated development, such as western Wyoming, where sparsely populated Sublette County is a proposed ozone nonattainment area.[5] Most of the VOCs emitted from oil and gas sources are also hazardous air pollutants. HAPs present in oil and gas development include benzene, toluene, ethylbenzene, xylene and n-hexane, which cause a wide array of adverse health impacts, including cancer and other serious illnesses.[6]

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[3] *See, e.g.*, Arlene M. Fiore *et al.*, "Characterizing the Tropospheric Ozone Response to Methane Emission Controls and the Benefits to Climate and Air Quality," Journal of Geophysical Research Vol. 113, April 30, 2008, p.1 ("[I]n the presence of nitrogen oxides (NO_x), tropospheric CH4 [methane] oxidation leads to the formation of O_3 [ozone].")

[4] *See* Hiram Levy II *et al.*, U.S. Climate Change Science Program Synthesis and Assessment Product 3.2, "Climate Projections Based on Emissions Scenarios for Long-Lived and Short-Lived Radiatively Active Gases and Aerosols", September 2008, p. 65, http://www.climatescience.gov/Library/sap/sap3-2/final-report/ (finding that reducing methane emissions "lead[s] to reduced levels of atmospheric ozone, thereby improving air quality" and "lead[s] to reduced global warming").

[5] See Wyoming Department of Environmental Quality at http://deq.state.wy.us/aqd/Ozone%20Nonattainment%20Information.asp

[6] see EPA, http://www.epa.gov/airquality/oilandgas/basic.html

California's Proposed Greenhouse Gas Reduction Plan is an Example of a Comprehensive Mandatory Approach to Greenhouse Gas Reductions

California is currently working to require GHG emissions reductions in a broad sweeping plan. In 2011, the California Air Resources Board (CARB) will consider a historic proposal to limit GHG emissions from every sector in the state. If approved, this measure will be implemented in 2012.[7] CARB's Climate Change Scoping Plan aims to achieve greenhouse gas reductions in oil and gas extraction and transmission. These strategies will use proven technologies from EPA's Natural Gas STAR program, but the program will be mandatory rather than voluntary. The control measures for the oil and gas extraction sector will include "improving operating practices to reduce emissions when compressors are taken off-line; installing compressor rod packing systems; substituting high bleed with low bleed pneumatic devices; improving leak detection; installing electronic flare ignition devices; replacing older equipment (flanges, valves, and fittings); and installing vapor recovery devices." The GHG control technologies for the oil and gas transmission sector will include "improving operating practices to reduce emissions when compressors along the pipeline are taken off-line, as well as installing compressor rod packing systems and replacing older equipment (flanges, valves and fittings) along the pipelines."[8]

California's oil and gas sector includes onshore and offshore operations. The Oil and Gas Extraction GHG Emission Reduction measure targets fugitive emissions (which are mostly methane) from extraction sources; these emissions are estimated to be 0.3 million metric tons CO_2 equivalent ($MMTCO_2e$) in 2020 and currently account for approximately 5% of the GHG emissions from this sector. With these estimates, CARB acknowledges that while historical trends are used for calculations, this sector could see even more growth in the future with increased oil extraction as a result of increased crude oil prices. The oil and gas extraction emission reduction measures are projected to result in a 0.2 $MMTCO_2e$ emissions decrease per year beginning in 2015, a 67% reduction in emissions.[9] The 2020 inventory projections for the oil and gas transmission category are 1.7 $MMTCO_2e$ and the implementation of the scoping plan will reduce emissions by 0.9 $MMTCO_2e$, a greater than 50% reduction in emissions.[10] These planned GHG emission reduction measures will result in significant economic benefits. The cost savings for the oil and gas GHG reduction extraction measures are expected to be $3.7 million annually, while the reduction measures for oil and gas transmission are projected to save $17 million annually.[11]

California's efforts to reduce GHG emissions from all sources across the state is evidence that technology standards and practices are available to support mandatory reductions.

[7] California Air Resources Board, Scoping Plan Measures Implementation Timeline, July 1, 2010, http://www.arb.ca.gov/cc/scopingplan/sp_measures_implementation_timeline.pdf.

[8] "Climate Change Scoping Plan Appendices, Volume 1: Supporting Documents and Measure Detail, a framework for change," California Air Resources Board, December 2008, pp. C-153 and C-154, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf#page=184.

[9] *Id.* p. C-153.

[10] *Id*. pp. C-153 and C-154.

[11] *Id.*

II. REVIEW OF METHANE EMISSIONS CONTROLS BY MAJOR OIL AND GAS SOURCE TYPE

This section provides a review of currently available technologies and practices, as well as existing regulatory initiatives, to reduce methane emissions for each of the following major oil and gas source types: pneumatics, compressors, dehydrators, tanks, wells, pipelines and flares. The section ends with a more general section on the value of directed inspection and maintenance practices.

In general, methane emissions occur across all sectors of the natural gas industry (*i.e.*, production, processing, transmission and distribution) in both onshore and offshore applications. Emissions occur during normal operations and routine maintenance events and also as a result of leaks and system upsets. Fugitive emissions occur as a result of both intentional venting and unintentional leakage. In addition to natural gas operations, methane emissions also occur in the oil industry, primarily from field production operations (*e.g.*, the venting of associated gas from oil wells), oil storage tanks, and production-related equipment (*e.g.*, gas dehydrators and pneumatic devices). The following subsections discuss the multiple control technologies available to significantly reduce the methane emissions of a particular source (*e.g.*, venting from the device, leaks, offshore applications, etc.).

A. Pneumatic Devices

Pneumatic devices are used in all sectors of the oil and natural gas industry for liquid level controllers, pressure regulators and valve controllers. Such devices are typically powered by natural gas, although some are powered by electricity or compressed air. The natural gas powered devices vent large amounts of methane to the atmosphere as part of their normal operations. There are 3 main types of pneumatic devices in use in the natural gas industry, which include: (1) continuous bleed devices that generally bleed natural gas continuously and act to modulate flow, liquid level or pressure; (2) actuating or intermittent bleed devices that open and close, releasing gas to the atmosphere periodically; and (3) self-contained controllers that do not release any gas to the atmosphere, sending the gas downstream instead. The Natural Gas STAR Program defines any pneumatic device that bleeds over 6 standard cubic feet per hour (scfh) of natural gas as a high-bleed device. The Natural Gas STAR Program states:

> In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.[12]

The production sector includes by far the largest number of gas powered pneumatic devices, estimated at around 400,000.[13] Pneumatic devices are the largest source of methane emissions

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[12] Lessons Learned, Natural Gas STAR Partners, "Options for Reducing Emissions from Pneumatic Devices in the Natural Gas Industry," October 2006, p. 4, http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.
[13] *Id.,* p. 2.

from the oil and natural gas production sector, totaling an estimated 43 Bcf—or 35 percent— of all production-based emissions (based on 2009 data).[14] In this sector, controllers are used to regulate temperature in dehydrator regenerators, regulate pressure in flash tanks and control and monitor gas and liquid flows and levels in dehydrators and separators. The transmission sector is the second largest sector for methane emissions from pneumatic devices, with an estimated 85,000 devices used to "actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities."[15] Pneumatic devices in the transmission sector account for an estimated 11 Bcf of methane annually (based on 2009 data).[16] Around 13,000 of the pneumatic devices are used in the processing sector at gas gathering and booster stations for compressor and glycol dehydration control and at processing plants for isolation valves.[17]

Emissions from natural gas driven pneumatic valve and pump devices are known to be major contributors to fugitive emissions from the oil and gas production sector. Yet, the emission factors used to estimate overall emissions from pneumatic devices may underestimate emissions from this source category. Reported uncertainties can range from ±33% to ±407%.[18] In addition to the uncertainty in inventory estimates, the sheer number of pneumatic devices makes this a particularly important source category to focus on. Emissions reductions from the hundreds of thousands of pneumatic devices used throughout the oil and gas sector have the potential to greatly influence overall emissions and associated impacts. The magnitude and importance of this emissions source should also drive a greater emphasis on compliance via direct measurement (*e.g.*, metering), rather than compliance based on engineering estimates (*e.g.*, Original Equipment Manufacturer (OEM) emission factors). EPA should require installation of gas meters at new installations in order to monitor instrument gas consumption and provide an accurate determination of methane emissions.

1. Existing State Programs to Reduce Methane Emissions from Pneumatic Devices

The following state programs demonstrate that mandatory controls for reducing methane emissions are possible. EPA should consider these standards as minimum requirements for regulating sources under the NSPS. Regulations aimed at reducing VOCs and HAPs are relevant to consider because of the corresponding reductions in methane emissions that are achievable through implementation of these control technologies and practices.

[14] EPA Natural Gas STAR, http://www.epa.gov/gasstar/basic-information/index.html#sources.
[15] Lessons Learned, Natural Gas STAR Partners, "Options for Reducing Emissions from Pneumatic Devices in the Natural Gas Industry," October 2006, p. 2.
[16] EPA Natural Gas STAR, http://www.epa.gov/gasstar/basic-information/index.html#sources.
[17] Lessons Learned, Natural Gas STAR Partners, "Options for Reducing Emissions from Pneumatic Devices in the Natural Gas Industry," October 2006, p. 2.
[18] See, e.g., API Compendium of Greenhouse Gas Emissions Methodologies For the Oil and Natural Gas Industry, August 2009, Table 5-15, pages 5-68 and 5-69, http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf.

Colorado

The Colorado Department of Public Health and Environment's Air Pollution Control Division addresses oil and gas related ozone issues in Regulation Number 7, which controls VOCs and nitrogen oxides (NO_X) for the 1-hour and 8-hour ozone nonattainment or attainment/maintenance areas, as well as statewide. Under these regulations, all new pneumatic devices are required to be low-bleed and existing high-bleed (any device that emits more than 6 standard cubic feet per hour (scfh)) pneumatic devices must be replaced or retrofitted to meet the state's low-bleed specifications of 6 or fewer scfh of natural gas.[19] This regulation is aimed at reducing VOC emissions, but methane emissions are reduced as a co-benefit of the requirements.[20] For the rest of the state, new, replaced or repaired pneumatic devices are required to install low-bleed valves, where technically feasible.[21]

Wyoming

The Wyoming Department of Environmental Quality's permitting requirements cover pneumatic pumps and controllers. While the main goal of the state's rules is to reduce VOC and HAP emissions, methane reductions are a co-benefit of the controls. Wyoming's most restrictive requirements for pneumatic pumps apply to the Jonah and Pinedale Anticline Development Area, where pneumatic heat trace pumps and other pneumatic pumps at all new and modified facilities must meet a 98% control requirement for VOC and HAP emissions.[22]

In addition, Wyoming's requirements for new facilities with natural gas operated pneumatic controllers, or new natural gas operated pneumatic controllers at modified facilities, dictate that such controllers must be low or no-bleed (where low bleed is 6 scfh or less) or the controller discharge stream must be routed to a closed loop system. For modifications at facilities with existing pneumatic controllers, the devices must be replaced or converted in order to meet the same requirements for new facilities within 60 days of modification.[23]

California

CARB's proposed GHG rules (described above) include control measures for pneumatics to replace high-bleed devices with low-bleed bleed devices.[24]

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[19] There are certain exceptions to these requirements for high-bleed pneumatic controllers that need to remain in place due to safety issues.
[20] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, "Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides)," 5 CCR 1001-9.
[21] Colorado Code of Regulations, 2 CCR 404-1 "Practice and Procedure," §805 b(2)E, http://www.sos.state.co.us/CCR.
[22] Wyoming DEQ, C6 S2 O&G Production Facilities Permitting Guidance, March 2010, p. 19.
[23] *Id,* 10, 19.
[24] "Climate Change Scoping Plan Appendices, Volume 1: Supporting Documents and Measure Detail, a framework for change," California Air Resources Board, December 2008, C-153, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf#page=184.

2. Available Proven Technologies for Pneumatic Devices

EPA's own Natural Gas STAR program demonstrates that there are many currently available, technically feasible, and cost-effective technologies that can greatly reduce methane emissions from pneumatic devices. EPA should, at a minimum, require the following technologies and operating practices as part of its revised NSPS for oil and natural gas systems.

Require Pneumatic Devices That Use Instrument Air or Mechanical Controls, Nitrogen Gas, or Electric Valve Controllers in Place of Gas Powered Pneumatic Devices

The installation of pneumatic controls that use instrument air rather than gas powered low-bleed or no-bleed devices can achieve 100% methane emission reductions. Many Natural Gas STAR partners have realized economic benefits from switching to instrument air. This technology can be used where electrical power is available, or to further reduce energy demands and to expand possible usage, instrument air devices can be converted to solar-powered, battery-operated devices. Several Natural Gas STAR partners have had success with this option.[25]

In addition to economic benefits from using instrument air, natural gas companies can achieve an extended life for control devices and improve operational efficiencies beyond that of gas powered devices. Significant safety improvements are also realized since flammable natural gas is no longer used for this process, which is of particular importance at offshore operations where there are greater risks from flammable and hazardous materials.[26]

Pneumatic controllers can also employ mechanical control, nitrogen gas, or electric valve controllers. Some Natural Gas STAR partners have reported success with the use of mechanical controls in remote, non-electrified production, processes, transmission and distribution sites. "The most common mechanical control device is a level controller, which translates the position of a liquid-level float to the drain valve position with mechanical linkages. There is no gas usage in either the process measurement or valve actuation, and reliability is very high."[27] Use of nitrogen gas or electric valve controllers are additional alternatives to gas pneumatics, although they each present significant limitations.[28]

CARB lists replacing gas powered pneumatic devices with compressed air systems or nitrogen gas as a Best Management Practice (BMP) for oil and gas sources.[29] EPA should require that all new pneumatic device installations use instrument air, powered either by electricity of solar energy or use mechanical controls, nitrogen gas or electric valves if instrument air is not feasible. All modified sources should be required to convert gas powered pneumatic control devices to

[25] EPA, "Solar Power Applications for Methane Emissions Mitigation: Lessons Learned from the Natural Gas STAR Program," 8/31/2009, 15-23.
[26] *Id.* 5,6.
[27] Lessons Learned, Natural Gas STAR Partners, "Convert Pneumatics to Mechanical Controls," September 2004, p. 1 & 2.
[28] Lessons Learned, Natural Gas STAR Partners, "Convert Gas Pneumatic Controls to Instrument Air," October 2006, p. 15.
[29] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

meet the standards for new sources. Reductions in methane emissions of 100% would be expected from this technology.

Require Low-Bleed Pneumatic Devices for New Installations and Require Modified Sources to Retrofit High-Bleed Devices with Low-Bleed Devices

Methane emission reductions can be achieved by requiring low-bleed devices in place of high-bleed natural gas powered pneumatic devices, and by improving maintenance in order to reduce methane emissions. Installing low-bleed pneumatic devices instead of high-bleed devices is a cost-effective methane reduction strategy. Depending on the device installed, annual savings from emission reductions can vary from $315 to $1820 and the cost of installation is often recovered in one year.[30] For example, the installation of a low-bleed liquid level controller, at an initial $513 for the unit, would save $1165 annually.[31] For any new and modified installations where non-gas powered pneumatic devices are not feasible, EPA should require the use of low-bleed devices.

For modified sources, switching high-bleed pneumatic devices to low-bleed involves replacing, retrofitting and maintaining the devices and using all or one of these strategies in order to achieve the low-bleed rate of less than 6 scfh natural gas (over 50 Mcf/year). Significant savings and methane emission reductions have been achieved by Natural Gas STAR partners who have implemented these strategies.[32] Replacing, retrofitting and maintaining pneumatic devices also has the added benefit of increasing operational efficiencies for the devices by improving both system-wide performance and reliability, and monitoring of parameters such as gas flow, pressure, or liquid level.[33]

EPA should require that any new pneumatic devices that must be gas-powered be low-bleed or that modified devices be replaced or retrofitted to meet low-bleed criteria. As discussed above, the states of Colorado and Wyoming already have programs in place for requiring low-bleed pneumatic devices and California is currently considering this strategy as part of its greenhouse gas reduction plan. In addition, both the Bureau of Land Management (BLM) and CARB list the use of low-bleed pneumatics as a BMP for oil and gas sources.[34] This proven best management practice should be required for all new pneumatic devices in order to achieve emission reductions of 98% for these units.

3. Summary Recommendations for Pneumatic Devices

EPA should implement the following technology standards and operating practices for all new pneumatic devices:

[30] Lessons Learned, Natural Gas STAR Partners, "Options for Reducing Emissions from Pneumatic Devices in the Natural Gas Industry," October 2006, p. 4.
[31] *Id.*, p. 7.
[32] *Id.*, p. 1.
[33] *Id.,* p. 4.
[34] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

- *Require Pneumatic Devices That Use Instrument Air or Mechanical Controls, Nitrogen Gas, or Electric Valve Controllers in Place of Gas Powered Pneumatic Devices*
  EPA should require that all new pneumatic device installations use instrument air, powered either by electricity of solar energy or use mechanical controls, nitrogen gas or electric valves if instrument air is not feasible. All modified sources should be required to convert gas powered pneumatic control devices to meet the standards for new sources. Reductions in methane emissions of 100% would be expected from this technology.

- *Require Low-Bleed Pneumatic Devices for New Installations and Require Modified Sources to Retrofit High-Bleed Devices with Low-Bleed Devices*
  EPA should require that any new pneumatic devices that must be gas-powered be low-bleed or that modified devices be replaced or retrofitted to meet low-bleed criteria.

B. Compressors

Fugitive methane emissions from compressors (*e.g.*, from compressor seals) are a significant source of methane emissions from the natural gas processing sector. Compressors are also integral in the transmission of natural gas from field production and processing to the distribution sector. Compressor station facilities are used to transport gas through the network of transmission lines throughout the United States. Fugitive methane emissions from these compressor stations account for a significant portion of all emissions from the transmission sector. Compressors housed at storage facilities are also a large source of fugitive methane emissions. At these facilities, natural gas is stored during periods of low demand (*e.g.*, in summer), and subsequently processed and distributed during periods of high demand (*e.g.*, in winter).

