WESTERN ENERGY
ALLIANCE

July 6, 2015

Nicole Owens
Director, Regulatory Management
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Dear Ms. Owens:

Western Energy Alliance, in its role as a Small Entity Representative (SER), respectfully submits the following comments to the Small Business Advocacy Review (SBAR) Panel for the EPA rulemaking *Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector*. EPA is soliciting SER input for its SBAR Panel to offer the perspective of small entities that will be required to comply with EPA's forthcoming rulemaking.

Western Energy Alliance represents over 450 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas in the West. The Alliance represents independents, the majority of which are small businesses with an average of fifteen employees.

EPA Has Not Provided Adequate Time for Review

As we commented during the pre-panel process, we believe that EPA has not provided adequate information for SERs to thoroughly review the cost and impacts on small entities, which limits the scope and specificity of our input. On June 18th, EPA provided SERs with unsupported cost estimates for a wide range of emission control strategies that lacked any background information on the assumptions, sources, and decisions behind those cost estimates.

Analysis of the cost information is impossible due to the many assumptions made by EPA and lack of supporting information. Therefore, we request clarification from EPA on the supporting information behind its cost assumptions. As an example, the representative gas analysis information used in the oil well completion calculations assumes a 46.732% methane concentration by volume for associated gas. EPA references a memorandum in support of this estimate, yet the memorandum itself does not provide any data for the basis of this assumption.[1] There are numerous other points that require clarification before we can determine the accuracy of EPA estimates, therefore we request an

[1] *Memorandum to Bruce Moore EPA/OAQPS/SPPD: Composition of Natural Gas for use in the Oil and Natural gas Sector Rulemaking*, Docket ID EPA-HQ-OAR-2010-0505-0084, Heather Brown, , July 2011.

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additional meeting with EPA once participants have been given adequate time to review the material presented on June 18th.

On June 23rd, EPA submitted its draft rules to the Office of Management and Budget (OMB) despite not having completed the SBAR panel process. It is our understanding that the SBAR panel is designed to inform rulemaking and provide information on how EPA can avoid disadvantaging small businesses. However, by releasing the rule for OMB review prior to receiving SER input, it does not appear that EPA intends to take the SBAR panel's recommendations into account. This action undermines the SBAR process and demonstrates a lack of concern over the rule's impact on small businesses.

Leak Detection and Repair Program Concerns

In our initial comments, we expressed significant concern regarding the inclusion of a Leak Detection and Repair (LDAR) program in the forthcoming regulations. In particular, we provided information on why Colorado's Regulation 7 LDAR program is not suitable as a national model. In response to EPA's request for additional information on the Colorado model, we draw EPA's attention to an economic analysis conducted by Louis Berger Group to review the Colorado Department of Public Health and Environment (CDPHE) analysis.[2]

Louis Berger evaluated the impact of Colorado's LDAR program on marginal wells and determined that the stringent LDAR program implemented by CDPHE has high compliance costs that would make many marginal wells un-economic. Louis Berger's analysis showed that 55% of active wells in Colorado produce less than two barrels of oil per day (bopd). In 2013 when the analysis was conducted, the economic limit at which production revenues no longer cover lease operating expenses was 0.43 bopd. Under Colorado's LDAR program, that number is estimated to be more than double, at 1.05 bopd. Over the life of currently producing wells, this additional burden will ultimately result in 128 million barrels of oil being left in place, $11.6 billion in lost revenue to producers, $2.3 billion in lost royalties, and $579 million in lost severance taxes in Colorado. Given the current oil price environment, the break-even threshold is likely even higher than 1.05 bopd, which will result in even greater production losses and revenue losses. The burden of compliance on marginal wells will be especially detrimental for small producers who may not have a large asset base to offset compliance costs.

