New Methane Regulations Proposed for the Oil and Gas Sector: What You Need to Know

V&E Shale Insights – Tracking Fracking E-communication

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On August 18, 2015, EPA proposed a slate of rulemakings under the Clean Air Act (the "Act") directed at the oil and gas industry. These rulemakings would, if promulgated along the lines proposed, achieve the following:

- establish New Source Performance Standards ("NSPS") for methane and volatile organic compound ("VOC") emissions from the oil and gas sector;
- redefine the fundamental term "source" in a way that may add burdensome requirements, extend the time and permitting risks associated with permitting sources, and potentially require additional controls; and
- require states to mandate additional pollution controls in states that are non-attainment for ozone, through Controls Technique Guidelines ("CTGs") that states will be forced to implement.

These rules will have widespread application to the oil and gas industry and could have impacts on production, processing, transmission, and storage vessels. Businesses and individuals concerned about this proposed rule or interested in participating in EPA's decision making process have only 60 days after the proposed rule is published in the federal register to submit comments to the agency.

It is important to note that these changes — once adopted — will apply to any covered source built or modified after the *Federal Register* proposal date, regardless of when the rule is made final. Accordingly, owners and operators need to begin now to design and build their operations to comply with the performance requirements imposed by these proposed rules.

I. NSPS Proposal

Background

EPA explains that it released this proposal because methane has been determined by the agency to be a greenhouse gas ("GHG"), and the oil and natural gas category is currently one of the U.S.'s largest emitters of methane. EPA already has established standards for emissions of VOC and SO2 for several select operations in the oil and gas sector through regulations codified as "Subpart OOOO." The Subpart OOOO regulations already resulted in a large reduction in methane emissions, even though they were not expressly mentioned, causing some to question whether this separate methane rule was necessary.

Still, EPA proposes to amend those regulations to include standards for reducing methane, as well as VOC emissions, across the oil and natural gas source category, which EPA defines to include production, processing, transmission and storage. This proposal would expand the existing VOC standards to cover additional equipment, and establishes new methane standards for equipment regulated under the 2012 rulemaking and the remainder covered by this regulation as well. The proposal would extend the current VOC best system of emission reduction ("BSER") standards found in Subpart OOOO for VOC to methane emissions for the expanded list of equipment identified in the new rule.

This chart provides a comparison between the previous Subpart OOOO and the proposed changes:

Requirement	Subpart OOOO	Proposed Rule
Regulates VOCs	Yes	Yes
Regulates Methane	No, but controls are identical to those now required for methane	Yes
Hydraulically fractured oil well completions	No	Yes
Hydraulically fractured gas well completions	Yes	Yes

Requirement	Subpart OOOO	Proposed Rule
Fugitive emissions at well sites and compressor stations	No	Yes
Equipment leaks at natural gas plants	Yes	Yes
Pneumatic Pumps and Controllers	No	Yes
Control requirements	BSER	BSER (same controls)

How will this impact existing state regulation?

EPA acknowledges that states may already have more stringent requirements and suggests that affected sources already in compliance with those state requirements will also be in compliance with the proposed NSPS.

What are the costs of compliance?

Section 111 of the Act requires that EPA consider a number of factors, including cost, in determining the BSER standards. EPA estimates the total industry-wide capital cost of complying with the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. In addition, EPA estimates the total annualized engineering costs of the proposed NSPS to be $180 to $200 million in 2020 and $370 to $500 million in 2025 when using a 7 percent discount rate.

Despite these high industry-wide costs, EPA concludes that the proposed rule has a net economic benefit. To reach this conclusion, EPA considered the revenues that it expects operators will generate from selling the methane that would have otherwise been emitted into the atmosphere. EPA has valued the methane at about $4.00 per Mcf. EPA estimates that 8 billion cubic feet in 2020 and 16 to 19 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS. Especially given the current state of the market, these estimates are speculative.

EPA's conclusion also is based partially on its use of a model called the Social Cost of Methane. EPA used this model to place a present-dollar value on projected future benefits to the climate from reducing methane emissions. Based on the model and the three percent discount rate that EPA used in the cost-benefit analysis, EPA determined that every ton of methane emissions that this rule prevents is worth $1,100 in 2015.

EPA projects that the proposed rule would prevent 170,000 to 180,000 tons of new methane emissions, 120,000 tons of new VOC emissions, and 310 to 400 tons of new hazardous air pollutants ("HAP") emissions in 2020. The proposal estimates that these emission reductions would increase to 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP in 2025. As a result, EPA estimates the methane-related monetized climate benefits of the proposal to be $200 to $210 million in 2020 and $460 to $550 million in 2025. According to EPA's calculations, in 2010 the total GHG emissions from U.S. oil and natural gas production, and natural gas processing and transmission accounted for 0.3 percent of the global GHG emissions.