According to U.S. Greenhouse Gas Inventory data, compressor fugitive emissions, venting and engine exhaust account for about 12 Bcf—or about 10 percent—of methane emissions from the production sector. Reciprocating compressors account for another 16 Bcf and 41 Bcf—or about 50 percent and 40 percent—of methane emissions from the processing and transmission sectors, respectively. All told, methane emissions from compressors reportedly account for at least one fifth of all methane emissions from oil and gas systems.

These estimates, however, may underestimate actual emissions. According to EPA's recent rulemakings for the Mandatory Reporting of Greenhouse Gases program, several emissions sources are believed to be "significantly underestimated" in the U.S. GHG Inventory (EPA/GRI/Radian, 1996).[35,36] Specifically, EPA identifies the following sources of under-reported emissions: (1) well venting for liquids unloading; (2) gas well venting during well completions; (3) gas well venting during well workovers; (4) crude oil and condensate storage tanks; (5) *centrifugal compressor wet seal degassing venting*; and (6) flaring. According to EPA, the emissions estimates for these sources "do not correctly reflect the operational practices of

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[35] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.
[36] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 7.

today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[37] EPA includes revised emission factors for four of these underestimated sources, including the addition of a factor for centrifugal compressor wet seal degassing venting of 233 metric tons per year, or 12 million cubic feet per year (MMcf/yr).[38] Overall, the revisions to just these four sources results in a more than 100% increase in estimated emissions from the oil and gas production sector and a 67% increase in estimated emissions from the transmission and storage sector.[39] These enormous underestimates alone are enough of a reason to insist on rigorous performance standards and work practices for these particular categories. However, there is even more evidence that the emissions estimates for these and other sources remain uncertain and continue to be greatly underestimated.

Preliminary findings from an EPA-funded project at the University of Texas indicate that fugitive methane emissions from compressor engines can be substantially higher than expected from the currently accepted emission factors.[40] Specifically, current emission factor estimates do not distinguish compressor seal emissions by compressor type (reciprocating or centrifugal) and do not distinguish between emissions from the seal face and emissions from seal oil degassing.[41]

It is worth noting that direct measurement of emissions from both reciprocating and centrifugal compressors is possible as a means to accurately demonstrate compliance with performance standards established by EPA. EPA proposed direct measurement methods for determining reported emissions under the Mandatory Reporting Rule (MRR).[42]

1. <u>Existing State and International Programs to Reduce Methane Emissions from Compressors</u>

The following state and international programs demonstrate that mandatory controls for reducing methane emissions are possible. EPA should consider these standards as minimum requirements for regulating sources under the NSPS. Regulations aimed at reducing VOCs and HAPs are relevant to consider because of the corresponding reductions in methane emissions that are achievable through implementation of these control technologies and practices.

California

The state of California proposed greenhouse gas rules (described in the Introduction and Summary Recommendations section above) that include control measures for compressors to improve operating practices and therefore reduce emissions when compressors are taken off-line

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[37] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 23.
[38] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 8, Table 1.
[39] *Id.* at 9.
[40] University of Texas (Cooperative Agreement number XA-83376101-0).
[41] Quality Assurance Project Plan, Greenhouse Gas (GHG) Emission Factor Development Project Cooperative Agreement number XA-83376101-0, January 30, 2008, Dr. David T. Allen (Principal Investigator) and Cyril Durrenberger (Project Quality Assurance Officer) Center for Energy and Environmental Resources University of Texas J.J. Pickle Research Campus 10100 Burnet Road, Mail Code R7100 Austin, Texas 78758, p.8.
[42] 75 FR 18608, April 12, 2010.

and install compressor rod packing systems. This would apply to compressors in both the oil and natural gas extraction and transmission sectors.[43]

Cherkasytransgas

Cherkasytransgas, a Ukrainian natural gas transmission company with a capacity to transmit 120 billion cubic meters of natural gas annually, implemented a directed inspection and maintenance program at its compressor stations in 2002. Since then the company has achieved huge reductions in methane emissions from these sources through monitoring, leak repair, and equipment and valve sealant upgrades. In 2002, the company identified and repaired leaks, reducing methane emissions by 1.9 million cubic meters per year. In 2006, the company again conducted repairs and installed high efficiency equipment, reducing emissions by 5.9 million cubic meters annually. During the last round of repairs in 2008-2009, the company upgraded the sealant on 174 valves at transmission stations, distribution stations and linear pipes. These improvements reduced annual methane emissions by 3.5 million cubic meters.[44]

2. Available Proven Technologies for Compressors

EPA's own Natural Gas STAR program provides evidence that there are many available, technically feasible, and cost-effective technologies that can greatly reduce methane emissions from gas compression activities. These options include both: (1) technology standards for compressor equipment; and (2) improving operating practices to reduce emissions (*e.g.*, when compressors are taken off-line). EPA should, at a minimum, require the following technologies and operating practices as part of its revised NSPS for oil and natural gas systems.

Require the Use of State-of-the-Art Compressor Rod-Packing Technology

EPA should require the use of state-of-the-art rod-packing technology and identify a replacement threshold for replacing packing rings and piston rods as a practical method to reduce methane emissions from reciprocating compressors. Both the BLM and CARB already list compressor rod-packing technology as a BMP for oil and gas sources.[45]

Leakage can be reduced through a requirement to develop a proper monitoring plan and a cost-effective schedule for replacing packing rings and piston rods. Monitoring and replacing compressor rod packing systems on a regular basis can greatly reduce methane emissions from compressors. According to EPA Natural Gas STAR partner reports, as packing deteriorates, leak rates can increase to the level at which replacing packing rings more frequently can be

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[43] "Climate Change Scoping Plan Appendices, Volume 1: Supporting Documents and Measure Detail, a framework for change," California Air Resources Board, December 2008, C-153 and C-154, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf#page=184.

[44] Methane to Markets, Oil & Gas Methane Reduction Project Opportunity, "Directed Inspection and Maintenance and Valve Sealant Updgrades," Cherkasytransgas, Cherkassy, Ukraine, http://www.methanetomarkets.org/projects/projectDetail.aspx?ID=1152.

[45] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

economically justified.[46] In addition, more frequent ring replacement might actually extend the life of the compressor rod. EPA should require operators to establish baseline leakage rates and monitor changes in leakage rates to establish an emission threshold and corresponding replacement frequency similar to EPA's "economic replacement threshold" analysis promoted through its Natural Gas STAR program.[47]

For example, conventional bronze-metallic packing rings require replacement about every "three to five years,"[48] but a more precise monitoring program will allow individual applications to optimize replacement so as to extend the life of the equipment and reduce increasing emissions. Requiring an aggressive monitoring and replacement schedule is an essential component of a comprehensive performance standard for this source. In addition to monitoring leakage rates, operators should be required to regularly monitor appropriate lubrication and cooling parameters to help minimize wear on packing rings.

The most advanced ring materials and designs for packing cases should guide EPA's performance standard for this source. New packing ring materials (*e.g.*, high-performance non-metallics and polymers), types, and entirely new packing systems are available and becoming more common. There are many examples of companies that provide new low emission packing rings and packing case assemblies.[49] EPA should consider all available emission-lowering rod packing technologies when setting the performance standard for this source.

EPA reports there are 51,000 reciprocating compressors operating in the U.S. natural gas industry (2006), accounting for about 72.4 Bcf/yr of methane gas emissions.[50] EPA further reports that new rod packing systems, properly installed and operated, lose approximately 12 scfh compared with emissions that range from tens of scfh to hundreds of scfh for aged systems (EPA uses an example of 900 scfh).[51] If, as reported by EPA, economic replacement of rods and rings for applications demanding a payback of less than one year would mean replacing equipment when leak rates reach a level of 376 scfh, then these systems would see a 97% reduction in emissions.[52] New state-of-the-art rod packing technology required to emit no more than 12 scfh at installation would still represent a 90% reduction in methane emissions compared

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[46] Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", October 2006, http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.
[47] *Id.*
[48] *Id* at 3.
[49] Specific examples include: (1) Compressor Engineering Corp (CECO) Low Emission Packing (LEP™), *see* http://www.tryceco.com/ceco-parts-and-repair/rings-rider-band-rod-packing/lep-low-emission-packing.htm; (2) Cook Compression's "COOK CLEAN emission-control solutions," "Seal Assist System™, the ultimate in emissions control," and "[v]ented and buffered cases specially designed for your application to reduce fugitive emissions," see http://www.cookcompression.com/index.cfm/lev2/813/Packing.Cases ; (3) Hoerbiger's "BCD balanced cap design" which the company promotes as a "new low emission packing ring that operates at low temperatures and maintains the seal even during compressor shutdown," see company materials at http://www.hoerbiger.com/Packing-rings.14186.0.html?&L=33; (4) Aavolyn Corporation's ring and packing assemblies made of various materials (bronze, cast iron and Teflon blends) that "keep gas from leaking from the cylinder to the atmosphere" and "prevent leakage of gas along the rod when the compressor is shut down under the load" and include "Green Compressor Packing" technology, see http://www.aavolyn.com/cg020001.htm.
[50] Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Compressor Rod Packing Systems", October 2006, http://www.epa.gov/gasstar/documents/ll_rodpack.pdf.
[51] *Id.*
[52] *Id* at 8.

to systems operating with leak rates of only 120 scfh.

To achieve a 90% reduction in emissions from this source, EPA should require new technology standards and operating practices that prescribe initial leakage rates no greater than 12 scfh and replacement of compressor rod packing when leakage rates exceed 120 scfh,[53] or when indicated by an established source-specific replacement threshold that maximizes methane reductions while also considering cost-effectiveness.

Require the Use of Dry Seals in Centrifugal Compressors

Centrifugal compressors are common in the production and transmission sectors of natural gas systems. Replacing wet seals (oil seals) used on the rotating shafts of the compressors with dry seals can significantly reduce methane emissions from this source. In fact, installing two or more dry seals together, in series, is even more effective in reducing emissions. According to EPA, these types of "tandem dry seals" result in less than 1% of the leakage of a wet seal system that is vented to the atmosphere and "cost considerably less to operate."[54]

The use of dry seals is proven and has been recently documented by the Global Methane Initiative.[55] Specifically, methane emissions were shown to be 99.99% lower with the use of dry seals in an application in Mexico in 2010.[56] In 2006, EPA reported that 90% of all new compressors are already equipped with dry gas seal systems. In addition, both the BLM and CARB list the use of dry seals as a BMP for oil and gas sources.[57]

This technology is also an effective means of reducing methane emissions at offshore oil and gas operations. A recent paper on offshore platform methane reduction strategies analyzed offshore oil and gas methane emissions and control strategies, and devised an emission reduction strategy for the most significant sources at the lowest cost. The replacement of centrifugal compressor wet seals with dry seals is one of the recommended strategies for reducing methane emissions in offshore applications.[58]

The world's largest natural gas company, Gazprom (with operations in Russia), has committed to replacing wet seals and dry seals at centrifugal compressors (which total more than 4,000). Between 2006 and 2008, the company converted seals at 59 compressor stations and 250 gas

[53] 120 scfm leak reduction rate would require roughly 2 years payback assuming a gas cost of $7/Mcf, a 10% interest rate and 8,000 hours of operation.
[54] Lessons Learned, Natural Gas STAR Partners, "Replacing Wet Seals With Dry Seals in Centrifugal Compressors", October 2006, http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.
[55] *See*, e.g., April 2010 (http://www.epa.gov/gasstar/documents/workshops/ashgabat-2010/0427_1135_compressors.pdf), March 2010 (http://www.methanetomarkets.org/expo/docs/postexpo/oil_betancourt_2.pdf) and September 2009 (http://www.methanetomarkets.org/documents/events_oilgas_20090914_robinson3.pdf) Methane to Markets presentations.
[56] Petróleos Mexicanos (Pemex) demonstrated a reduction in emission rate from 43.11 scfm to 0.02 scfm with seal replacement, *see* http://www.methanetomarkets.org/expo/docs/postexpo/oil_betancourt_2.pdf.
[57] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[58] Bylin, Carey et al. for Society of Petroleum Engineers, "Designing the Ideal Offshore Platform Methane Mitigation Strategy," 2010, p. 1.

pumping aggregate superchargers located at extraction facilities, gas transport facilities and underground storage facilities.[59]

Since dry seal conversions may not be technically feasible for all compressors due to housing design and/or operational requirements, EPA should also investigate seal oil degassing vent recovery technology as an alternative performance technology requirement, where dry seal installations are not possible.[60]

EPA should require the installation of tandem dry seals on all new compressors, or seal oil degassing vent recovery devices in cases where dry seals are not technically feasible. If, according to EPA, methane emissions typically range from 40 to 200 scfm for wet seals and from 0.5 to 3 scfm for dry seals, then EPA should require methane emissions from new units to emit no more than 3 scfm from the dry seals (representing at least a 92.5% reduction in emissions from this source). With demonstrated installations reporting emission reductions over 99% and rates as low as 0.02 scfm (approximately 10 Mcf/yr at 8,000 hours of operation), this should be an achievable standard. Based on EPA's recent estimate of 12 MMcf/yr from centrifugal compressor wet seal degassing venting, reductions of over 90% from this source would drop this emission factor estimate for new units to just over 1 MMcf/yr (or just under 3 scfm for a unit that operates 8,000 hours).[61]

In addition to reducing methane emissions, replacing wet seals with dry seals significantly reduces operating costs and increases compressor efficiency. Specifically, EPA reports that dry seals: (1) are safer to operate because there is no need to operate a high-pressure oil system; (2) are mechanically simpler; (3) consume less energy (90–95% less); (4) result in less compressor downtime; (5) have lower maintenance costs and last twice as long as wet seals; and (6) their use does not result in contamination of the gas stream and degradation of the pipeline from oil usage.[62]

Require the Use of Air or Electric Starters Instead of Gas Starters

Gas starters use natural gas to power the starter motor and then vent the discharge gas to the atmosphere. Compressor starters that use compressed air or electricity instead of natural gas to power the starter motor are not sources of methane emissions. Requiring the use of air or electric starters instead of gas starters for all natural gas pneumatic starter motors will ensure reduced methane emissions, as well as reduced VOC and HAP emissions, from this source. A standard air starter would require a stationary or mobile air compressor (with an electrical power source). Operation costs would include the cost of the electrical power needed to compress the air. Replacing starter expansion turbines with an electric motor starter, similar to an automobile

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[59] Oil & Gas Methane Reduction Project Opportunity, Compressor Seal Conversions, OAO Gazprom, (http://www.methanetomarkets.org/projects/projectDetail.aspx?ID=1151) and Gazprom Activities on Methane Emissions Reduction, G.S. Akopova, Laboratory of Environmental Protection and Resource Saving, Moscow 2010, at 13, (http://www.methanetomarkets.org/expo/docs/postexpo/oil_apokova.pdf).
[60] *See* slides 11-12 from Methane to Markets April 2010 presentation (http://www.epa.gov/gasstar/documents/workshops/ashgabat-2010/0427_1135_compressors.pdf).
[61] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 8, Table 1.
[62] Lessons Learned, Natural Gas STAR Partners, "Replacing Wet Seals With Dry Seals in Centrifugal Compressors", October 2006, http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.

engine starter, may include a connection to utility electrical power, site generated power, or solar recharged batteries. Use of air and electric starters completely eliminates the venting of methane to the atmosphere and the leakage of methane through the gas shutoff valve. EPA has reported this technology as a cost-effective control technique in its Natural Gas STAR program.[63]

EPA has reported a 1,524 thousand cubic feet (Mcf) per year average leakage rate from compressor starter lines.[64] An average methane emission factor for compressor engines used in gas processing is about 4 million cubic feet (MMcf) per year for reciprocating engines and about 8 MMcf per year for centrifugal engines.[65] Requiring air or electric starters on all applicable engines would reduce methane emissions by roughly 40% in new reciprocating engine applications and 20% in new centrifugal engine applications. CARB already lists the use of air or electric starters as a BMP for oil and gas sources.[66]

Require the Use of State-of-the-Art Compressor Cylinder Unloader Technology and Require Regular Replacement

Compressor cylinder unloaders employed in the transmission sector are used to control gas volumes (*e.g.*, for capacity control, to prevent an overload when there is an upset in the system, or to reduce the load during engine start-up, etc.). Unloaders can be a significant source of fugitive methane emissions (*e.g.*, from leaking o-rings, covers and pressure packing) and have been identified as one of the top causes of unscheduled shutdowns for reciprocating compressor engines.[67]

EPA should thoroughly investigate the state-of-the-art technology for unloaders and require the use of the best available technologies to reduce vented emissions from this source. Examples of such technologies are the use of multiple innovative sealing elements (including elastomeric sealing elements) to reduce emissions and the use of port/plug-type designs to avoid operational problems inherent in finger-type unloader designs.[68]

In order to reduce the amount of unscheduled shutdowns and frequent maintenance required for aging unloader systems (and the associated fugitive emissions that result from these episodes), EPA should specify a conservative replacement period that will ensure optimal equipment performance over the life of the unloader system and parts. One possible method would be to establish an acceptable emission threshold and specify a corresponding replacement frequency based on that threshold.

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[63] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet Nos. 103 and 108, http://www.epa.gov/gasstar/documents/replacegas.pdf and http://www.epa.gov/gasstar/documents/installelectricstarters.pdf.
[64] EPA ORD, "Methane Emissions from The Natural Gas Industry", Volume 8, GRI-94 /0257.23, EPA 600/R-96-080h, June 1996, p. 58.
[65] *Id.* at 48.
[66] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[67] "Compressor Valves and Unloaders for Reciprocating Compressors - An OEM's Perspective", S. Foreman Dresser-Rand, Painted Post, NY, USA, available at http://www.dresser-rand.com/techpapers/tp015.pdf.
[68] *See* EPA Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 110, http://www.epa.gov/gasstar/documents/replacecylinder.pdf.