Colorado's LDAR program poses numerous compliance issues in addition to the loss of marginal wells. It imposes overly strict inspection schedules that offer minimal environmental benefit. In the overwhelming majority of instances, after initial leaks are found and fixed, the rate of leak frequencies drops dramatically. The benefits of subsequent rounds of inspection diminish greatly over time, which further reduces the cost-effectiveness of the program. However, CDPHE failed to account for this diminishing

[2] *Testimony to Colorado Air Quality Commission of Regulation 7 Economic Impact Analysis*, Lisa McDonald, February 19-23, 2014, p. 39-55.

return in its cost analysis and as a result, created a flawed rule. This problem is compounded in areas where locations are remote and difficult to access. Long travel times create additional expense, produce vehicle emissions that negate any possible air quality benefits and rarely detect any leaks in later years. Additional costs that must be accounted for include the:

- Time and resources to fulfill LDAR reporting requirements, either in-house or third-party
- Cost for parts necessary to repair leaks
- Cost of time to repair leaks
- Cost of time to re-camera the leaking equipment after repairs to ensure no leaking
- Time to complete paper work to document completed and effective repairs
- Lost production from equipment downtime during leak repairs
- Cost of infrared cameras and maintenance of camera, factoring in the length of warranty
- Operator or third-party vehicle maintenance to perform LDAR
- Cost to identify accurate component counts used for LDAR, as well as other functions, such as permitting.

In many cases, the additional resources required for an extensive inspection program will disproportionately impact small businesses that do not have large dedicated compliance groups. In the June 18th presentation, EPA discussed “reduced frequencies” of inspections. We strongly encourage EPA to clarify what this means in a follow-up presentation and allow small entities to take that information into consideration. In the original New Source Performance Standards Subpart OOOO, EPA avoided overly-prescriptive inspection requirements and instead allowed monthly or quarterly audio, visual, and olfactory (AVO) inspections, which may be an approach to consider for oil well completions. AVO inspections are as effective in finding the leaks as the infrared camera inspections but are more cost effective.

EPA should also consider the timing of repairs following leak detection. In some instances, it may be counterproductive to repair a leak right away. For safety concerns, some repairs may require well blowdowns that result in far greater emission releases than the initial leak itself. An LDAR program must provide regulatory flexibility to allow for common-sense operational considerations.

Pneumatic Controls, Pneumatic Pumps and Compressors

In slides presented on June 18th, EPA estimated the proposed controls would cost $200-$8,000 depending on the process chosen. However, these cost estimates appear to only consider the cost of the equipment itself. EPA does not acknowledge in its presentation or its white papers the cost of the time consumed and verification of repairs, which disproportionately burdens small entities with limited resources and staff. Controls for gas pneumatics also would likely not be cost-effective based on the volumes of emissions recovered. EPA also proposes instrument air as a substitute for gas pneumatics; however this is not practical due to the remote location and lack of power at many upstream locations. EPA needs to revise its compliance options and cost estimates to reflect the full implementation cost.

The exemption for well-site compressors should remain unchanged. The existing rules for non-wellsite compressors are aligned with prevailing compressor maintenance practices, but adding small compressors would dramatically expand the scope of this rule. A one-size-fits-all compressor rule would likely pull in far more than the 50-100 sources anticipated by EPA. If EPA expands the rules to cover small wellsite compressors, it will need to dramatically revise the estimates and consider those additional impacts.

Oil Well Completions

In the June 18th presentation, EPA asked for additional information regarding exemptions from oil well completions based on production thresholds and gas-to-oil ratios (GOR). We do not recommend using production-based thresholds or GOR for exemptions from oil well completion requirements because this information is not available at the pre-fracturing stage. It would be more effective to base exemptions on field-wide production in barrels per field or company size in revenue or number of employees, rather than GOR or well production thresholds

We also question EPA's analysis of the oil well completion emission benefits. In its analysis, EPA states that methane is 46.732% of the volume of gas produced during a well completion. Based on initial surveys of operators, this number is highly inaccurate. Given the limited time provided by EPA, we have not been able to conduct extensive data gathering. However, our preliminary analysis suggests a more representative range would be 40-80% methane with many basins producing gas that is over 60% methane. It is important to note that the remaining gas volume is not entirely volatile organic compounds (VOCs). Gases like ethane, carbon dioxide, and nitrogen can make up significant volumes of produced gas. In many cases, VOC emissions are likely 10-30% of total volume. Again, these data are only preliminary due to the lack of time EPA has given us to review and gather information, but it would appear that EPA's oil well completion numbers need substantial revision.