II. Upstream Impacts

The proposal expands the VOC and methane standards to apply to hydraulically fractured oil well completions, and fugitive emissions from oil well completions—two sources of emissions not currently regulated under Subpart OOOO. Hydraulically fractured natural gas wells, which already are subject to the VOC regulations under Subpart OOOO, also would be subject to the new methane regulations, but these sources should be able to meet the methane emission requirements without additional upgrades or controls. The proposed regulations would cover pneumatic controllers and pumps, as well as storage tanks at oil and natural gas well sites. In addition, EPA is requesting comments on technologies and techniques to reduce methane and VOC emissions during liquids unloading operations. These sources are not currently covered by Subpart OOOO and would need to come into compliance.

Well completions

The proposed well completion operational standards are the same as the current Subpart OOOO standards for natural gas wells, but would expand the rule to also cover oil wells with a gas-to-oil ratio of more than 300 standard cubic feet (scf).

For subcategory 1 wells (non-wildcat, non-delineation wells)[1] the proposal would require owners and/or operators to use reduced emission completions (also referred to as "RECs" or "green completions") to reduce methane and VOC emissions in combination with a completion combustion device, such as flares or controlled combustion control devices to prevent emissions when the gas is not salable. RECs use a separator to remove gas and liquid hydrocarbons from the flowback so that the gas and hydrocarbons can then be treated and used or sold. The proposal does not require RECs where the use of a separator is technically infeasible. For subcategory 2 wells (wildcat and delineation wells), the proposal would only require owners and/or operators to use a completion combustion device, and not RECs. Well completions done as part of a refracturing operation are not subject to this portion of the proposal as long as they meet the current Subpart OOOO requirements, but may still be subject to fugitive emissions requirements.

The proposal would require gas controls during and after the second flowback stage (the "separation flowback stage") to begin when the separator can function. During this stage, all salable quality gas must either be collected, re-injected, or used either for on-site fuel or for another useful purpose. If it is technically infeasible to route the gas in this way, or if the gas is not of salable quality, the operator must combust the gas unless combustion creates certain fire, safety, or environmental hazards, and the proposal does not allow direct venting of gas during the separation flowback stage. During the initial and second flowback stages, all flowback liquids must be routed to a well completion vessel, a storage vessel or a collection system.

For subcategory 2 wells, the proposal would require routing of the flowback into well completion vessels and commencing operation of a separator unless it is technically infeasible for the separator to function. Once the separator can function, recovered gas must be captured and directed to a completion combustion device unless combustion creates a fire, safety, or environmental hazard. As with the current Subpart OOOO standards, low pressure wells would also be subject to these subcategory 2 requirements.

In addition to these specific requirements, the proposed rule places a general duty on operators "to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery." This vague language could create potential compliance risks for operators.

Fugitive Emissions

What equipment and wells would be regulated?

The proposed rule would regulate the collective fugitive emissions from the "well site" — defined as "one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by,

[1] Wildcat wells, also referred to as exploratory wells, are wells drilled outside known fields or are the first wells drilled in an oil or gas field where no other oil and gas production exists. Delineation wells are wells drilled to determine the boundary of a field or producing reservoir. Well completions done as part of a refracturing operation are not subject to this portion of the proposal as long as they meet the current Subpart OOOO requirements, but may still be subject to fugitive emissions requirements.

production facilities directly associated with any oil well, gas well, or injection well and its associated well pad" — including all ancillary equipment in the immediate vicinity of the well that is necessary for or used in production, such as separators, storage vessels, heaters, dehydrators, or other equipment at the site. The requirements would apply to all new wells site, or sites modified after effective date of the final rule.

The proposed rule would not cover:

- Low production well sites where the combine oil and natural gas production for the wells at the site is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production
- Existing well sites where additional drilling activities other than fracturing or refracturing (such as well workovers) are conducted on an existing well

In addition, well sites that only contain wellheads without ancillary equipment are not subject to the fugitive emissions monitoring requirements.

What requirements would apply?

Under the new proposed rule, EPA will require fugitive emissions surveys with optical gas imaging ("OGI") technology for new and modified well sites, as well as compressor stations. The proposal would require operators to conduct an initial survey within 30 days of commencing operation and semi-annual follow-up surveys. The proposal would require operators to replace or repair the sources of any detected fugitive emissions "as soon as practicable, but no later than 15 days after detection." All sources of fugitive emissions that are repaired must then be resurveyed within 15 days of repair completion to ensure the repair has been successful. Operators would be required to develop and implement company-wide monitoring plans to comply with these fugitive emission requirements.