Potential methane emission reductions from using the best available compressor cylinder unloader technology are not easily quantified and depend, among other things, on compressor maintenance activities. However, it is important to include technology requirements and replacement schedules for this source since the potential for fugitive methane emissions is significant. Fugitive methane emissions from faulty unloaders have been reported to be as high as 3.5 MMcf per compressor engine,[69] which represents a huge fraction of average annual emission rates for compressors at transmission sites (roughly 5.5 MMcf/yr and 11 MMcf/yr for an average reciprocating and centrifugal compressor, respectively).[70]

CARB already lists the use of cylinder unloaders and their regular replacement as a BMP for oil and gas sources.[71]

Require Operating Practices That Eliminate or Reroute Gas Leakage When Taking Compressors Off-line

When taking compressors offline for operational reasons, EPA should require operators to keep compressors pressurized and to connect the blowdown vent lines to the fuel gas system in order to allow the gas that is normally vented to be used as fuel while the compressor is off-line. In situations where routing gas to the fuel gas system is not possible EPA should require the installation of a static seal on the compressor rods to eliminate rod-packing leaks that occur during the shutdown process. Keeping compressors fully pressurized avoids significant fugitive emissions from leaks across the unit valves.

For situations where compressors cannot remain pressurized when they are taken offline for maintenance and for system shutdowns, EPA should require collection and re-routing of any vented gas. Not allowing venting to the atmosphere of the high-pressure gas that is left in the compressor when it is taken offline (*i.e.*, blowdowns) will require capturing the gas and re-routing it for other use (*e.g.*, to the sales line). The design of blowdown systems and emergency shutdown system practices to capture gas should be required in accordance with acceptable industry safety standards (*e.g.*, OSHA, API, ANSI, ASME, etc.). Rerouting highly-combustible gases has the added benefit of reducing safety risks in the work area.

EPA has reported huge savings by Natural Gas STAR partners when maintaining pressurized systems during shutdowns. Keeping the system pressurized can reportedly, alone, avoid over 4 MMcf/yr of methane emissions per compressor.[72] When also requiring the rerouting of gas to the fuel system, methane emissions savings can be as high as 5.3 MMcf/yr per unit.[73] EPA-reported average emission rates for compressor blowdown valves are an order of magnitude higher in depressurized systems than in pressurized systems (1.4 MMcf/yr for pressurized systems

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[69] *Id.*
[70] EPA ORD, "Methane Emissions from The Natural Gas Industry", Volume 8, GRI-94 /0257.23, EPA 600/R-96-080h, June 1996, p. 52.
[71] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[72] Lessons Learned, Natural Gas STAR Partners, "Reducing Emissions When Taking Compressors Off-Line", October 2006, p. 1, http://www.epa.gov/gasstar/documents/ll_compressorsoffline.pdf.
[73] *Id.*

compared with over 14 MMcf/yr for depressurized systems).[74] Again, these emission rate estimates represent a substantial portion of the overall methane emission rates from compressors (roughly 5.5 MMcf/yr and 11 MMcf/yr for an average reciprocating and centrifugal compressor, respectively).[75]

Significant emissions reductions and cost saving will result from avoiding routine compressor blowdown and eliminating or rerouting leakage. EPA must require operating practices to ensure the best system of emissions reductions is established.

Require Direct Inspection and Maintenance at Compressor Stations

Direct Inspection and Maintenance (DI&M) is "a proven management practice for cost-effective reduction of methane emissions" that can significantly reduce fugitive methane emissions from the gas processing sector.[76] A DI&M is not the same thing as EPA's regulatory leak detection and repair (LDAR) program for reducing VOC emissions.[77] A successful DI&M program includes a baseline survey, cost-effective repairs and subsequent targeted surveys based on findings from the initial baseline survey. In general, the cost of the baseline survey is reportedly recovered in gas savings during the first year.[78] The costs of subsequent surveys are minimized by focusing the components that were identified through the initial baseline study as having a high potential for leakage. A variety of screening and measurement devices (*e.g.*, infrared gas imaging, optical remote leak detection, etc.) can be used to obtain accurate leak data and high volume gas samplers can be used to identify and quantify leaks.[79] According to EPA Natural Gas STAR partners, a DI&M program should "target the five categories of equipment components that contribute to the majority of methane losses: block valves, control valves, connectors, compressor seals, and open-ended lines."[80] Additionally, a DI&M program should include regular inspection of blowdown valves at compressor stations, which can be significant methane emissions sources due to substantial pressure, thermal and mechanical stresses.[81]

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[74] EPA ORD, "Methane Emissions from The Natural Gas Industry", Volume 8, GRI-94 /0257.23, EPA 600/R-96-080h, June 1996, p. 56. *NOTE*: the depressurized emission rates do *not* include the vented emissions from depressuring the compressor.

[75] *Id.* at 52.

[76] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf

[77] *See*, NSPS Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants.

[78] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf

[79] *See, e.g.*, Directed Inspection and Maintenance (DI&M) at Gas Processing Plants, Innovative Technologies for the Oil & Gas Industry: Product Capture, Process Optimization, and Pollution Prevention,
Targa Resources and the Gas Processors Association, July 27, 2006 Hobbs, NM,
http://www.epa.gov/gasstar/documents/dim.pdf.

[80] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations," October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf

[81] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 601, "Inspect and Repair Compressor Station Blowdown Valves,"
http://www.epa.gov/gasstar/documents/inspectandrepaircompressorstationblowdownvalves.pdf.

A pilot study conducted by EPA and the Gas Technology Institute demonstrated a DI&M program at gas processing facilities that reduced methane emissions by up to 96%.[82] EPA should require all gas processing facilities to establish and implement a DI&M program to reduce fugitive methane emissions. Potential methane reductions from implementing a DI&M program will vary depending upon the operating characteristics of the facility but EPA should prescribe a program that represents the best available practices for DI&M.

Require Isolation Valves To Be Installed in Close Proximity to Compressors For All New Installations

When individual compressors are taken off-line, valves are used to isolate the unit and the natural gas between these valves is vented to the atmosphere. Similarly, when real or simulated emergencies occur at compressor stations, fire gate valves are activated to stop the flow of gas into the station. Through improved compressor facility design, the volume of methane gas that is vented when sections of isolated equipment are blown out or when fire gate valves are activated can be minimized.[83] EPA should require all new compressor stations to locate isolation valves and fire gate valves in close proximity to compressors in order to minimize the lengths of gas-filled piping to be vented to the atmosphere.

3. Summary Recommendations for Compressors

EPA should implement the following technology standards and operating practices for all new compressor engines:

- *Require the Use of State-of-the-Art Compressor Rod-Packing Technology*
  EPA should prescribe initial leakage rates no greater than 12 scfh and replacement of compressor rod packing when leakage rates exceed 120 scfh, or when indicated by an established source-specific replacement threshold that maximizes methane reductions while also considering cost-effectiveness.

- *Require the Use of Dry Seals in Centrifugal Compressors*
  EPA should require the installation of tandem dry seals on all new compressors, or seal oil degassing vent recovery devices in cases where dry seals are not technically feasible.

- *Require the Use of Air or Electric Starters Instead of Gas Starters*
  EPA should require the use of air or electric starters instead of gas starters for all natural gas pneumatic starter motors.

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[82] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf.
[83] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheets No. 606 and 608, "Design Isolation Valves to Minimize Gas Blowdown volumes" and "Move Fire Gates In to Reduce Venting at Compressor Stations,"
http://www.epa.gov/gasstar/documents/designisolationvalvestominimizegasblowdownvolumes.pdf and http://www.epa.gov/gasstar/documents/movefiregatesin.pdf.

- *Require the Use of State-of-the-Art Compressor Cylinder Unloader Technology and Require Regular Replacement*
  EPA should require the use of the best available unloader technologies to reduce vented emissions from this source. EPA should also specify a conservative replacement period that will ensure optimal equipment performance and minimize methane emissions over the life of the unloader system and parts.

- *Require Operating Practices That Eliminate or Reroute Gas Leakage When Taking Compressors Off-line*
  EPA should require operators to keep compressors pressurized and to connect the blowdown vent lines to the fuel gas system in order to allow the gas that is normally vented to be used as fuel while the compressor is off-line. In situations where routing gas to the fuel gas system is not possible, EPA should require the installation of a static seal on the compressor rods to eliminate rod-packing leaks that occur during the shutdown process. For situations where compressors cannot remain pressurized when they are taken offline for maintenance and for system shutdowns, EPA should require collection and re-routing of any vented gas.

- *Require Direct Inspection and Maintenance at Compressor Stations*
  EPA should require all gas processing facilities to establish and implement a DI&M program to reduce fugitive methane emissions. EPA's prescribed work practice should represent the best available practices for DI&M.

- *Require Isolation Valves To Be Installed in Close Proximity to Compressors For All New Installations*
  EPA should require all new compressor stations to locate isolation valves in close proximity to compressors in order to minimize the lengths of gas-filled piping to be vented to the atmosphere.

C. Dehydrators

Saturated water found in produced gas must be removed prior to gas transmission. Glycol dehydrators are the most common technology used to remove water from gas. Glycol dehydrators are sources of methane emissions from the reboiler vent and from pneumatic controllers. The glycol used to absorb water from the gas stream also absorbs a small amount of methane, which is then driven off to the atmosphere (along with water vapor) through the reboiler vent. The majority of glycol dehydrators are used in the production sector, although they are also used during processing, transmission and storage. Methane emissions from dehydrator vent stacks are highest in the production sector due both to the higher number of units and also to the fact that most production dehydrators do not operate with flash tank separators.

According to U.S. Greenhouse Gas Inventory data, dehydrators and pumps account for about 12 Bcf—or about 10 percent—of methane emissions from the production sector and an additional 1

Bcf—or about 3 percent—from the processing sector.[84] These estimates are based on dehydrator population estimates made up of 95% glycol dehydrators and 5% other types of dehydrators.[85]

Emission factors for glycol dehydrators are dependent on the existence of certain technologies, namely: (1) use of a flash tank; (2) use of stripping gas; (3) use of gas-driven pumps; and (4) use of vent controls routed to a burner. According to the EPA/GRI inventory, use of flash tanks can reduce methane emission rates by 98%.[86] The use of stripping gas increases methane emissions. Gas from the absorber outlet (or the flash tank) is sometimes used in the regenerator to help strip the water and other absorbed compounds out of the glycol; the methane that is in the stripping gas passes through the regenerator and to the atmospheric vent. These emissions can be significant.[87] According to EPA/GRI emission factors, the use of gas-driven pumps can also greatly increase methane emissions. Spent pumping gas is flashed off in the regenerator and can result in significant methane emissions (equivalent to over five times what is estimated for still vent emissions).[88] The use of combusted vent controls can reduce methane emissions and, in fact, the EPA/GRI inventory assumes no methane emissions from units that employ combustion vent controls.[89] Although primarily used to control HAP emissions (*e.g.*, benzene, toluene, ethylbenzene and xylenes (BTEX)) the methane in the vent can be used as fuel in the regenerator burner.

EPA proposed the use of engineering measurements as a means to report emissions from dehydrator vent stacks under EPA's Mandatory Reporting Rule for GHG emissions.[90] EPA's proposed use of estimates based on the GLYCalc™ simulation software was also supported by the Western Climate Initiative in its recommendations to EPA on measuring GHG emissions from the oil and gas industry. These same methods can be employed for compliance demonstration purposes, as appropriate.

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[84] Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2007, USEPA, April, 2009, *see* http://www.epa.gov/gasstar/basic-information/index.html#sources.

[85] EPA ORD, "Methane Emissions from The Natural Gas Industry", Volume 14, GRI-94 /0257.31, EPA 600/R-96-080n, June 1996, p. 2.

[86] The reported emission factor for a dehydrator with a flash tank is 3.57 scf of methane per MMscf throughput compared to the emission factor for a dehydrator without a flash tank, which is 175.10 scf of methane per MMscf throughput. The emission factor for a dehydrator with a flash tank is 98% less than that without a flash tank (175.10 – 3.57 / 175.10 = 0.98). *Id* at Appendix A.

[87] EPA ORD, "Methane Emissions from The Natural Gas Industry," Volume 14, GRI-94 /0257.31, EPA 600/R-96-080n, June 1996. This report estimates an incremental methane emission rate for dehydrators with stripping gas of 670 scf of methane per MMscf throughput. Compared with total emission rates from dehydrators without flash tanks of 175 scf of methane per MMscf throughput, these additional methane emissions from the use of stripping gas can be quite significant (over 3 times that from dehydrator reboiler vent emissions from units without flash tanks).

[88] EPA ORD, "Methane Emissions from The Natural Gas Industry," Volume 15, GRI-94 /0257.33, EPA 600/R-96-080o, June 1996, p. 14. This report estimates an emission factor for gas-assisted glycol pumps at production sites of 992 scf of methane per MMscf throughput, which is over 5 times higher than the emission factor for dehydrators without flash tanks of 175 scf of methane per MMscf throughput (found in Volume 14).

[89] EPA ORD, "Methane Emissions from The Natural Gas Industry," Volume 14, GRI-94 /0257.31, EPA 600/R-96-080n, June 1996, Appendix A.

[90] 75 FR 18608, April 12, 2010. Note, EPA proposed engineering estimates as the means for demonstrating compliance for conventional well completions and conventional well workovers.

1. Existing Federal, State and County Programs to Reduce Methane Emissions from Dehydrators

The following federal, state and county programs demonstrate that mandatory controls for reducing methane emissions are possible. EPA should consider these standards as minimum requirements for regulating sources under the NSPS. Regulations aimed at reducing VOCs and HAPs are relevant to consider because of the corresponding reductions in methane emissions that are achievable through implementation of these control technologies and practices.

Federal NESHAP Requirements

EPA's National Emission Standards for Hazardous Air Pollutants (NESHAP) for Oil and Natural Gas Production Facilities (40 CFR 63 Subpart HH) and for Oil and Gas Transmission and Storage Facilities (40 CFR 63 Subpart HHH) require installation of equipment to either: (1) reduce HAPs from dehydrator vents by 95 percent using either closed-vent control systems or by implementing process modifications; or (2) combust HAPs below 20 ppm_v.[91] These NESHAPs are applicable to production facilities with a throughput floor of 3MMscf/day and to transmission and storage facilities with a throughput floor of 10MMscf/day. These NESHAP requirements are also triggered if total benzene emissions exceed one ton per year. Many of the same technologies used to meet the NESHAP requirements (*e.g.*, installing flash tank separators) are also applicable methane control techniques that EPA should consider as technically feasible and cost-effective options for methane performance standards. In addition to these federal requirements, some states have implemented certain control requirements and operating practices for reducing VOC and HAP emissions from dehydrators that are discussed in more detail below. EPA should also take into account these state program requirements when considering methane performance standards from the oil and gas sector.

Wyoming

Permitting rules in Wyoming address VOC and HAP emissions from dehydration units with a tiered approach that requires tighter controls in the most concentrated development area (the Jonah and Pinedale Anticline Development area). For this area, 98% control efficiency is required for all dehydration unit process vents at all new or modified facilities.[92] The statewide and Concentrated Development Area require that all oil and gas operators must follow one of the two scenarios laid out in guidance for reducing emissions from dehydration units. Under scenario 1, 98% control efficiency is required for all new and modified facilities. Combustion units used can be removed after one year on all units with still vent condensers installed that are under 6 tons per year (tpy). Scenario 2 requires that installation of glycol flash separators and reboiler still vents at all new or modified facilities. If potential uncontrolled VOC emissions are equal to or greater than 8 tpy, 98% control efficiency must be achieved on all units within 30 days of first date of production or upon the date of modification. Combustion units used can be removed after one year on all units with flash separators and still vent condensers installed that are under 8 tpy. All non-condensable still vent and glycol flash separator vapors must be routed to the combustion unit for 98% control of VOC and HAP emissions or used as fuel for process

[91] 66 FR 34548, June 29, 2001.
[92] Wyoming DEQ, C6 S2 O&G Production Facilities Permitting Guidance, March 2010, p. 18.

equipment burners in facilities were a combustion unit is required. When a combustion unit is not required, glycol flash separator vapors must be collected and used as fuel in process equipment burners. Any excess vapors not used may then be vented to the atmosphere.[93]

Colorado

The state of Colorado's air pollution regulations include 90% control efficiency requirements for natural gas dehydrators at oil and gas exploration and production operations, natural gas compressor stations, drip stations or gas processing plants statewide. Any single dehydrator or grouping of dehydrators with VOC emissions exceeding 15 tpy (on a rolling 12-month basis) must meet this control requirement. For groups of dehydrators that exceed the 15 tpy threshold, all single dehydrators over 2 tpy are subject to the 90% control efficiency requirement.[94]

In 2008, Colorado's Air Pollution Control Division proposed a more stringent control strategy for dehydrators. The strategies considered were to increase the required control efficiency from 90% to 98% and to reduce the applicability threshold from the existing 15 tpy down to 2 tpy in the ozone nonattainment area and 5 tpy for the rest of the state. The state also considered requiring optimization of lean glycol pump circulation rates, requiring the installation of flash tank separators and the control of emissions on new dehydration systems, and requiring the use of portable desiccant dehydrators.

Part of the rationale for increasing the control efficiency was that, "[m]any control technologies already in place achieve control efficiencies of at least 98 percent, such as vapor recovery units, enclosed smokeless combustion devices (*e.g.*, thermal vapor incinerators, boilers, or process heaters), and smokeless flares."[95] However, this more stringent approach was not adopted by the state since these additional controls were not needed to demonstrate attainment of the 8-hour ozone standard. In addition, the oil and gas industry believed that the 90% level of control could be achieved using a condenser rather than having to install a combustion device, which would be necessary if the required control efficiency were 98%.[96]

The Colorado Oil and Gas Conservation Commission also regulates VOC emissions from natural gas dehydrators in three counties[97] with high volumes of oil and gas production that are outside of the ozone nonattainment or attainment/maintenance areas. Any dehydrator with a potential to emit (pte) VOC of 5 tpy or greater, that is located within ¼ mile of certain public facilities or areas, must use control devices that can achieve 90% control efficiency and have an appropriate state permit.[98]

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[93] *Id,* 6-7 & 12-13.
[94] Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, XII.H and XVII.D. Separate sections are included in the rules for ozone nonattainment areas or attainment/maintenance areas and for state only requirements but the actual requirements are identical.
[95] Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 RAQC Meeting, Colorado Air Pollution Control Division.
[96] Email communication with Christopher Laplante, Oil & Gas Team Permitting Supervisor, Air Pollution Control Division, Colorado Dept. of Public Health and Environment, October 27, 2010.
[97] Garfield, Mesa & Rio Blanco Counties.
[98] Colorado Code of Regulations, §805 b(2)C, http://www.sos.state.co.us/CCR.