Serving to further complicate matters, EPA presents information in an annualized format with the cost savings already included, which makes it difficult to pull apart the assumptions. In order to provide EPA with more accurate oil well completion information, we surveyed members regarding their oil well completion practices. Given the extremely limited timeframe and the large amount of data needed, this table must be considered preliminary and requires further information before it can be treated as complete.

Oil Well Completion Data

	DJ Basin	Williston Basin	Powder River Basin
Days to complete (flowback)	2-7	2-7	21-28
Additional green completion cost per day ($/day)	$2,000-$7,200	$3,500-$10,800	$8,400
Average volume of gas produced during completion (MCF/day)	1,500-3,000 MCF	300-2,500 MCF	100-1,500 MCF
Average % gas currently flared during completion	50-80%	50-80%	90-100%
Average % gas currently sold during completion	20-50%	20-50%	0-10%
Average % gas currently vented during completion*	< 1%	< 1%	< 1%
Methane gas composition %	40-80%	50-70%	70-80%
VOC gas composition %**	10-30%	10-30%	10-20%

The data show that gas is largely controlled through flaring or capture and sales. For safety reasons operators vent as little gas as possible. Regulations seeking to minimize venting for oil well completions are redundant under current industry practices. Also of note is the high variability of well flowback times and costs per green completion. A one-size-fits-all cost analysis will almost certainly fail to capture the highly variable nature of well completion operations. Small operators also tend to be on the high end of completion costs. They typically conduct completions less frequently and lack the purchasing power to get the discounted prices service companies offer to larger operators, therefore a one-size-fits-all cost estimate would likely not adequately represent the cost burden faced by small operators.

The high variability of well completion practices underscores that it is not possible to conduct the comprehensive analysis that is needed for these complex operations within the time EPA has provided. EPA should provide SERs with more time to gather meaningful input on how to classify oil well completion thresholds and determine the cost of reduced emission completions. We strongly recommend that EPA hold another review session for SERs after they have been given adequate time to gather this necessary information as EPA clearly does not have enough information at this point to make an informed decision on how to define oil well completion exemptions. Oil well completion controls, if applied too broadly, could greatly disadvantage small producers that may not be able to absorb the incremental costs of those controls.

Upstream Methane Control Strategies are Not Cost-Effective

We raised concerns over targeting upstream methane emission sources in our pre-panel comments, but these concerns are still not adequately addressed in the information presented by EPA to date. A methane control strategy for upstream oil and natural gas operations threatens to skew the economic hardship towards small upstream operators without offering cost-effective reductions. Instead, a control strategy aimed at achieving the greatest emission reductions at the lowest incremental cost must focus on the natural gas processing, transmission and storage sectors. EPA's own series of white papers on emission sources notes that upstream methane emissions from compressors are 86,000 MT at gas production sites versus 1,985,000 MT from gas processing, transmission and storage sites. These downstream operations emit at 23 times the rate of upstream sites and clearly present the opportunity to achieve greater emission reductions. Upstream compressor controls would be extremely burdensome for many small operators given the significant capital expense associated with compressors and would clearly miss the bulk of emission reduction opportunities, which are found downstream.

According to a study by the University of Texas, Austin, methane emitted from all upstream source categories at natural gas production sites represents just 0.42% of gross natural gas production volumes.[3] Chasing a small source of emissions is not cost-effective, and will be particularly burdensome on small producers. In addition, it is counterproductive to the President's overall climate change goals, as greater use of natural gas, particularly for electricity generation, is one of the main reasons for decreases in overall U.S. greenhouse gas emissions. Putting in place expensive requirements to capture a small source of emissions at the upstream sector will result in less natural gas production, higher prices for consumers, and hence, less climate change benefit.

Thank you for considering these comments and recommendations. We appreciate the opportunity to participate in the process. However, to provide meaningful input we require additional time, data and clarification from EPA regarding the cost estimate assumptions in its white papers and presentations. EPA has not satisfactorily provided the information needed to fully address the impacts of forthcoming regulations on small businesses. We look forward to additional details so that we can help EPA understand the full cost implications.

Sincerely,

Kathleen M. Sgamma
Vice President of Government & Public Affairs

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[3] "Measurements of methane emissions at natural gas production sites in the United States," *Proceedings of the National Academy of Sciences of the United States of America Vol. 110 No. 4*, Allen et. al., August 19, 2013.