The initial OGI survey of "fugitive emissions components" at the well site would include valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks. For new sites, the initial survey would have to be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, the initial survey would be required to be conducted within 30 days of the site modification. A modification occurs whenever a new well is added to the site, or anytime an existing well at the site is fractured or refractured.

Under the proposal, the survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during two consecutive surveys, but the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during two consecutive surveys. Monitoring frequency would continue to increase and decrease depending on the results of subsequent surveys. EPA is also considering a far more labor intensive and time consuming monitoring process, known as EPA Method 21.[2]

EPA is also requesting comments on criteria to evaluate corporate fugitive emission monitoring plans that could be deemed to meet the equivalent of its proposed standards as an alternative means of complying with its final rule. Companies with good internal fugitive policies may be able to reduce their compliance burdens by submitting thoughtful comments to EPA to encourage the agency to allow for these policies to serve as a way to comply with the proposed rule.

[2] Method 21 is a procedure used to detect VOC leaks for process equipment using a portable detecting instrument. Monitoring intervals vary accordingly to the applicable regulation, but are typically weekly, monthly, quarterly, and yearly. The monitoring interval depends on the component type and periodic leak rate for the component type." EPA, Leak Detection and Repair: A Best Practices Guide (2007), *available at* http://www2.epa.gov/sites/production/files/2014-02/documents/ldarguide.pdf

Record-keeping and Reporting

The proposal also contains record-keeping requirements related to the flowback time periods, and the total duration of venting, combustion and flaring over the flowback period for both subcategories of wells. The owner or operator would also be required to keep at least one digital photograph of each affected well site or compressor station for each monitoring survey, as well as logs with monitoring data related to fugitive emissions. In addition, the rule requires affected facilities to file an annual report consistent with the current requirements found in Subpart OOOO. In the proposal, EPA recognizes that this proposal could create duplicative recordkeeping and reporting requirements with Subpart W (requiring the monitoring and reporting of GHG emissions) and other state and local rules. EPA is soliciting comments on how it can minimize recordkeeping and reporting burden.

III. Midstream Impacts

The proposed NSPS provisions targeting the midstream business apply to compressor seals and compressor station fugitive emissions.

Standards for Centrifugal and Reciprocating Compressors

The proposed rule requires wet seal centrifugal compressors across the source category (except those located at a well site) to achieve 95 percent control efficiency by capturing and routing VOC and methane emissions to a combustion control device. Alternatively, the proposed rule will allow centrifugal compressors to use dry seal systems—which EPA determined to have substantially lower emissions than wet seal systems—or capture gas from centrifugal compressor seals and route it back to a low pressure fuel gas system.

For reciprocating compressors across the source category, EPA proposes an operational standard that will require owners or operators to replace rod packing systems every 26,000 hours of operation or every 36 months. As an alternative to rod packing replacement, the proposed rule would allow routing of emissions from the rod packing through a closed vent system under negative pressure. However, this technology may not be applicable to every installation, so EPA will allow operators to choose the control option for a particular application.

Fugitive Emissions (Compressor Stations)

As with the covered well sites, new and modified compressor stations across the source category (including the transmission and storage segment and the gathering and boosting segment) will be required to conduct semi-annual monitoring surveys using OGI and a resurvey using EPA Method 21. For purposes of the fugitive emissions provisions of the proposed standards, a modification occurs when one or more compressors is added to a compressor station after the effective date of the final rule, or when a physical change is made to an existing compressor that increases compressor capacity.

Any repairs needed must be completed within 15 calendar days and a resurvey of the compressor completed within 15 days of the repair. EPA has asked for comment whether this monitoring should be of the compressor or the facility as a whole. EPA believes that most regulated companies will contract for the performance of these surveys with contractors who are knowledgeable about OGI and have their own equipment. EPA is concerned that there may not be enough contractors and has requested comment on this point. EPA's proposed rule would relax the required frequency of subsequent surveys if the data shows fugitive emissions from less than one percent of their components. Conversely, the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their components.

The proposed rule defines the term “fugitive emission component” and includes a long list of components the operator must monitor, including valves, connectors, open-ended lines, pressure relief devices, closed-vent systems, and thief hatches on tanks. Equipment that vents natural gas as part of its normal operation is not considered “leaking” and is exempt. Operators will be required to repair any leaks discovered during the survey within 15 days, unless the repair would require shutting down production. If shutdown is required, then operators must repair any leaks during the next scheduled shutdown or within 6 months, whichever is earlier.