Ventura County, California

In 1994, the Ventura County Air Pollution Control District adopted a rule targeting Reactive Organic Compound (ROC) emissions from glycol regenerator vents. Under the rule, operators can chose from several options that would all achieve a 95% reduction in ROC emissions from glycol regenerator vents. The first option requires the collecting and condensing of all ROC by a condenser/separator system that directs all uncondensed ROC to a vapor recovery/disposal system. The vapor disposal system can use any method with a removal efficiency of at least 95%. The second option under this rule is the use of a flare or incinerator that is operated in a specified manner so as to decrease ROC emissions and the third option allows for any other control mechanism that would achieve the 95% removal efficiency.[99]

2. Available Proven Technologies for Dehydrators

EPA's own Natural Gas STAR program provides evidence that there are many available, technically feasible and cost-effective technologies that can greatly reduce methane emissions from dehydrators. These options include both: (1) technology standards for dehydrators; and (2) improving operating practices to reduce emissions. EPA should, at a minimum, consider the following technologies and operating practices as cost-effective standards for reducing methane emissions from oil and natural gas systems.

Require the Use of Zero Emission Dehydrators
Zero emission dehydrators combine several technologies to virtually eliminate methane emissions from the dehydration process by recovering methane from the still column, eliminating the need for gas strippers and using electricity to power the circulation pumps. Specifically, non-condensable vapors collected from the glycol still column are used as fuel for the reboiler, a water exhauster is used in place of a gas stripper and an electric pump is used to circulate the glycol solution. According to EPA, "[c]apital costs of a zero emissions dehydrator are similar to installing a conventional dehydrator with a thermal oxidizer."[100] The Four Corners Air Quality Task Force report of Oil and Gas Mitigation Options indicated that the zero emission dehydrator could, in fact, be used as a *mandatory* technology in areas experiencing air quality problems and would achieve large reductions in VOC, HAP and methane emissions.[101] According to this same report, "[o]perating and [m]aintenance costs are greater than $1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators" and "EPA estimates the payback to occur in less than a year."[102] EPA should require the use of zero emission dehydrator technology for all new installations.

EPA's Environmental Technology Verification (ETV) program has evaluated the performance of a zero emission dehydrator called the Quantum Leap Dehydrator (QLD). The QLD, manufactured by Engineered Concepts, LLC, uses a series of heat exchangers, condensers,

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[99] Ventura County Air Pollution Control District, Rule 71.5 Glycol Dehydrators, adopted 12/13/94, http://www.vcapcd.org/Rulebook/Rule4.htm.
[100] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 206, "Zero Emissions Dehydrators", http://www.epa.gov/gasstar/documents/zeroemissionsdehy.pdf.
[101] Four Corners Air Quality Task Force Report of Mitigation Options, November 1, 2007, pp. 91-93.
[102] *Id.*

separators and electric pumps to recover still column vapors. In 2003, the ETV program certified certain performance and environmental performance criteria for a QLD unit installed in Brighton, Colorado and did not detect methane concentrations during any of the test periods.[103] The HAP destruction efficiency was calculated at greater than 99.74 ± 0.01 percent.[104] EPA's ETV program was designed to facilitate the use of "innovative or improved environmental technologies through performance verification and information dissemination." According to EPA, "[t]he ETV program goal is to further environmental protection by accelerating the acceptance and use of improved and cost-effective technologies."[105] EPA should therefore consider the zero emission dehydrator as a technically and economically feasible option for all new dehydrator installations.

Require the Use of Solid Desiccant Dehydrators in Cases Where Zero Emission Dehydrators Are Not Feasible

Natural Gas STAR partners have found that solid desiccant dehydrators (using adsorption) reduce methane, VOC, and HAP emissions by 99 percent compared with glycol dehydrators and also have lower operating and maintenance costs.[106] Solid desiccant dehydrator technology uses a drying bed of desiccant tablets to remove water from the produced gas stream. The tablets extract moisture from the gas as it passes through the bed of tablets. A solid desiccant dehydrator operates as a fully enclosed system with essentially no emissions. A small amount of emissions occur when the vessel is opened for maintenance or other reasons (*e.g.*, desiccant tablets that dissolve over time need to be replaced periodically). Solid desiccant dehydrators are very simple devices with no moving parts and no external power supply needs. They are appropriate for use in a wide variety of applications, including for use at remote sites and for portable applications.

The amount of moisture that can be removed from the produced gas stream by a solid desiccant dehydrator is dependent on the type of desiccant used, as well as the temperature and pressure of the gas stream. EPA should consider the latest available desiccant technology when determining the applicability of this technology to all types of new installations. For example, calcium chloride is the most common and the least expensive desiccant but has more limited operating ranges than other desiccants. According to EPA Natural Gas STAR Partners, "calcium chloride can achieve pipeline-quality moisture contents at temperatures below 59^{o}F and pressures above 250 psig."[107] Lithium chloride is a more expensive desiccant but has a much wider operating range (*i.e.*, up to 70^{o}F and above 100 psig). Some desiccants (aside from calcium chloride) can be re-generated and re-used. A cursory review of currently-available desiccant dehydrator technology shows that there are several companies offering units that can effectively operate at high temperatures (*e.g.*, as high as 200^{o}F) and at high pressure (*e.g.*, max allowable working

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[103] ETV Joint Verification Statement, Quantum Leap Dehydrator, pp. S-4 and S-5, available online at http://www.epa.gov/etv/pubs/03_vs_quantum.pdf. The minimum detection limit was 0.1 ppmvd so methane concentrations were < 0.1 ppmvd (or < 0.00004 lb/hr).
[104] *Id* at S-5.
[105] *Id.*
[106] Lessons Learned, Natural Gas STAR Partners, "Replacing Glycol Dehydrators with Desiccant Dehydrators", October 2006, http://www.epa.gov/gasstar/documents/ll_desde.pdf.
[107] *Id.*

pressures as high as 2220 psig) and are marketed for "environmentally sensitive applications."[108] Silica gel type desiccants can be designed to also extract marketable liquid hydrocarbons from the dehydration process.[109] These examples are evidence that EPA must seriously consider solid desiccants as a technically feasible standard for dehydration units.

While replacement cost of the desiccant is slightly higher than the glycol used in a glycol dehydration system (because the desiccants themselves need regular replacement whereas the glycol is re-circulated), this is the only O&M cost for these systems. In a recent Global Methane Initiative presentation, comparison of costs for installation of a solid desiccant dehydrator versus a glycol dehydrator showed slightly *higher* costs for installation, operation and maintenance of a glycol system than for a solid desiccant system.[110] EPA lists desiccant dehydrators as a cost-effective technology with a payback of 1-3 years.[111] This is evidence that EPA should consider this technology to be a cost-effective option for dehydration. CARB already lists the use of desiccant dehydrators as a BMP for oil and gas sources.[112]

EPA should require all new dehydrators to first use zero emission dehydrator technology and use solid desiccant technology in applications where zero dehydrator technology is not feasible. If, after thorough consideration of existing state-of-the art technology, EPA determines that zero emission dehydration and solid desiccant dehydration are not universally applicable, then EPA should require it where possible and also require specific technology standards and operating practices for glycol dehydration units where zero dehydration and solid desiccant dehydration are not technically feasible.

Require Glycol Dehydrators to Use Vapor Recovery Units

Requiring that flash tank separators and other vents be piped to a vapor recovery unit (VRU) will result in less methane emissions vented from the reboiler. The VRU can then increase the recovered gas pressure enough to inject it into a fuel gas system or gathering/sales line. According to a recent proposal by the Colorado Air Pollution Control Division to increase control device efficiencies on dehydrator units from 90% to 98%, "many vapor recovery units and combustion devices already have control efficiencies of at least 98 percent."[113] EPA should

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[108] *See*, e.g., Emerson Process Management's Bettis Molecular Sieve Desiccant Dehydrator For Natural Gas with a regenerable desiccant bed and operating temperature range from -80°F to 200°F, http://www2.emersonprocess.com/siteadmincenter/PM%20Valve%20Automation%20Documents/Bettis/Brochure/MolecularSieve.pdf; *see also* Cameron's Natco Desi-Dri Desiccant Dehydration, "emissions-free" natural gas dehydration system that uses proprietary desiccants and is "environmentally safe and reduces capital costs, as well as operating and compliance costs," http://www.c-a-m.com/Forms/Product.aspx?prodID=fdee24ed-c860-40bb-947a-fb917fcafe92.
[109] http://www.kwintl.com/glycol-dehydrators.html.
[110] Methane to Markets slide presentation, "Production/Processing Best Practices: Natural Gas Dehydrator and Pneumatic Controller Optimization for Methane Emission Reductions", Oil & Gas Subcommittee, Technology Transfer Workshop, January 28, 2009 Monterrey, Mexico, slide 24, http://methanetomarkets.org/documents/events_oilgas_20090127_techtrans_day2_plauchu1_en.pdf.
[111] http://www.epa.gov/gasstar/tools/recommended.html.
[112] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[113] Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 Regional Air Quality Council Meeting, "APCD OZ ISSUE PAPER oil and gas all strategies.doc," Prepared by the Colorado Air Pollution Control Division, Contact: Rose Waldman, available at

require the use of vapor recovery units with control efficiencies of at least 98%, or other technology or operational practice that would achieve a similar or greater reduction in methane emissions. CARB already lists the use of use of vapor recovery units at glycol dehydrators as a BMP for oil and gas sources.[114]

This technology is also an effective means of reducing methane emissions at offshore oil and gas operations. In a paper on offshore platform methane reduction strategies, the authors analyzed offshore oil and gas methane emissions and control strategies to devise an emission reduction strategy for the most significant sources at the lowest cost. The use of vapor recovery units at dehydrators is one of the recommended strategies for reducing methane emissions in offshore applications.[115]

Jatco Incorporated's Jatco Vapor Recovery Unit (JVR) is an example of an available technology designed to recover vapors with use of a Venturi valve. According to manufacturer information, the JVR unit can be used in remote field application with no electrical power requirement and has wide-ranging applications including glycol dehydrators and storage tank vapors.[116] This technology has been successfully applied by an EPA Natural Gas STAR partner in the Denver-Julesburg Basin in Colorado to reduce methane, VOC and BTEX emissions.[117]

Additional benefits of VRUs include the economic benefit of the recovered salable gas as well as reductions in vented VOC and HAP emissions from the reboiler.

Require the Use of Flash Tank Separators For Glycol Dehydrators

Requiring the use of flash tank separators on glycol dehydrators is a cost-effective way to reduce methane emissions. Recovered gas can be recycled and used as a fuel for the reboiler or compressor engine. EPA Natural Gas STAR economic analyses show flash tank separators installed on dehydration units can payback costs in less than one year.[118] Operation of a flash tank can capture approximately 90% of methane entrained by the glycol.[119] EPA should require the use of flash tank separators on all glycol dehydration units. CARB already lists the use of flash tank separators for glycol dehydrators as a BMP for oil and gas sources.[120]

In addition to reduced methane emissions, use of flash tank separators will result in VOC and HAP emissions reductions, as well. The flash tank separator can capture approximately 10%-

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http://www.cdphe.state.co.us/ap/ozone/RegDevelop/IssuePapers/February22-08/APCDOZISSUEPAPEROGdehydrators_000.pdf.

[114] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

[115] Bylin, Carey et al. for Society of Petroleum Engineers, "Designing the Ideal Offshore Platform Methane Mitigation Strategy," 2010, p. 1.

[116] Jatco Inc, http://www.jatcoinc.com/products/jatco-vapor-recovery-unit/jatco-vapor-recovery-unit.

[117] *See*, "Methane Reduction from Natural Gas Dehydration in the DJ Basin," Producers Technology Transfer Workshop, EPA's Natural Gas STAR Program Glenwood Springs, CO September 11, 2007, http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/rocksprings9.pdf.

[118] Lessons Learned, Natural Gas STAR Partners, "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators," October 2006, http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf.

[119] *Id.*

[120] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

90% of the VOCs entrained by the glycol.[121] And in particular, BTEX emission reductions with flash tank separator use can be significant for large dehydrators.[122] Dehydration units that have flash tank separators in combination with a condenser on the reboiler vent result in overall improved efficiency of the condenser.

Require Circulation Rate Adjustment Practices for All Glycol Pumps

Methane emissions from a glycol dehydrator are directly proportional to the amount of glycol circulated through the system; the higher the circulation rate the more methane is vented from the reboiler. Over time, production rates at the wellhead decline and circulation rates designed for the initial well production rate exceed those required for a mature well. According to EPA Natural Gas STAR partners, circulation rates "are often two to three times higher than the level needed to remove water from natural gas," which means methane emissions are two to three times higher than necessary.[123] Both the BLM and CARB list the optimization of circulation rates as a BMP for oil and gas sources.[124] EPA should require operating practices that reduce circulation rates in order to reduce methane emissions. This practice can be implemented without affecting dehydration efficiency and without additional cost to the operator. EPA should require operators to review and adjust glycol circulation rates to optimize efficiency. Operators should also be required to incorporate circulation rate adjustments into regular O&M practices.

Require Glycol Dehydrators to Use Portable Desiccant Dehydrators During Maintenance

During complete shutdowns for maintenance of glycol dehydrators, production wells can either be shut in or vented to the atmosphere. EPA should require the use of portable solid desiccant dehydrators in place of a glycol dehydrator during maintenance to avoid venting of methane to the atmosphere. The State of Colorado has proposed requiring the use of portable desiccant dehydrators at new installations.[125]

Require Installation of BASO® Valves

EPA should require that all new gas dehydrators employ BASO® valve technology to shut-off the gas flow in the event that pilot lights are extinguished (*e.g.*, from high winds, etc.). This is a simple, cost-effective technology that prevents methane emissions that result when the pilot light is extinguished in any air-aspirated burner.

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[121] Lessons Learned, Natural Gas STAR Partners, "Producer and Processor Best Management Practices", July 23, 2008, http://www.epa.gov/gasstar/documents/workshops/2008-tech-transfer/midland7.ppt.

[122] Lessons Learned, Natural Gas STAR Partners, "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators", October 2006, http://www.epa.gov/gasstar/documents/ll_flashtanks3.pdf.

[123] *Id.*

[124] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

[125] Colorado Air Pollution Control Division, Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 RAQC Meeting.

3. Summary Recommendations for Dehydrators

Zero emission dehydrators virtually eliminate methane emissions from the dehydration process. The State of Wyoming's existing requirements for dehydrators and the State of Colorado's recent proposed control strategy for dehydrators are evidence that 98% control of emissions—including methane emissions—from dehydrator units is technically and economically feasible. The fact that solid desiccant dehydrator technology can achieve 99% reduction in methane emissions and the use of flash tank separators and vapor recovery units in glycol dehydration systems can achieve 98% reduction in methane emissions means that EPA should call for nothing less than 98% reduction in methane emissions when considering technology standards and operation practices for this emissions source.

Specifically, EPA should propose the following technology standards and operating practices for dehydration units:

- *Require the Use of Zero Emission Dehydrators*
  EPA should require the use of zero emission dehydrator technology for all new installations.

- *Require the Use of Solid Desiccant Dehydrators in Cases Where Zero Emission Dehydrators Are Not Feasible*
  EPA should require all new dehydrators to first use zero emission dehydrator technology and use solid desiccant technology in applications where zero dehydrator technology is not feasible. Solid desiccant dehydration should reduce methane emissions by 99%. If, after thorough consideration of existing state-of-the art technology, EPA determines that zero emission dehydration and solid desiccant dehydration are not universally applicable then EPA should require it where possible and also specific technology standards and operating practices for glycol dehydration units where zero emission dehydration and solid desiccant dehydration are not technically feasible.

- *Require Glycol Dehydrators to Use Vapor Recovery Units*
  EPA should require the use of vapor recovery units with control efficiencies of at least 98%, or other technology or operational practices that would achieve a similar or greater reduction in methane emissions.

- *Require the Use of Flash Tank Separators*
  EPA should require the use of flash tank separators on all glycol dehydration units to ensure reduction of methane emissions by at least 98%.

- *Require Circulation Rate Adjustment Practices for All Glycol Pumps*
  EPA should require operators to review and adjust glycol circulation rates to optimize efficiency. Operators should also be required to incorporate circulation rate adjustments into regular O&M practices.

- *Require Glycol Dehydrators to Use Portable Desiccant Dehydrators During Maintenance*
  EPA should require the use of portable solid desiccant dehydrators in place of a glycol dehydrator during maintenance to avoid venting of methane to the atmosphere.

- *Require Installation of BASO® Valves*
  EPA should require that all new gas dehydrators employ BASO® valve technology to shut-off the gas flow in the event that pilot lights are extinguished (e.g., from high winds, etc.).

D. Tanks

Onshore production and processing storage tanks and transmission storage tanks are sources of methane emissions from the oil and gas sector. Storage tanks provide for the temporary storage of liquids prior to when produced liquids are moved off-site for processing. Emissions of methane from storage activities occur through several mechanisms: (1) flashing losses that result when pressure is reduced in the tank; (2) working losses that result when filling and emptying of the storage tank occurs; and (3) breathing (or standing) losses that result when the tank gas volume expands and contracts in response to environmental conditions (*e.g.*, changes in temperature and pressure).

According to U.S. Greenhouse Gas Inventory data, storage tank venting accounts for about 5 Bcf—or about 4 percent—of methane emissions from the production sector.[126] These estimates, however, may grossly underestimate actual emissions from this source. According to EPA's recent rulemakings for the Mandatory Reporting of Greenhouse Gases program, several emissions sources are believed to be "significantly underestimated" in the U.S. GHG Inventory (EPA/GRI/Radian, 1996).[127,128] Specifically, EPA identifies crude oil and condensate storage tanks as a source of under-reported emissions where the true magnitude of emissions may be over five times greater than previous estimates. According to EPA, the emissions estimates for these under-reported sources "do not correctly reflect the operational practices of today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[129] EPA includes revised emission factor for all of the underestimated sources except the categories of crude oil and condensate storage tanks and flares, for which "no new reliable data are available."[130] The uncertainty in the degree to which

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[126] Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2007, USEPA, April, 2009, *see* http://www.epa.gov/gasstar/basic-information/index.html#sources.
[127] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.
[128] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 7.
[129] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 23.
[130] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 7, also see Footnote 4: "EPA did consider the data available from two new studies, TCEQ (2009) and TERC (2009). However, it was found that the data available from the two studies raise several questions regarding the magnitude of

storage tank emissions are underestimated is sufficient reason to insist on rigorous performance standards and work practices for this particular category. However, there is even more evidence that the emissions estimates for this and other sources remain uncertain and continue to be greatly underestimated.

A study prepared for the Texas Environmental Research Consortium measured emissions rates from several oil and condensate tanks in Texas and developed average emission factors based on direct measurement of vent gas flow rates.[131] The U.S. GHG Inventory mentions this study but indicates that "[b]ecause of the limited dataset and unexpected jumps in data points which can be attributed to non-flashing emission affects, the United States decided that further investigation would be necessary before updating the inventory emission factor."[132] The study determined "the direct measurement approach to be the most accurate for estimating oil and condensate storage tank emissions at wellhead and gathering sites; however, other, less accurate, approaches appear to be much more commonly used." EPA proposed the use of modeling (using "E&P Tank") to calculate emissions from storage tanks in the GHG Mandatory Reporting Rule. Yet, the TSD for that rulemaking acknowledges significant weaknesses with this approach.[133] And, in fact, the Western Climate Initiative recommended major changes to EPA's proposed reporting requirements for this source category.[134] Due to the uncertainty in the emissions from this source, EPA must commit to careful consideration of this source's contribution to overall emissions of methane from the oil and gas sector and should consider implementation of the best available performance standards and operating practices in order to achieve methane reductions from this important source.

1. <u>Existing State, County and International Programs to Reduce Methane Emissions from Tanks</u>

The following state, county, and international programs demonstrate that mandatory controls for reducing methane emissions are possible. EPA should consider these standards as minimum requirements for regulating sources under the NSPS. Regulations aimed at reducing VOCs and HAPs are relevant to consider because of the corresponding reductions in methane emissions that are achievable through implementation of these control technologies and practices.

Colorado

Colorado has several requirements applicable to condensate tanks or tank batteries in the Denver 8-hour ozone nonattainment area. Any condensate tank or tank battery controlled with a combustion device must be equipped with auto-ignition upon startup at first date of production or

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emissions from tanks and hence were not found appropriate for any further analysis until the issues are satisfactorily understood and/ or resolved by the authors and covered parties."

[131] Hendler A., Nunn J., Lundeen J., McKaskle R., "VOC Emissions from Oil and Condensate Storage Tanks Final Report", April 2, 2009, available online at http://files.harc.edu/Projects/AirQuality/Projects/H051C/H051CFinalReport.pdf.

[132] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3-47.

[133] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 134.

[134] *See*, http://www.westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/.

after any new tank installation or modification.[135] In addition, surveillance systems must be used at all existing condensate tanks with uncontrolled actual emissions over 100 tpy or greater.[136] Air pollution control equipment at new and modified condensate tanks must meet 95% control efficiency requirements for the first 90 days of operation. If compliance with the system-wide limits can be met after initial 90-day period, then the control equipment may be removed.[137]

For the system-wide control strategy, which applies to all condensate tanks greater than 2 tpy of actual uncontrolled VOC, Colorado is using a tiered approach (with tighter controls during the summertime high ozone season) that ratcheted down VOC emissions from condensate tanks starting in 2005 with a 37.5% emission reduction required. All required reductions apply to actual uncontrolled emissions. For May 1, 2010 through April 30, 2011, 85% reductions are required between May 1 and September 30 and 70% reductions are required for October 1 through April 30. For May 1, 2011 through April 30, 2013, 90% reductions are required between May 1 and September 30 and 70% reductions are required for October 1 through April 30.[138] In 2008, the Colorado Air Quality Control Commission considered a 95% system-wide control but decided to defer decisionmaking on that increased requirement at the time.[139,140]

Colorado has an additional state-only, statewide requirement that all condensate tanks with actual uncontrolled VOC emissions greater than 20 tpy must control emissions by 95%. This rule was effective in May 2008.[141]

The Colorado Oil and Gas Conservation Commission also regulates VOC emissions at condensate tanks and crude oil and produced water tanks in three counties[142] with high volumes of oil and gas production that are outside of the ozone nonattainment or attainment/maintenance areas. Any condensate tanks or crude oil and produced water tanks with a potential to emit VOCs of 5 tpy or greater, that are located within ¼ mile of certain public facilities or areas, must use control devices that can achieve 95% control efficiency and have an appropriate state permit.[143]

Wyoming

The state of Wyoming controls flashing emissions from tanks with statewide requirements and more stringent requirements for the Concentrated Development Area and the Jonah and Pinedale Anticline Development Area. Under these rules, "all vapor streams containing VOC or HAP components from all storage tanks (*e.g.*, oil, condensate, produced water with oil or condensate carryover) and all separation vessels (*e.g.*, gun barrels, production and test separators, production

[135] CDPHE, Colorado Regulation 7, XII.C.1.e.
[136] *Id*, XII.C.1.f.
[137] *Id,* XII.D.1.
[138] *Id*, XII.D.2.
[139] *Id,* p. 96.
[140] The goal of the 2008 rulemaking was to approve a plan that shows modeled attainment of the 8-hour ozone standard; 95% system-wide reductions for condensate tanks were was not necessary under the state's modeling scenarios.
[141] Colorado Regulation 7, XVII.C.
[142] Garfield, Mesa & Rio Blanco Counties.
[143] Colorado Code of Regulations, 2 CCR 404-1 "Practice and Procedure," §805 b(2)A & B, http://www.sos.state.co.us/CCR.

and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility which are or may be vented to the atmosphere shall be considered."[144] The statewide requirements for new facilities or modified facilities with new and existing flashing emissions require 98% control when flashing emissions are equal to or greater than 10 tpy VOC.[145] In the Concentrated Development Area the requirements are more stringent, with all new multiple well facilities and modified facilities with new or existing flash emissions required to meet 98% control for flashing emissions, regardless of annual VOC emissions. For single new well facilities or single modified well facilities in this area, any flashing emissions equal to or greater than 8 tpy VOC must be controlled by 98%.[146] For the Jonah and Pinedale Anticline Development Area the rules are even more stringent, requiring that all new or modified facilities apply 98% controls for flash emissions.[147]

Wyoming also has a 98% VOC control efficiency requirement that applies to the Concentrated Development Area and the Jonah and Pinedale Anticline Development area. Under both sets of requirements new and modified facilities must control VOC and HAP emissions from all active produced water tanks by 98%.[148] Open-top or blowdown tanks are not allowed to be used as active produced water tanks but can be used during emergency or upset conditions, in which case the 98% control requirements does not apply.[149]

Montana

Montana's requirements to control VOC emissions from wellhead assemblies, dehydrators and tanks also result in methane emissions reductions at these sources. The state's rules require that vented gas at larger sources (*i.e.*, PTE > 15 TPY) be captured and routed to: (1) a gas pipeline; (2) a smokeless combustion device (equipped with an electronic ignition device or a continuous burning pilot system) operating at a 95% or greater control efficiency; or (3) an air pollution control device with equal or greater control efficiency than a smokeless combustion device.[150]

India

A planned project in India at the Uran oil and natural gas processing plant, operated by the Oil & Natural Gas Corporation, would install vapor recovery units on storage tanks. The new units are expected to be operational by December 2010.[151]

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[144] Wyoming DEQ, C6 S2 O&G Production Facilities Permitting Guidance, March 2010, p. 5.
[145] *Id.*
[146] *Id,* 11.
[147] *Id*, 18.
[148] The only the difference between these 2 sets of requirements is that the CDA rules are slightly less stringent for new single well facilities, where 98% control efficiency is required within 60 days of first date of production at sites where 98% control of flashing emissions is required.
[149] Wyoming DEQ, March 2010, 16 & 20.
[150] Montana Administrative Rules §17.8.1711, "Oil or Gas Well Facilities Emission Control Requirements," April 7, 2006. http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711.
[151] Methane to Markets, Oil & Gas Methane Reduction Project Opportunity, Oil & Natural Gas Corporation, Uran Oil and Natural Gas Processing Plant, http://www.methanetomarkets.org/projects/projectDetail.aspx?ID=1146.

Ventura County, California

The Ventura County Air Pollution Control District crude oil production and separation rule applies to equipment used in the production, gathering, storage, processing, and separation of crude oil and natural gas. The requirements for storage tanks under this rule require that vapor recovery systems be installed and meet removal efficiencies of 90% for reactive organic compounds, or "[a] system which directs all vapors to a fuel gas system, a sales gas system, or to a flare that combusts reactive organic compounds" must be in place.[152]

Ventura County also has a rule for the storage that applies to any equipment used to store crude oil or ROC liquids with a modified Reid vapor pressure greater than 0.5 psia. These rules include specifications for storage tanks based on their capacities, with requirements for vapor loss control devices, such as the use of an external floating roof, an internal floating roof, or a vapor recovery system. An acceptable vapor loss control device can also be any other system that has a control efficiency of 95% for ROC.[153]

2. Available Proven Technologies for Tanks

EPA's own Natural Gas STAR program provides evidence that vapor recovery units are a technically feasible and cost-effective technology that can reduce methane emissions by at least 95% from storage tanks. EPA should consider vapor recovery units as a cost-effective technology for reducing methane emissions from oil and natural gas systems.

Require the Use of Vapor Recovery Units With at least 98% Control Efficiency for All New Crude Oil and Condensate Storage Tanks

Vapor recovery units are relatively simple systems that can recover over 95% of vapors for sale or for use as fuel on-site. According to EPA, "vapor recovery can provide generous returns due to the relatively low cost of the technology."[154] As is evident by the longstanding local requirements in Ventura County, California and in the newer state regulations in Colorado, Wyoming and Montana, installations of vapor recovery units (VRUs) on all new crude oil and condensate tanks can easily be expected to achieve an efficiency of 95 percent.

EPA should investigate the feasibility of requiring even higher control efficiencies (*e.g.*, 98%) in line with the requirement in Wyoming for controlling VOC emissions from produced water tanks. In fact, Colorado has proposed 98% control of vapors from dehydrator VRUs, indicating that "many vapor recovery units and combustion devices already have control efficiencies of at least 98 percent."[155]

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[152] Ventura County Air Pollution Control District, Rule 71.1- Crude Oil Production and Separation, last revised 6/16/92, http://www.vcapcd.org/Rulebook/Rule4.htm.

[153] Ventura County Air Pollution Control District, Rule 71.2- Storage of Reactive Organic Compound Liquids, last revised 9/26/89, http://www.vcapcd.org/Rulebook/Rule4.htm.

[154] Lessons Learned, Natural Gas STAR Partners, "Installing Vapor Recovery Units on Crude Oil Storage Tanks", October 2006, http://www.epa.gov/gasstar/documents/ll_final_vap.pdf.

[155] Draft Oil and Gas Ozone Reduction Strategy – Presented at February 26, 2008 Regional Air Quality Council Meeting, "APCD OZ ISSUE PAPER oil and gas all strategies.doc", Prepared by the Colorado Air Pollution Control Division, Contact: Rose Waldman, available online at

The vapor recovery unit industry has seen recent advances in technology. In addition to so-called "conventional" vapor recovery units (*e.g.*, rotary compressor type systems and newer scroll compressors) there are other technologies evolving that may make VRUs even more cost effective for new installations. Namely, Vapor Jet technology[156] and Venturi ejector vapor recovery units (EVRU™)[157] both have no moving parts and have shown to be effective in specific applications with reduced O&M costs.[158] Vapor recovery towers (VRT) include a separation vessel that insulates the vapor recovery unit from gas surges and provides for stabilized pressure to allow more effective VRU performance.[159] These cost-saving and performance-enhancing technology advancements further support the universal use of vapor recovery technology to effectively control methane emissions from crude oil and condensate storage tanks.

EPA's Environmental Technology Verification (ETV) program has evaluated the performance of Comm Engineering USA's environmental vapor recovery unit (EVRU™). The EVRU™ is a closed loop system designed to reduce or eliminate emissions of GHGs (methane and CO_2), VOCs, and HAPS. The test EVRU™ was used to collect low-pressure vent gas from condensate storage tanks. The ETV program certified certain performance and environmental performance criteria for an EVRU™ unit installed in McAllen, Texas.[160] The EPA's ETV program was designed to facilitate the use of "innovative or improved environmental technologies through performance verification and information dissemination." According to the EPA, "[t]he ETV program goal is to further environmental protection by accelerating the acceptance and use of improved and cost-effective technologies."[161] EPA should therefore consider the venturi-type EVRU™ as a technically and economically feasible option for all new tank installations.

In addition to reducing methane, vapor recovery units also capture HAPs and, according to EPA, "can reduce operator emissions below actionable levels specified in Title V of the Clean Air Act."[162]

Methane emissions also occur when methane and VOCs flash or evaporate into the air that is displaced during the loading process. EPA should require that all new installations include the use of a recycle line to recover gas from condensate loading operations that use mobile tanks (*e.g.*, trucks or railroad). Recovered gas can then either be sent to a sales line or used for lease

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http://www.cdphe.state.co.us/ap/ozone/RegDevelop/IssuePapers/February22-08/APCDOZISSUEPAPEROGdehydrators_000.pdf.
[156] Patented technology by Hy-Bon Engineering.
[157] Patented technology by COMM Engineering.
[158] *See, e.g.*, Lessons Learned, Natural Gas STAR Partner Presentation, "Vapor Recovery Tower/VRU Configuration", Producers Technology Transfer Workshop, Long Beach, CA, August 21, 2007, http://www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf.
[159] Methane to Markets Presentation, Reducing Methane Emissions With Vapor Recovery on Storage Tanks, January 28, 2009, Monterrey, Mexico, http://methanetomarkets.org/documents/events_oilgas_20090127_techtrans_day2_richards_en.pdf.
[160] ETV Joint Verification Statement, Quantum Leap Dehydrator, pp. S-4 and S-5, available online at http://www.epa.gov/etv/pubs/03_vs_quantum.pdf. The minimum detection limit was 0.1 ppmvd so methane concentrations were < 0.1 ppmvd (or < 0.00004 lb/hr).
[161] *Id.*
[162] Lessons Learned, Natural Gas STAR Partners, "Installing Vapor Recovery Units on Crude Oil Storage Tanks", October 2006, http://www.epa.gov/gasstar/documents/ll_final_vap.pdf.

fuel. A vapor recovery line and the appropriate connections should be designed to attach the line to the storage tank or a VRU. This operating practice has been shown to be cost-effective, particularly when the recovered gas is sent to a sales or fuel line.[163] This practice will also result in reduced VOC and HAP emissions.

Gas recovery is possible at any gas gathering station and processing plant that frequently removes condensed liquids from its upstream gathering lines. In these situations, recovering the flash gas from pressurized liquid storage tanks prior to atmospheric storage can reduce emissions and add more gas to the sales line. EPA should require this practice, where applicable. For example, systems where pressurized condensate is collected from "pigging" operations and stored in atmospheric tanks (*i.e.*, storage tanks receiving condensate removed from launching/receiving pigging operations) should include vapor recovery controls to reduce vented emissions.[164]

This technology is also an effective means of reducing methane emissions at offshore oil and gas operations. In a paper on offshore platform methane reduction strategies, the authors analyzed offshore oil and gas methane emissions and control strategies to devise an emission reduction strategy for the most significant sources at the lowest cost. The use of vapor recovery units for storage tanks is one of the recommended strategies for reducing methane emissions in offshore applications.[165]

3. Summary Recommendations for Tanks

EPA should implement the following for all new storage tank installations:

- *Require the Use of Vapor Recovery Units With at least 98% Control Efficiency for All New Crude Oil and Condensate Storage Tanks*
  EPA should require that all new installations include a VRU with a 98% control efficiency and should require the use of a recycle line to recover gas from condensate loading operations that use mobile tanks (*e.g.*, trucks or railroad). EPA should also require recovery of gas from pipeline pigging operations.

E. Wells

Methane emissions from well venting (*e.g.*, from liquids unloading, well completion and well workover) are a significant source of emissions from the natural gas production sector. According to U.S. Greenhouse Gas Inventory data, well venting and flaring account for about 7 Bcf—or just over 5 percent—of methane emissions from the production sector. These estimates,

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[163] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 503, "Recycle Line Recovers Gas During Condensate Loading", http://www.epa.gov/gasstar/documents/recyclelinerecovers.pdf.
[164] *See*, e.g., EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 507, "Recover Gas From Pipeline Pigging Operations", October 2004, http://www.epa.gov/gasstar/documents/pigging.pdf and Lessons Learned, Natural Gas STAR Partner Presentation, "Efficient Pigging of Gathering Lines", Processor Technology Transfer Workshop, April 22, 2005, http://www.epa.gov/gasstar/documents/pigging_lines.ppt.
[165] Bylin, Carey et al. for Society of Petroleum Engineers, "Designing the Ideal Offshore Platform Methane Mitigation Strategy," 2010, p. 1.

however, may grossly underestimate actual emissions from this source. According to EPA's recent rulemakings for the Mandatory Reporting of Greenhouse Gases program, several emissions sources are believed to be "significantly underestimated" in the U.S. GHG Inventory (EPA/GRI/Radian, 1996).[166,167] Specifically, EPA identifies well venting for liquids unloading, gas well venting during well completions and gas well venting during well workovers as three sources of under-reported emissions. According to EPA, the emissions estimates for these sources "do not correctly reflect the operational practices of today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[168] EPA includes revised emission factors for all of these underestimated well venting sources, as follows: (1) an emission factor for well venting for liquids unloading that is 11 times higher; (2) an emission factor for venting during completions that is 35 times higher for conventional wells and almost 9,000 times higher for unconventional wells; and (3) an emission factor for gas well venting during well workovers that is 3,500 times higher for unconventional wells.[169] Overall, the revisions to these and the revised factor for centrifugal compressor wet seal degassing venting results in a more than 100% increase in estimated emissions from the oil and gas production sector.[170] These enormous underestimates, alone, are enough of a reason to insist on rigorous performance standards and work practices for these particular categories. However, there is even more evidence that the emissions estimates for these and other sources remain uncertain and continue to be greatly underestimated.