Requests for Comments

EPA is specifically requesting comments regarding a number of aspects of the proposed fugitive emissions requirements for compressors. Among the areas where EPA is specifically seeking comments are whether to adjust the baseline leak monitoring survey interval from semi-annually to annually or quarterly. In addition, EPA notes that Subpart W already requires certain compressor stations that emit more than 25,000 metric tons of CO_2e to submit annual fugitive emissions reports and will take comments regarding any reducing overlap between those requirements. EPA has requested comments on whether operators can perform the initial leak monitoring surveys using EPA Method 21 instead of OGI. EPA asked for comments on how voluntary, corporate leak detection programs could satisfy the requirements of the final rule.

IV. CTGs

Also on August 18, EPA issued draft Control Techniques Guidelines (“CTGs”) that, when finalized, will require states to consider imposing control requirements on existing oil and gas equipment in ozone nonattainment areas.

Section 182 of the Act requires states to revise their State Implementation Plans (“SIPs”) to include reasonably available control technology (“RACT”) requirements for existing sources of volatile organic compound (VOC, an ozone precursor) emissions in nonattainment areas. RACT is “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” A SIP is a state-adopted plan that demonstrates how a non-attainment area will achieve the national ambient air quality standards, such as the EPA’s standards for ozone.

These CTGs do not place any requirements on facilities. Instead, they serve as recommendations for state regulators to consider in setting RACT requirements for reducing VOC emissions in revised SIPs. States may use non-CTG technology and approaches, subject to EPA approval. The CTGs apply to pneumatic controllers, pneumatic pumps, compressors, equipment leaks and fugitive emissions in the onshore production and processing segments of the oil and natural gas industry, as well as storage vessels in all segments (except distribution) of the oil and natural gas industry. EPA considers the petroleum refining industry as separate from the oil and natural gas industry, so the CTGs do not apply to operations and equipment past the point of custody transfer at a petroleum refinery. Once EPA finalizes the CTGs, state regulators will have two years to submit SIP revisions to EPA for approval. EPA has not said when it intends to finalize the CTGs.

Because CTGs only apply in ozone nonattainment areas, the impact of these CTGs will be expanded when EPA finalizes its new ozone standard in October. If EPA drops the ozone standard from 75 ppb to between 65-70 ppb, as expected, EPA projects many areas of the country will be in non-attainment with the ozone standard for the first time. Eventually, there will be no limits to the coverage of existing sources based on ozone designations at all: Under Section 111(d) of the Act, EPA must issue existing source guidelines after it issues new source performance standards for “designated facilities,” such as upstream oil and gas facilities to be covered under the proposed rule. Although there is no fixed deadline for doing so, no doubt litigation will lead to a court-ordered deadline.

For example, EPA's draft RACT recommendation for storage vessels is a 95 percent reduction of VOCs from sources with a potential to emit greater than or equal to 6 tons per year annually. If that sounds identical to EPA's 2012 new source performance standards applicable to the same equipment, that's because it is: EPA acknowledged that some of its RACT recommendations mirror recent new source performance standards.

An overview of EPA's draft RACT recommendations is below.

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel.	95 percent reduction of VOC emissions from storage vessels with a potential to emit (PTE) greater than or equal to 6 tpy.
Pneumatic Controllers	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of zero scfh (unless there are functional needs, including but not limited to response time, safety and positive actuation, requiring a bleed rate greater than zero scfh).
	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs, including but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
Pneumatic Pumps	Individual natural gas-driven chemical/methanol and diaphragm pump located at a natural gas processing plant.	Zero natural gas emissions.
	Individual natural gas-driven chemical/methanol and diaphragm pump at locations other than natural gas processing plants from the wellhead to the point of custody transfer to the natural gas transmission and storage segment.	If there is an existing control device at the location of the pneumatic pump, reduce VOC emissions from each gas-driven chemical/methanol and diaphragm pump at the location by 95 percent or greater. If there is no existing control device at the location of the pneumatic pump, submit a certification that there is no device.

Emission Source	Applicability	RACT Recommendations
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing after 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent or greater.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants constructed or modified on or before August 23, 2011.
Fugitive Emissions	Individual well site with wells that produce, on average, greater than 15 barrel equivalents per day per well.	Implement a semiannual optical gas imaging (OGI) monitoring and repair program.
	Individual compressor station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Implement an OGI monitoring and repair program.