An area of particular uncertainty appears to be gas well completions and well workovers. As EPA notes in the preamble to the proposed mandatory reporting rule:

> [N]o body of data has been identified that can be summarized into generally applicable emissions factors to characterize emissions from these sources [(i.e., from well completion venting and well workover venting)] in each unique field. In fact, the emissions factor being used in the 2008 U.S. GHG Inventory is believed to significantly underestimate emissions based on industry experience as included in the EPA Natural Gas STAR Program publicly available information (http://www.epa.gov/gasstar/). In addition, the 2008 U.S. GHG Inventory emissions factor was developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country.[171]

[166] EPA/GRI (1996) Methane Emissions from the Natural Gas Industry. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.
[167] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 7.
[168] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 23.
[169] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 8, Table 1.
[170] *Id.* at 9.
[171] 75 FR 18621, April 12, 2010.

As noted, there is believed to be a significant underestimate in emissions from well completions based on industry experience as reported through EPA's Natural Gas STAR program. The 2008 U.S. GHG Inventory emphatically states that "[n]atural gas well venting due to unconventional well completions and workovers, as well as conventional gas well blowdowns to unload liquids have already been identified as sources for which Natural Gas STAR reported reductions are significantly larger than the estimated inventory emissions."[172] And EPA has indicated that "[p]resently, [reduced emission completions (REC)] reductions reported in the Natural Gas STAR body of work is larger than well completion venting in the inventory on an annual basis."[173] Specifically, the U.S. GHG Inventory is based on an emission factor of a little over three thousand standard cubic feet (3 Mcf) per gas well drilled and completed.[174] Yet, Natural Gas STAR program partner experience shows several cases where emission factors were thousands of times higher than that shown in the 2008 inventory. Examples include: (1) a BP project employing green completions at 106 wells and reporting 3,300 Mcf of gas recovered per well;[175] (2) a Devon Barnett Shale project employing green completions at 1,798 wells between 2005 and 2008 and reporting 6,300 Mcf of gas recovery per well;[176] and (3) a Williams project employing green completions at 1,064 wells in the Piceance Basin reporting 22,000 Mcf of gas recovered per well.[177] All of these examples include gas recovery estimates more than 1,000 times higher than the 3 Mcf of gas per well estimated in the U.S. GHG Inventory for 2008. These data are consistent with the unconventional gas well completion and workover data presented in EPA's TSD for the MRR revisions (April 2010). Specifically, the technical support document includes four examples from the Natural Gas STAR program with gas completion rates of 6,000 Mcf, 10,000 Mcf, 700 Mcf and 20,000 Mcf per completion.[178] EPA used an average of these four data points for its emission factor for this source (*i.e.*, 9,175 Mcf/completion). Using this factor resulted in estimated emissions from completions and well workover from conventional and unconventional wells of 120 billion standard cubic feet (Bcf). In comparison, the U.S. GHG Inventory reports emissions of just 0.1 Bcf of gas from drilling and well completions.[179]

More generally, Natural Gas STAR partners reported recovering between 7 and 12,500 Mcf (average of 3,000 Mcf) of natural gas from each cleanup with the potential for an estimated 25

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[172] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, p. 3-47.
[173] *See* "Environmental Defense Fund (EDF) Questions & USEPA Answers – June 1, 2010" posted to the Docket for EPA's MRR revisions to Subpart W on June 2, 2010, Docket ID EPA-HQ-OAR-2009-0923-0070.
[174] Table A- 118: 2008 Data and CH_4 Emissions (Mg) for the Natural Gas Production Stage, p. A-144, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006.
[175] *See* Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/green_c.pdf, slide 11.
[176] *See* attached 2009 workshop presentation by Devon, slides 3 and 13. 6,300 Mcf = 11.4 Bcf / 1,798 wells.
[177] *See* Natural Gas STAR Program Recommended Technologies and Practices for Wells at http://www.epa.gov/gasstar/tools/recommended.html, and specifically http://www.epa.gov/gasstar/documents/vincent.pdf, slide 14.
[178] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, Appendix B on pp. 79-82.
[179] *See* Table A-125: CH_4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg. (2.05 Gg * 0.052 ft^3/g = 0.1 Bcf)

Bcf of natural gas recovery from green completions annually in 2005 compared with the annual U.S. GHG Inventory total for "Drilling and Well Completion" of just 0.1 Bcf in 2008.[180,181] And more recently, EPA's Natural Gas STAR program attributed 45 Bcf of gas to reduced emissions completions (RECs) in 2008 (representing 50 percent of EPA's Natural Gas STAR program's annual total reductions).[182] If, in fact, the emission factor for well completions is at least 1,000 times higher than what is reported in the U.S. GHG Inventory (*e.g.*, if it is at least 3,000 Mcf instead of 3 Mcf) this would add 100 Bcf to the total estimated emissions from natural gas systems, raising the total from 240 Bcf to 340 Bcf in 2008 (a 40% increase).[183]

A New York Times article published on October 15, 2009, reports that EPA is currently reviewing and revising methane emissions from U.S. gas wells. According to the article:

> An E.P.A. review of methane emissions from gas wells in the United States strongly implies that all of these figures may be too low. In its analysis, the E.P.A. concluded that the amount emitted by routine operations at gas wells—not including leaks like those seen near Franklin—is 12 times the agency's longtime estimate of nine billion cubic feet. In heat-trapping potential, that new estimate equals the carbon dioxide emitted annually by eight million cars.[184]

In fact, the TSD for the April 2010 MRR includes an estimate of 120 Bcf for U.S. completion and workover venting. As previously discussed, this estimate is based on an emission factor of 9,175 Mcf per completion or workover. Given the sparse data (4 data points) and the enormously wide range of potential emission factor values from this source (ranging from 700 to 20,000 Mcf) even the recently revised estimates may very well continue to underestimate emissions from this source.

The statistical representation of the U.S. GHG Inventory data includes a 95% range within which emissions from this source category are likely to fall for the year 2008. This range, for Natural Gas Systems, includes a lower bound of -24% and an upper bound of +43%.[185] As noted in the uncertainty analysis, "[t]he heterogeneous nature of the natural gas industry makes it difficult to sample facilities that are completely representative of the entire industry."[186] And as a result, basing an emission factor on only a few "representative" sources when considering the highly

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[180] *See* http://www.epa.gov/gasstar/documents/green_c.pdf, slides 9 and 5.

[181] *See* Table A-125: CH_4 Emission Estimates from the Natural Gas Production Stage Excluding Reductions from the Natural Gas STAR Program and NESHAP regulations (Gg), p. A-151, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006. Drilling and Well Completion (2008) = 2.05 Gg.

[182] *See* 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50% are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[183] *See* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-38 CH4 Emissions from Natural Gas Systems (Gg), p. 3-45. Total emissions in Bcf: 4,591 Gg * 0.052 ft^3/g = 240 Bcf.

[184] *See* www.nytimes.com/2009/10/15/business/energy-environment/15degrees.html#.

[185] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, Table 3-41, p. 3-46.

[186] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008 (April 2010) U.S. EPA # 430-R-10-006, Chapter 3, p. 3-46.

variable rates measured among these sources, results in a potentially high degree of uncertainty as reflected in the reported uncertainty range.

We are hopeful that the EPA-acknowledged discrepancies between the inventory emissions reported to-date and the Natural Gas STAR reported reductions and the high degree of uncertainty in both of these data sources will be reconciled with a rigorous reporting rule for the oil and gas sector and, in particular, for vented emissions from wells. We also hope that EPA will employ rigorous performance standards for this critical source that is likely a much more significant source of emissions than what is reflected in the U.S. GHG inventory.

It is worth noting that direct measurement of emissions from well venting for liquids unloading as well as during unconventional well completions and well workovers is possible as a means to accurately demonstrate compliance with performance standards established by EPA. EPA proposed direct measurement methods for determining reported emissions under the Mandatory Reporting Rule (MRR) for these source types.[187]

1. Existing State Programs to Reduce Methane Emissions from Wells

The following state programs demonstrate that mandatory controls for reducing methane emissions are possible. EPA should consider these standards as minimum requirements for regulating sources under the NSPS. Regulations aimed at reducing VOCs and HAPs are relevant to consider because of the corresponding reductions in methane emissions that are achievable through implementation of these control technologies and practices.

Colorado

The Colorado Oil and Gas Conservation Commission requires that green completions be installed at all wells in the state that meet a threshold requirement, except in cases where green completions are not technically or economically practical. Green completions are also not required on exploratory wells. "Green completion practices are required on oil and gas wells where reservoir pressure, formation productivity, and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater."[188] Sand traps, surge vessels, separators and tanks must be used during flowback and cleanout operations, with a few exceptions. The aforementioned control devices must be used when the well effluent containing more than ten barrels per day of condensate or within two hours after first encountering hydrocarbon gas of salable quality. With this process, sand, hydrocarbon liquids, water, and gas are safely separated to ensure that the, "salable products are efficiently recovered for sale or conserved and that non-salable products are disposed of in a safe and environmentally responsible manner."[189] If green completions are deemed not feasible, then the

[187] 75 FR 18608, April 12, 2010. Note, EPA proposed engineering estimates as the means for demonstrating compliance for conventional well completions and conventional well workovers.
[188] Colorado Code of Regulations, 2 CCR 404-1 "Practice and Procedure," §805 b(3)B, http://www.sos.state.co.us/CCR.
[189] *Id.*

operator must use other BMPs in order to minimize emissions, such as limiting the amount of flaring and venting.[190]

Wyoming

As per Wyoming's oil and gas production facilities permitting guidance, all operators must submit permit applications that apply best management practices for well completions or re-completions. The permits completed for the Jonah and Pinedale Anticline Development Area are the models to be used. The Wyoming Air Quality Division provides a sample well completion or green completion permit. The permits state: "The operator shall follow the operational plan for Best Management Practices described in the application for this permit to eliminate to the extent practicable emissions of volatile organic compounds and hazardous air pollutants associated with flaring and venting of hydrocarbon fluids recovered during well completion/re-completion activities."[191] Conditions under which it is unacceptable to send gas to the flare are listed in this permit. The permits also must include monitoring, recordkeeping, notification and reporting requirements. The Air Quality Division's Well Completion Emission Spreadsheet must be used to calculate estimates of VOC, total HAPs, NO_X and CO.[192]

Montana

Montana's requirements to control VOC emissions from wellhead assemblies also result in methane emissions reductions at these sources. The state's rules require that vented gas at larger sources (i.e., PTE > 15 TPY) be captured and routed to: (1) a gas pipeline; (2) a smokeless combustion device (equipped with an electronic ignition device or a continuous burning pilot system) operating at a 95% or greater control efficiency; or (3) an air pollution control device with equal or greater control efficiency than a smokeless combustion device.[193]

2. Available Proven Technologies for Wells

EPA's own Natural Gas STAR program provides evidence that there are many available, technically feasible and cost-effective technologies that can greatly reduce methane emissions from wells. These options include both: (1) technology standards for wells; and (2) improving operating practices to reduce emissions. EPA should, at a minimum, require the following technologies and operating practices as part of its revised NSPS for oil and natural gas systems.

Require the Use of Reduced Emission Completions or Green Completions

During a reduced emission completion (REC) or "green completion" the produced natural gas from a well completion or well workover is recovered for salable use instead of being vented to the atmosphere (or flared). Produced gas condensate can also be recovered. This method of

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[190] *Id.,* §805 b(3)C & D.
[191] "Example Well Completions ("Green Completions") Permit," Wyoming Department of Environmental Quality, March 2010, p. 1.
[192] *Id.*
[193] Montana Administrative Rules §17.8.1711, "Oil or Gas Well Facilities Emission Control Requirements," April 7, 2006. http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711.

reducing methane emissions during gas production has been proven to be cost-effective by partners in EPA's Natural Gas STAR program for over five years.[194] RECs require additional equipment to convert the otherwise-vented gas to salable gas. Additional portable equipment is required and may include tanks, portable separators, sand traps, and portable gas dehydration devices. The equipment would be moved from well to well, as needed. Even with the additional capital costs for this equipment, EPA Natural Gas STAR partners report payback periods of less than a year for reduced emission completions.[195] EPA Natural Gas STAR partners also report recovering up to 89% of total gas produced during well completions and workovers (average of 53%) from high-pressure wells.[196] And, in fact, at least one Natural Gas STAR partner has reported 100% recovery of completion gas.[197] Other, more generalized, estimates of methane reduction efficiency based on EPA's Natural Gas STAR partner data are around 70% for green completions.[198] Certainly, higher efficiencies can be expected from the best available technology and design. Technology advances have also made recovery of gas from low-pressure wells possible. For example, the use of portable compressors can be used when the reservoir pressure is too low to enter the gas sales line.[199]

EPA should require the use of reduced emission completions for all new wells unless deemed unsafe, as demonstrated and documented by the operator. EPA should also require 90%, or better, recovery. Both the BLM and CARB list green completions as a BMP for oil and gas sources.[200] This proven, best management practice should be required for all new wells in order to achieve greater emission reductions.

EPA should also require the use of portable desiccant dehydrators to support green completions. RECs can employ solid desiccant dehydrators that are brought on site to process vented gas (from well completions and workovers) before sending it to the sales line.

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[194] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 703, "Green Completions", September 2004, http://www.epa.gov/gasstar/documents/greencompletions.pdf and Lessons Learned, Natural Gas STAR Partners, "Reduced Emission Completions (Green Completions)", October 26, 2005, http://www.epa.gov/gasstar/documents/green_c.pdf and "Reducing Methane Emissions During Completion Operations", 2006 Natural Gas STAR Annual Implementation Workshop, Houston, TX, October 24, 2006, http://www.epa.gov/gasstar/documents/vincent.pdf and Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Production Wells: Reduced Emission Completions", May 11, 2010, http://epa.gov/gasstar/documents/workshops/farmington-2010/08_recs_farmington_nm_final.pdf.

[195] Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Production Wells: Reduced Emission Completions", May 11, 2010, http://epa.gov/gasstar/documents/workshops/farmington-2010/08_recs_farmington_nm_final.pdf.

[196] Lessons Learned, Natural Gas STAR Partners, "Reduced Emission Completions (Green Completions)", October 26, 2005, http://www.epa.gov/gasstar/documents/green_c.pdf.

[197] See Williams Production RMT, Piceance Basin Operations, "Reducing Methane Emissions During Completion Operations", 2006 Natural Gas STAR Annual Implementation Workshop, Houston, TX, October 24, 2006, http://www.epa.gov/gasstar/documents/vincent.pdf.

[198] Robinson, D.R., Fernandez, R., Kantamaneni, R. K., "Methane Emissions Mitigation Options in the Global Oil and Natural Gas Industries, Table 2, http://www.coalinfo.net.cn/coalbed/meeting/2203/papers/naturalgas/NG020.pdf.

[199] Lessons Learned, Natural Gas STAR Partners, "Reducing Methane Emissions from Production Wells: Reduced Emission Completions", May 11, 2010, http://epa.gov/gasstar/documents/workshops/farmington-2010/08_recs_farmington_nm_final.pdf.

[200] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

In addition to reducing methane emissions, RECs produce an additional revenue stream from the recovery of produced natural gas and gas liquids. RECs also result in less solid waste and water pollution and safer operating conditions.

Require the Installation of Plunger Lift Systems in Gas Wells to Reduce Methane Emissions From Blowdown Operations

Venting of a mature well to the atmosphere (well blowdown) in order to remove accumulated fluids can be a significant source of methane emissions. Instead of venting gas wells to force out accumulated well bore fluids, a plunger lift uses the well's energy to efficiently push the fluids out of the well. According to EPA, plunger lift systems are a cost-effective alternative to other lift technologies and to well blowdowns and "can significantly reduce gas losses, eliminate or reduce the frequency of future well treatments, and improve well productivity."[201] EPA lists this technology as having a less than one-year payback.[202] Since there are certain technical feasibility considerations for these systems (*e.g.*, the well shut-in pressure has to be sufficiently higher than the sales line pressure), EPA should require the use of plunger lift systems at all gas wells unless the operator can adequately demonstrate that the well will not operate with sufficient shut-in pressure or production rate to be able to use such a system. EPA should also review the feasibility of requiring the use of pumpjacks and foaming agents when there is insufficient build-up in reservoir pressure to operate a plunger lift system and the use of velocity tubing strings for wells operating with higher reservoir pressure.[203]

Use of the latest information technology (*e.g.*, online data management, satellite communications, etc.) can help reduce management costs (*e.g.*, operator visits) of these systems and help optimize operational practices. In fact, one partner's experience is that "[t]echnology is only a piece of the solution—most significant recent reductions are due to revised operational practices."[204] This partner reported an over 80% reduction in venting.[205] EPA should require the installation of automated well monitoring systems to help optimize plunger lift and blowdown operations. "Smart Automation" systems monitor well production parameters (*e.g.*, pressure, flow rate, plunger velocities, etc.) and use remote telemetry coupled with site-specific operational data to improve well and venting performance. These types of automated systems have enabled significant reductions in gas venting volumes along with production improvements.[206] The BLM lists the use of "Smart Automation" systems as a BMP.[207] Other operational practices include well-specific practices such as optimizing well blowdown times by

[201] Lessons Learned, Natural Gas STAR Partners, "Installing Plunger Lift Systems in Gas Wells", October 2006, http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.
[202] *See* http://www.epa.gov/gasstar/tools/recommended.html.
[203] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet Nos. 706, 707, and 704 "Use Foaming Agents", "Install Pumpjacks on Low Water Production Gas Wells" and "Install Velocity Tubing Strings", http://www.epa.gov/gasstar/documents/usefoamingagents.pdf , http://www.epa.gov/gasstar/documents/gaswells.pdf and http://www.epa.gov/gasstar/documents/installvelocitytubingstrings.pdf.
[204] EPA Natural Gas STAR Presentation, "Plunger Well Vent Reduction Project, G.P. (Skip) Desaulniers, BP, 2006 Natural Gas Star Workshop, http://www.epa.gov/gasstar/documents/desaulniers.pdf.
[205] *Id. See* Southern San Juan Quarterly Vent Volumes (slide 16).
[206] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 709, "Gas Well "Smart" Automation System", http://www.epa.gov/gasstar/documents/smart_automation.pdf.
[207] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov.

monitoring well flow conditions.[208] EPA should require all operators to develop an operational plan, based on the above practices, for managing the plunger lift systems so as to minimize venting.

Other benefits of plunger lift installations include gas savings from avoided blowdowns as well as increased gas production following plunger lift installations. According to EPA, benefits from increased gas production are "well- and reservoir-specific and will vary considerably."[209] EPA Natural Gas STAR partners have reported reductions in other air pollutants, as well, with installation of plunger lift technology.[210] Both the BLM and CARB list the installation of plunger lifts as a BMP for oil and gas sources.[211] Wyoming also has a BMP that requires VOC and HAP emissions from manual and automated blowdown and venting episodes be minimized to the maximum extent practicable.[212]

Require the Installation of Downhole Separator Pumps, Where Applicable

Downhole separator pumps, or hydrocyclones, are used for gas-liquid separation. The pumps are installed upon well completion or well workover and are designed to separate gas from water below the surface and then inject the water into a lower lying aquifer for disposal while sending the methane gas to the surface.[213] Use of these pumps eliminates methane emissions from produced water storage. EPA should require the installation of downhole separator pumps in applications where there is a lower lying water disposal aquifer.

Require Mud Degassing Vents Be Routed to a Vapor Recovery Unit

Mud degassing systems are used to remove entrained formation gas from the drilling mud (drilling fluid) to maintain higher mud density for well control. Drilling mud degassing units extract entrained gas from the mud at the surface and vent this gas directly into the atmosphere. EPA should require that these vents be routed to a vapor recovery unit to reduce methane emissions.

A recent paper on offshore platform methane reduction strategies analyzed offshore oil and gas methane emissions and control strategies and devised an emission reduction strategy for the most significant sources at the lowest cost. Using a vapor recovery unit to capture mud degassing emissions is one of the recommended strategies for reducing methane emissions in offshore applications.[214]

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208 *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 708, "Gas Well Unloading Time Optimization", http://www.epa.gov/gasstar/documents/unloading_time508.pdf
209 Lessons Learned, Natural Gas STAR Partners, "Installing Plunger Lift Systems in Gas Wells", October 2006, http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.
210 ExxonMobil reported that their plunger lift system in the Big Piney Field in Wyoming "reduced the venting of ethane (6 percent by volume), C3 hydrocarbons + VOCs (5 percent), and inerts (2 percent)." *Id.*
211 U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
212 Wyoming DEQ, C6 S2 O&G Production Facilities Permitting Guidance, March 2010, 10, 17 & 21.
213 *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 705, "Install Downhole Separator Pumps", http://www.epa.gov/gasstar/documents/installdownholeseparatorpumps.pdf.
214 Bylin, Carey et al. for Society of Petroleum Engineers, "Designing the Ideal Offshore Platform Methane

3. Summary Recommendations for Wells

EPA should implement the following technology standards and operating practices for all new wells:

- *Require the Use of Reduced Emissions Completions or Green Completions*
  EPA should require the use of reduced emission completions for all new wells unless deemed unsafe, as demonstrated and documented by the operator. EPA should also require 90%, or better, recovery. EPA should also require the use of portable desiccant dehydrators to support green completions.

- *Require the Installation of Plunger Lift Systems and the Development of Operational Practices that Minimize Methane Emissions*
  EPA should require the use of plunger lift systems at all gas wells unless the operator can adequately demonstrate that the well will not operate with sufficient shut-in pressure or production rate to be able to use such a system. EPA should also require all operators to develop an operational plan for managing the plunger lift systems so as to minimize venting.

- *Require the Installation of Downhole Separator Pumps, Where Applicable*
  EPA should require the installation of downhole separator pumps in applications where there is a lower lying water disposal aquifer.

- *Require Mud Degassing Vents Be Routed to a Vapor Recovery Unit*
  EPA should require that mud degassing vents be routed to a vapor recovery unit to reduce methane emissions.

F. Pipelines

Natural gas produced from gas fields is transported through pressurized pipelines to distribution systems. These pipelines require regular repair and maintenance as a result of corrosion (to both interior and exterior surfaces), leaks, materials failures, and damage caused by external factors. According to U.S. Greenhouse Gas Inventory data, pipeline leaks account for about 8 Bcf—or about 8 percent—of methane emissions from the transmission sector.[215]

1. Planned State Programs to Reduce Methane Emissions from Pipelines

Under CARB's Climate Change Scoping Plan, the state is considering a requirement for oil and gas operators to replace older equipment, such as flanges, valves and fittings, along pipelines.[216]

Mitigation Strategy," 2010, p. 1.

[215] Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 - 2007, USEPA, April, 2009, *see* http://www.epa.gov/gasstar/basic-information/index.html#sources.

[216] "Climate Change Scoping Plan Appendices, Volume 1: Supporting Documents and Measure Detail, a framework for change," California Air Resources Board, December 2008, pp. C-153 and C-154, http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf#page=184.

2. Available Proven Technologies for Pipelines

EPA's own Natural Gas STAR program provides evidence that there are many available, technically feasible and cost-effective technologies and operating practices that can greatly reduce methane emissions from pipelines. These options include both: (1) technology standards; and (2) improving operating practices to reduce emissions. EPA should, at a minimum, consider the following technologies and operating practices as cost-effective standards for reducing methane emissions from oil and natural gas systems.

Require the Use of Gas Main Flexible Liners and State-of-the-Art Pipeline Material and Protective Coatings

Cast iron and steel piping materials used in underground gas distribution systems have the highest leakage factors of all distribution piping materials.[217] According to EPA, plastic pipe has the lowest leakage rate.[218] EPA should require the use of the plastic pipe wherever feasible. Where the use of plastic pipe is not feasible EPA should require the use of flexible plastic insert liners. These types of plastic liners use the outer material for support but provide for the low leakage rates of plastic piping.

For pipelines that would be designed to have a protective coating, EPA should require the use of the best available coating technology to ensure maximum protection of piping materials. For example, PRITEC® is a protective coating made of a mixture of butyl adhesive and polyethylene that, according to EPA, is designed to "withstands exposure to weather and ultraviolet radiation for prolonged periods without degradation".[219] With increasing demand for oil and gas, pipelines are being installed in ever-more difficult environments. The pipeline coatings industry is reporting market developments and technology and materials innovations to meet the demands of today's applications.[220] Degradation of coatings due to exposure to the sun and to water (*e.g.*, in marine environments) can result in pipe corrosion and leaks. Requiring the use of the best available coating technology will help to minimize this potential source of methane emissions from pipelines. CARB already lists the replacement of cast iron and steel piping as a BMP for oil and gas sources.[221]

Require Several Operating and Maintenance Practices for Pipelines

In 2004, an estimated 12 Bcf of methane was vented to the atmosphere during routine pipeline maintenance and pipeline upsets. EPA should require that during routine maintenance, operators

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[217] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact SheetsNo. 403, "Insert Gas Main Flexible Liners", http://www.epa.gov/gasstar/documents/insertgasmainflexibleliners.pdf.
[218] *Id.*
[219] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact SheetsNo. 406, "Use of Improved Protective Coating at Pipeline Canal Crossings", http://www.epa.gov/gasstar/documents/useofimproved.pdf.
[220] *See*, e.g., the following October 20, 2010 News Report, "Pipeline Coatings Makers Face Historic Demands", http://www.paintsquare.com/news/article_news.cfm?id=4507.
[221] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.

be required to use pump-down techniques to reduce the gas line pressure in the pipeline before venting. Alternatively, operators could opt to use an ejector or use inert gases and pigs to purge pipelines.[222] All of these methods would reduce vented gas and can recover up to 90% of the gas in the line.[223] Operators can use in-line compressors or portable compressors to lower the gas line pressure (or ejectors) and should also be required to incorporate in-line compressor pump-downs into emergency procedures. In addition to reducing methane emissions, natural gas that would have been vented to the atmosphere can be recovered and sold. In the case of production pipelines, the gas stream might also contain valuable heavy hydrocarbons. Pump down techniques also reduce odor and noise pollution and virtually eliminate HAP emissions.[224]

Recent success of Natural Gas STAR Partner TransCanada's pump-down practices has resulted in the company's purchase of eight portable compressor units for use mainly on its high-pressure lines in Canada. Future possibilities include expanding its fleet of portable compressor units and implementing pump-down practices company-wide (36,500 miles of pipeline). TransCanada has reported increased revenue and decreased methane emissions from its pump-down practices.[225]

EPA should also consider requiring operating practices that reduce distribution system pressure. According to EPA, nearly all distribution sector methane losses are a result of unidentified fugitive leaks.[226] Systems that operate under higher than necessary pressure increase the amount of leakage that occurs. If operators are required to adjust system pressures at shorter intervals they can better match the current demand and reduce the amount of time the system operates under peak demand pressures. EPA should require operators to install automated control systems to regulate pressure. These automated systems will help ensure lower leak rates and less maintenance.

EPA should also require the use of hot taps for in-service pipeline connections. Hot tapping allows for a new pipeline connection while keeping the pipeline in service. Hot tapping avoids product loss, methane emissions, and disruption of service to customers.[227] According to EPA, "hot tapping has been found to be more cost effective than shutdown interconnects" and "recent design improvements have reduced the complications and uncertainty operators might have experienced in the past."[228]

EPA should require regular inspection of all flowlines in the production sector. The flowlines that transport natural gas from wells to transmission compressor stations or processing plant

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[222] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheets No. 404 and 405, "Install Ejector" and "Use Inert Gases and Pigs to Perform Pipeline Purges", http://www.epa.gov/gasstar/documents/installejector.pdf and http://www.epa.gov/gasstar/documents/useinertgases.pdf.
[223] Lessons Learned, Natural Gas STAR Partners, "Using Pipeline Pump-Down Techniques to Lower Gas Line Pressure Before Maintenance", October 2006, http://www.epa.gov/gasstar/documents/ll_pipeline.pdf.
[224] *Id.*
[225] EPA Natural Gas STAR Partner Update, Fall 2009, http://www.epa.gov/gasstar/newsroom/partnerupdatefall09.html.
[226] EPA Natural Gas STAR "Reducing Distribution System Pressure" Presentation, http://www.epa.gov/gasstar/documents/red_of_pressure_part1.ppt.
[227] Lessons Learned, Natural Gas STAR Partners, "Using Hot Taps for In Service Pipeline Connections", October 2006, http://www.epa.gov/gasstar/documents/ll_hottaps.pdf.
[228] *Id.*

booster stations are normally buried and, according to EPA, "can leak methane as a result of internal corrosion (particularly in wet, sour gas service), external corrosion, and abrasion from thermal cycling."[229] EPA estimates that methane leakage from flowlines is "one of the largest sources of emissions in the gas industry."[230] These underground leaks can be detected using ultrasound or digital radiography.

Require the Installation of Excess Flow Valves on All Gas Service Lines

EPA should require that excess flow valves be tested and proven at the time of installation and at periodic intervals not to exceed one year.[231] Gas line breaks can result in unexpected gas releases into the atmosphere. Methane emissions can be avoided by ensuring an automated shutoff of any ruptured gas service line through required installation of excess flow valves.

3. <u>Summary Recommendations for Pipelines</u>

EPA should implement the following for all new pipeline installations:

- *Require the Use of Gas Main Flexible Liners and State-of-the-Art Pipeline Material and Protective Coatings*
  EPA should require the use of the plastic pipe wherever feasible. Where the use of plastic pipe is not feasible EPA should require the use of flexible plastic insert liners. EPA should require the use of the best available coating technology to ensure maximum protection of piping materials.

- *Require Maintenance Practices for Pipelines*
  EPA should require that during routine maintenance, operators be required to use pump-down techniques to reduce the gas line pressure in the pipeline (or ejectors or use inert gases and pigs to purge pipelines) before venting. EPA should also require that in-line compressor pump-down techniques be incorporated into emergency procedures. EPA should require operators to install automated control systems to regulate pressure to ensure lower fugitive leak rates. EPA should also require the use of hot taps for in-service pipeline connections. EPA should require regular inspection of all flowlines in the production sector.

- *Require the Installation of Excess Flow Valves on All Gas Service Lines*
  EPA should require that excess flow valves be tested and proven at the time of installation and at periodic intervals not to exceed one year.

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[229] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 407, "Inspect Flowlines Annually", http://www.epa.gov/gasstar/documents/inspectflowlines.pdf.
[230] *Id.*
[231] *See* EPA Natural Gas STAR Program Partner Reported Opportunities (PRO), PRO Fact Sheet No. 610, "Install Excess Flow Valves", http://www.epa.gov/gasstar/documents/installexcessflowvalves.pdf.

G. Flaring

Flares are widely used in the oil and gas industry to combust unsalable gas or to dispose of gas released for safety measures or during testing. According to EPA,

> Flares in general can be categorized into two main types; continuous and intermittent. Continuous flares combust casing head gas, associated gas, well testing gas, and gas from equipment that generate a continuous waste gas stream (such as glycol dehydrators, storage tanks, and pneumatic devices). Intermittent flares combust releases that are not continuous in nature such as streams from equipment/ vessel/ site blowdowns and pressure relief valves.[232]

Although sending emissions to flares (rather than venting those emissions) eliminates methane, other air pollutants, including CO_2 are released into the atmosphere. The U.S. Energy Information Administration estimated CO_2 emissions from natural gas flaring to be 1,187.48 MMT in 2006.[233] In order to reduce methane emissions without increasing additional air pollution, alternatives to flaring should be required by EPA.

These emission estimates for flaring may grossly underestimate actual emissions from this source. According to EPA's recent rulemakings for the Mandatory Reporting of Greenhouse Gases program, several emissions sources are believed to be "significantly underestimated" in the U.S. GHG Inventory (EPA/GRI/Radian, 1996).[234,235] According to EPA, the emissions estimates for these under-reported sources "do not correctly reflect the operational practices of today" and, in fact, EPA believes "that emissions from some sources may be much higher than currently reported in the U.S. GHG Inventory."[236] EPA includes revised emission factors for all of the underestimated sources except the categories of crude oil and condensate storage tanks and flares for which "no new reliable data are available."[237]

EPA should avoid flaring as a control option for vented emissions, relying on vapor recovery technologies and operating practices that minimize vented emissions instead. A comprehensive plan to improve the environment through the reduction in methane emissions should not increase other air pollutant or greenhouse gas emissions. And, in fact, there are several existing international programs aimed at reducing the use of flaring as a control technique.

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[232] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, Appendix I.
[233] U.S. Energy Information Administration, *International Energy Annual 2006: World Carbon Dioxide Emissions from the Use of Fossil Fuels*, Table H.3co2, http://www.eia.doe.gov/iea/carbon.html.
[234] EPA/GRI (1996) *Methane Emissions from the Natural Gas Industry*. Prepared by Harrison, M., T. Shires, J. Wessels, and R. Cowgill, eds., Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC. EPA-600/R-96-080a.
[235] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 7.
[236] Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry Background Technical Support Document, U.S. Environmental Protection Agency Climate Change Division Washington DC, p. 23.
[237] *Id.* p. 7.

1. Existing International Programs to Reduce Flaring

The following international programs demonstrate that mandatory methane reduction programs can be implemented in parallel with programs aimed at eliminating or reducing flaring.

The World Bank's Global Gas Flaring Reduction (GGFR) Partnership is a public-private partnership started in 2002, with the goal of recovering natural gas that would normally be sent to flares or vented to the atmosphere. The GGFR partners include countries, organizations and gas companies, including the U.S. The GGFR developed a *Voluntary Standard for Global Gas Flaring and Venting Reduction* with the primary objectives of "eliminating routine sources of venting and eliminating or reducing the large sources of flaring. These goals can be achieved through investment in gas utilization projects that encourage the use of gas that would otherwise be flared or vented."[238]

Norway is said to be the world's leader when it comes to restrictions for flaring, and this country is a member of the GGFR. In 1996, the Petroleum Activities Act was passed, requiring that, "[b]urning of petroleum in excess of the quantities needed for normal operational safety shall not be allowed unless approved by the Ministry."[239] And according to the World Bank, routine flaring is not normally allowed in Norway under any economic conditions.[240]

In Alberta, Canada, the Energy Resources Conservation Board regulates flaring, incinerating and venting at oil and gas operations under, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting.* This measure addresses upstream operations as well as transmission facilities. These regulations and guidelines are broad and sweeping, and include detailed requirements for flaring, incinerating and venting at many emission points.[241] Directive 060 includes well test flaring, incinerating and venting duration limits; the testing time limit for gas wells is 72 hours in order to limit emissions from flaring and venting. In addition to the duration limits for testing, the rules require that in-line testing be used when it is economic and feasible.[242] Other sources of emissions, including gas batteries, dehydrators, compressor stations, gas plants and pipelines are required to limit flaring, incinerating and venting through such measures as volume limits.[243]

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[238] World Bank, GGFR Partnership, http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:20297378~menuPK:6296802~pagePK:64168427~piPK:64168435~theSitePK:578069,00.html.

[239] Norway Petroleum Activities Act No. 72, Section 4-4, 29 November 1996, last amended by Act 19 June 2009, No 104, http://www.npd.no/en/Regulations/Acts/Petroleum-activities-act/.

[240] World Bank, Comparison of Associated Gas Flaring Regulations: Alberta & Norway, http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/EXTOGMC/EXTGGFR/0,,contentMDK:21840526~menuPK:5221283~pagePK:64168445~piPK:64168309~theSitePK:578069,00.html.

[241] "*Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting,"* Energy Resources Conservation Board, Alberta, November 16, 2006.

[242] *Id*, p. 21-3.

[243] *Id. passim*.

2. Available Proven Technologies for Flaring

As described above, gas utilization projects can be implemented to eliminate flaring or venting. CARB lists the use of associated gas that would otherwise be vented or flared as a BMP. "Instead of venting or flaring, emissions can be reduced by using the associated gas for re-injection into the field for enhanced oil recovery, or for consumption within the facility."[244]

3. Summary Recommendations for Flaring

EPA should require producers to reduce emissions by instituting a gas utilization program, such as sending emissions to a vapor recovery unit, rather than flaring and venting. While flaring eliminates methane emissions, CO_2 and other air pollutant emissions are increased with the practice.

H. Directed Inspection and Maintenance

In addition to methane reduction technologies for the numerous emission sources at oil and gas operations, directed inspection and maintenance (DI&M) and other work practices can bring about large methane reductions. As previously described in this report under the "Compressors" section, DI&M is "a proven management practice for cost-effective reduction of methane emissions" that can significantly reduce fugitive methane emissions from the gas processing sector.[245] A DI&M program is not the same thing as EPA's regulatory leak detection and repair (LDAR) program for reducing VOC emissions.[246] A successful DI&M program includes a baseline survey, cost-effective repairs and subsequent targeted surveys based on findings from the initial baseline survey. In general, the cost of the baseline survey is reportedly recovered in gas savings during the first year.[247] The costs of subsequent surveys are minimized by focusing the components that were identified through the initial baseline study as having a high potential for leakage. A variety of screening and measurement devices (e.g., infrared gas imaging, optical remote leak detection, etc.) can be used to obtain accurate leak data and high volume gas samplers can be used to identify and quantify leaks.[248] According to EPA Natural Gas STAR partners, a DI&M program should "target the five categories of equipment components that contribute to the majority of methane losses: block valves, control valves, connectors, compressor seals, and open-ended lines."[249]

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[244] The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[245] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf.
[246] *See*, NSPS Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants.
[247] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf.
[248] *See, e.g.*, Directed Inspection and Maintenance (DI&M) at Gas Processing Plants, Innovative Technologies for the Oil & Gas Industry: Product Capture, Process Optimization, and Pollution Prevention, Targa Resources and the Gas Processors Association, July 27, 2006 Hobbs, NM, http://www.epa.gov/gasstar/documents/dim.pdf
[249] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, http://www.epa.gov/gasstar/documents/ll_dimgasproc.pdf.

The use of a DI&M program is also an effective means of reducing methane emissions at offshore oil and gas operations. In a paper on offshore platform methane reduction strategies, the authors analyzed offshore oil and gas methane emissions and control strategies to devise an emission reduction strategy for the most significant sources at the lowest cost. The implementation of a directed inspection and maintenance program to target fugitive emissions is one of the recommended strategies for reducing methane emissions in offshore applications.[250] In addition, both the BLM and CARB list the use of directed inspection and maintenance programs as a BMP for oil and gas sources.[251]

1. Existing International Programs to Reduce Methane Emissions Using Directed Inspection and Maintenance

As described above under the "Compressors" section of this report, the Ukrainian natural gas transmission company, Cherkasytransgas, implemented a directed inspection and maintenance program at its compressor stations in 2002 with huge success in reducing methane emissions. The last round of repairs, in 2008-2009, reduced annual methane emissions by 3.5 million cubic meters when the company upgraded the sealant on 174 valves at transmission stations, distribution stations and linear pipes.[252]

2. Available Proven Technologies/Methods for Directed Inspection and Maintenance

In addition to the DI&M program described above for compressor stations, there are several other promising technologies available to further reduce methane emissions.

Directed Inspection and Maintenance at Gate Stations and Surface Facilities and Gas Processing Plants and Booster Stations

Gate stations are the gas transfer point from transmission pipeline to the distribution system, where the gas is depressurized. The surface facilities contain heaters and pressure regulators. "Gate stations and surface facilities contain equipment components such as pipes, valves, flanges, fittings, open-ended lines, meters, and pneumatic controllers to monitor and control gas flow."[253] Methane emissions from leaking meters and regulating equipment at gate stations and surface facilities account for around 27 MMcf. Using a DI&M program, operators use a baseline survey of the gate stations and surface facilities to direct further inspection and maintenance

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[250] Bylin, Carey et al. for Society of Petroleum Engineers, "Designing the Ideal Offshore Platform Methane Mitigation Strategy," 2010, p. 1.
[251] U.S. Department of Interior, Bureau of Land Management, "Air Resource BMPs," 8/24/09, www.blm.gov/gov and The California Air Resources Board's Clearinghouse of non-CO_2 Greenhouse Gas Emission Control Technologies, http://www.arb.ca.gov/cc/non-co2-clearinghouse/non-co2-clearinghouse.htm.
[252] Methane to Markets, Oil & Gas Methane Reduction Project Opportunity, "Directed Inspection and Maintenance and Valve Sealant Updgrades," Cherkasytransgas, Cherkassy, Ukraine, http://www.methanetomarkets.org/projects/projectDetail.aspx?ID=1152.
[253] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gate Stations and Surface Facilities," October 2003, p. 2, http://www.epa.gov/gasstar/documents/ll_dimgatestat.pdf.

measures. Likewise, a DI&M program can also be used at gas processing plants and booster stations to reduce methane emissions, which emit an estimated 36 Bcf annually.[254]

The same leak detection practices can be utilized at gate stations and surface facilities as well as gas processing plants and booster stations. Several options for leak screening techniques exist, including soap bubble screening, electronic screening using hand-held gas detectors equipped with catalytic oxidation and thermal conductivity sensors, organic vapor analyzers and toxic vapor analyzers which are also portable devices with hydrocarbon sensors, and portable acoustic leak detection devices. Leak measurement techniques are another important component to a DI&M program. Options for leak measuring include: organic vapor analyzers and toxic vapor analyzers used to estimate mass leak rates, "bagging techniques" where the leak or leaking component is covered with a bag or tent to collect and measure the gas, high volume samplers collect and accurately quantify leak emission rates, and rotameters and other high volume meters are used to measure large leaks.[255]

Directed Inspection and Maintenance Using Infrared Laser Detection

There are several leak detection options under this category. Live leak imaging cameras provide real time and video recordings of gas leaks using infrared technology to detect otherwise invisible gas. Aerial leak surveys are performed by helicopter to detect large leaks at remote facilities. There are also infrared laser techniques available to use laser beam to scan methane leaks.[256] Dynegy Midstream Service, LLP, has had great success in reducing methane leaks using a DI&M program that involves aerial optical surveying and handheld optical surveying. Using the aerial screening method, Dynegy was able to identify and repair leaks in its pipelines, reducing its annual methane emissions. Dynegy also used handheld optical devices to further reduce methane emissions.[257]

Work Practices

In addition to a DI&M program, Natural Gas STAR partners have achieved methane reductions through work practice techniques. These work practices include eliminating unnecessary equipment and/or systems, optimizing processes, decreasing the time between fugitive emissions "walking" surveys and requiring improvements in the quality of gas received from producers.[258]

3. Summary Recommendations for Directed Inspection and Maintenance

EPA should require that operators implement DI&M programs and good work practices in all possible sectors in order to detect and reduce methane emissions.

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[254] Lessons Learned, Natural Gas STAR Partners, "Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations", October 2003, p. 1.
[255] *Id.,* pp. 3-7.
[256] US EPA's Natural Gas STAR: Directed Inspection and Maintenance (DI&M) Using Infrared Laser Detection, http://www.epa.gov/gasstar/documents/leak_detect.pdf.
[257] Natural Gas STAR Partner Update, Fall 2005, p. 2, http://www.epa.gov/gasstar/documents/ngstar_fall2005.pdf.
[258] http://www.epa.gov/gasstar/tools/recommended.html#other.

III. CONCLUSION

Oil and gas extraction and production emit significantly large quantities of GHGs and other air pollutants, and U.S. oil and gas production is expected to grow rapidly. The oil and gas industry's significant emissions of GHGs and other air pollutants and forecasted growth warrant significant action on the part of EPA. Oil and gas production has exploded in places like the Rocky Mountain West, contributing to rising greenhouse gas emissions as well as unprecedented air pollution levels.

Given that:

(1) methane emissions from oil and gas development in the U.S. constitute a significant, often underestimated and growing portion of the overall greenhouse gas mix; and

(2) methane is a potent greenhouse gas with a relatively short atmospheric lifetime, making it a prime candidate for impacting climate change in the short-term; and

(3) methane emissions contribute to ozone pollution; and

(4) there are already many proven technologies and practices available to significantly reduce methane emissions from oil and gas systems; and

(5) these technologies also offer opportunities for significant cost-savings in the form of recovered methane gas;

the need for meaningful performance and operating standards to reduce methane emissions from the oil and gas source category is vital to ensure that increasing energy production does not occur at the cost of our nation's air quality and public health.

EPA has failed to date to implement and maintain comprehensive standards for the oil and gas sector, despite the fact that our understanding of the adverse impacts of methane emissions on public health and welfare has improved—in particular with regard to methane's significant contribution to climate change and ozone pollution. We urge EPA to issue comprehensive regulations for the oil and gas sector, including standards and practices targeted at achieving meaningful methane emissions reductions. New source standards and operating practices should be based on the available methane reduction and reuse technologies that reflect best demonstrated technologies and practices.

EPA must also adopt comprehensive monitoring, reporting and recordkeeping requirements to support new and revised NSPS for the oil and gas sector. These compliance demonstration techniques should be aligned with the recently finalized reporting requirements for the oil and gas industries in Subpart W of 40 CFR Part 98.[259] Under EPA's mandatory reporting requirements, facilities are required to quantify GHG emissions, including methane emissions, according to a range of methods that include the direct measurement of emissions, engineering estimation methods (*e.g.*, simulation models, engineering calculations, original equipment

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[259] Administrator Jackson signed the rule on November 8, 2010 (Federal Register citation pending).

manufacturer emission factors, default emission factors, etc.), leak detection and leaker emission factors as well as equipment count and population emission factors. We urge EPA to develop mechanisms to move the newly-established reporting system steadily towards the most accurate and precise reporting methods possible which will mean moving towards the use of more direct measurement methods and will also mean systematically and periodically auditing and reviewing the reporting requirements to ensure continuous improvement in the reported data. EPA should commit to a rigorous periodic statistical sampling and audit program in order to ensure continuous improvement in the data collected under the MRR and in the compliance demonstration techniques used in support of NSPS. EPA should establish as part of this rulemaking comprehensive compliance demonstration methods and a plan for periodically updating these methods as improvements in the techniques for monitoring methane emissions from oil and gas sources occur. Rigorous monitoring techniques that are based on the latest measurement methods will be a key component of NSPS for the oil and gas sector.

Megan M. Williams

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SKILLS

Over 10 years of experience working on air quality issues

Technical and Policy areas of expertise

- Analyzing and characterizing air emissions from a variety of air pollution sources
- Determining air emissions reduction potentials from control technology scenarios
- Reviewing public lands management actions taken under the National Environmental Policy Act (e.g., Environmental Impact Statements, Environmental Assessments, Resource Management Plans, Travel Management Plans, etc.)
- Reviewing new, existing and modified state air quality regulations to determine if they meet federal Clean Air Act requirements
- Reviewing proposed federal and state air quality rules and policy to determine if they are as rigorous and stringent as possible
- Thorough understanding of the requirements of the nonattainment new source review and prevention of significant deterioration construction permit programs and Title V operating permit program

Computer skills

- Highly proficient in MS Windows and Macintosh
- Experienced with numerous standard software packages
- Experienced writing programs to perform data analysis (*e.g.*, Excel macros, etc.)

Communication skills

- Experienced and thorough in writing both technical and policy documents
- Presented half-day technical seminars on Indoor Air Quality (to teachers, maintenance staff, etc.)
- Active in EPA's Environmental Education Council (1998-2000)

Completed numerous technical and policy courses offered by the EPA Education and Outreach Program

PROFESSIONAL EXPERIENCE

VARIOUS ENVIRONMENTAL AND GOVERNMENT ORGANIZATIONS Boulder, CO
July 2003–present

Air Quality Consultant

- Provide a variety of technical and policy analyses related to national, regional and local air quality and energy issues. Includes technical and policy research, the production of written documents and reports, quantitative determinations and qualitative assessments.

U.S. ENVIRONMENTAL PROTECTION AGENCY — Denver, CO
January 1998–November 2002

Environmental Engineer, May 2000–November 2002
Air Quality Planning Group

- Region 8 lead for nonattainment new source review and prevention of significant deterioration policy development and planning analyses (2001–2002)
- Reviewed state rules and rule changes related to new source review permitting to determine if they met federal Clean Air Act requirements
- Prepared official documents to approve or disapprove state implementation plan revisions
- Reviewed PM_{10} redesignation requests and prepared official documents for redesignating PM_{10} nonattainment areas to attainment
- Primary contact for Wyoming air issues (2001–2002)
- Compiled EPA-approved implementation plan for Wyoming
- Co-led a national working group to re-examine EPA's existing policy on redefining "baseline areas" under the Clean Air Act. Planned and hosted national workgroup meeting in Denver to develop criteria for approving baseline area redesignations. Co-authored a Technical Memo to EPA's Office of Air Quality Planning & Standard's Director proposing use of the new criteria
- Received Superior Accomplishment Recognition for technical and policy work on an air quality dispersion modeling analysis of Prevention of Significant Deterioration (PSD) increment consumption in North Dakota and eastern Montana (report available upon request).

Regional Indoor Air Quality Program Manager, January 1998–May 2000

- Managed EPA Region 8's voluntary Indoor Air Quality Program
- Provided technical assistance and outreach to schools, state/local officials and the general public
- Initiated and managed research projects to assess indoor air quality interventions
- Developed and maintained regional IAQ website
- Received Superior Accomplishment Recognition for working with schools to voluntarily implement EPA's Indoor Air Quality Tools for Schools program
- Received regional award for Excellence in Environmental Education

WISCONSIN DEPARTMENT OF NATURAL RESOURCES — Madison, WI

Air Management Engineer, January 1997–December 1997

- Wrote Title V Operating Permits for sources in northwest Wisconsin (*e.g.*, power plants, paper mills, breweries, and military operations)

Air Management Intern, August 1995–December 1996
(part-time position in conjunction with the Air Resources Management graduate program at UW - Madison)

- Wrote Title V Operating Permits for sources in northwest Wisconsin
- Developed statewide general Title V Operating Permits for small heating units and ethylene oxide sterilizers

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EDUCATION

UNIVERSITY OF WISCONSIN – MADISON
Institute for Environmental Studies
Master of Science, Air Resources Management, December 1996

UNIVERSITY OF COLORADO – BOULDER
College of Engineering and Applied Sciences
Bachelor of Science, Applied Mathematics (emphasis Mechanical Engineering), May 1995

CINDY S. COPELAND

1071 Tantra Park Circle · Boulder, CO 80305 · 303-520-8248 · cindycopeland5@gmail.com

FOCUS AREA

Outstanding background in environmental policy with a focus on air quality and climate change. Extensive experience with air pollution reduction control strategies and scenarios.

SKILLS

Over 10 years of experience working on air quality issues

Technical and Policy areas of expertise
- Analyzing and characterizing air emissions from a variety of air pollution sources
- Determining air emissions reduction potentials from control technology scenarios
- Reviewing new, existing and modified state air quality regulations to determine if they meet federal Clean Air Act requirements
- Reviewing proposed federal and state air quality rules and policy to determine if they are as rigorous and stringent as possible
- Thorough experience with the requirements of particulate matter control through state implementation plan requirements under the Clean Air Act

Communication skills
- Numerous presentations made to state and tribal air quality officials
- Extensive experience in negotiations over highly technical and politicized issues
- Experienced and thorough in writing both technical and policy documents
- Testified at hearings for federal and state rulemakings
- Experience with press statements and presentations
- Preparing briefings for high level management

EXPERIENCE

Environmental Consultant. (January 2006-present)
- Extensive policy and technical analyses of federal and state actions concerning air quality and climate
- Represent environmental groups at stakeholder meetings

Program Associate. Environmental Defense, Boulder, Colorado (March 2004-September 2005)
- Assisted with a variety of policy and technical air quality reviews
- Coordinated and contributed to official organization reports on air quality and climate
- Represented organization in state stakeholder and rulemaking processes
- Authored extensive regulatory and technical letters commenting on EPA and state actions
- Testified at state and federal regulatory hearings on proposed rule changes

Teaching Assistant. University of Colorado, Boulder, Colorado (Spring Semester 2003)
- Instructed two undergraduate sections of a weather lab
- Graded student work products

Environmental Protection Specialist. U.S. Environmental Protection Agency, Region 8, Denver, Colorado
(January 1998-August 2002)
- Acted as the Environmental Protection Agency Region 8 Particulate Matter Program Manager
- Participated in development of air pollution control regulations for Colorado, Montana, Utah, Wyoming, North Dakota, South Dakota and 27 local Tribal governments
- Represented all EPA Regions as the Regional lead on particulates and collaborated with the EPA's headquarters office on policy development and implementation
- Received the EPA Bronze award for being the lead program person on the redesignation of the Denver PM_{10} nonattainment area to attainment/maintenance.
- Presented information updates and issues to State and Tribal environmental divisions, including State Air Directors and State Air Quality Boards
- Presented public outreach on outdoor air, indoor air, and asthma
- Reviewed, evaluated and approved state air quality plan revisions
- Responded to state, local and private inquiries to requirements and implementation of the Clean Air Act
- Coordinated and conducted internal and external meetings to evaluate, resolve, and implement solutions to issues with technical, legal, and managerial personnel
- Served on the Region 8 agricultural task team

EDUCATION

Master of Science. University of Colorado Environmental Studies Program (2004)
Thesis: *Facing Climate Change in New Mexico*

Bachelor of Arts. Willamette University, Salem, Oregon (1997)
Major: Politics
Minor: Environmental Science
Senior Thesis: *Global Climate Change: The International and United States Responses*