V. Definition of "Source" and "Aggregation"

While other aspects of the EPA's proposals would explicitly subject oil and gas operations to various emissions controls under the NSPS program, EPA's source aggregation proposal would potentially subject these operations to the costly and time-consuming air permitting requirements for construction and operation. Uncertainty about whether to aggregate individual activities in the oil field as a single source for purposes of deciding wither their collective emissions exceed permit applicability thresholds has led to litigation, including challenges by non-governmental organizations to projects, such as in the *Ultra Resources Inc*. challenge in Pennsylvania.[3] EPA is requesting comment on two approaches to defining what is a source for onshore oil and gas operations: one based solely on proximity, and another based on proximity within a certain distance and on functional interrelatedness beyond that distance. The more activities that EPA or state aggregate into a "source," of course, the more likely it is to be "major." EPA's approach to source aggregation exposes these oil and gas operations to the risk of time-consuming permitting obligations, including extensive and costly analyses of emissions, and even more stringent pollution controls.

Background

EPA's current permitting rules under the Act define a "source" as all activities (1) under common control, (2) within the same major industrial category, and (3) located on "contiguous or adjacent" properties. EPA is proposing to amend its Prevention of Significant Deterioration, Nonattainment New Source Review ("NSR"), and Title V program regulations to address its interpretation of adjacency, which courts have invalidated in a sequence of recent appellate court decisions. Over the years, various EPA memos and case-specific determinations had evolved the agency's definition of adjacency to include all emitting activities that were "functionally related" to a source, regardless of how geographically apart such activities may be from one another. The Sixth Circuit, in *Summit Petroleum Corp. v. U.S. Environmental Protection Agency*,[4] however, invalidated EPA's approach in 2012, holding that it was contrary to the plain meaning of "adjacent." Following this decision, EPA issued guidance calling for its "functional interrelatedness" test to be used in every state other than those in the Sixth Circuit (Kentucky, Michigan, Ohio, and Tennessee), but the D.C. Circuit invalidated that approach in 2014, holding that the guidance conflicted with EPA's rules requiring consistency across regions.

In order to resolve the uncertainty created by these developments, EPA has co-proposed two options for source aggregation in the oil and gas industry:

EPA's Preferred Option: Proximity

Under EPA's "preferred" option, a "source" in the oil and gas industry would include all the emitting activities located on a property, and only those sources that "are contiguous or are located within a short distance of one another" would be considered "adjacent." Under this option, EPA has proposed specifying that properties within a distance of ¼ mile should be considered a single source. This is the same distance within which certain states, including Texas, Pennsylvania, Oklahoma, and Louisiana, presume that operations should be considered a single source pursuant to state-issued guidance. EPA has requested comment on whether another distance, such as ½ mile, is more appropriate. A more troublesome question from EPA is whether it is appropriate to "daisy-chain" sources in the aggregation analysis; this artifice could extend the concept of a source quite broadly in geographic terms depending on how a project is structured. Louisiana has issued guidance stating that the aggregation analysis should not daisy-chain sources.

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[3] *Citizens for Pennsylvania's Future v. Ultra Resources, Inc.*, No. 4:11-CV-1360 (D. Md. Feb. 23, 2015).
[4] 690 F.3d 733 (6th Cir. 2012).

Option 2: Proximity Plus Functional Interrelatedness

Under EPA's second option, an oil and gas "source" would again include all the emitting activities located on a property, and properties within a proposed distance of ¼ mile. Sources beyond a ¼ mile could still be considered a single source and their emissions aggregated based exclusively on their functional interrelatedness. To define this amorphous concept, EPA has proposed that functional interrelatedness "might be shown" by a physical connection, such as a pipeline between equipment. EPA also provided "other examples of factors" on which it might determine sources to be functionally interrelated; this list is not defined explicitly, but EPA has suggested that considerations such as the delivery of product from one group of equipment to another, or whether one group of equipment is dependent upon the operation of another, could be the basis of a finding of functional interrelatedness. EPA is also seeking comment on whether functional interrelatedness in the oil and gas sector should be limited to certain common configurations of equipment, such as a "hub and spoke" production model. Finally, EPA is seeking comment on whether there is a distance beyond which sources should not be aggregated, even if functionally interrelated.

Analysis

Even EPA acknowledged the permitting burden that would be placed on operators and regulating authorities in its source-definition proposal: "it takes significantly longer to apply for and review a PSD application than it does to apply for and review a minor NSR permit." EPA estimates that a major source permit typically takes a year or more to process. Option 2 would be more time-consuming for permitting authorities, because it requires case-by-case determinations of the "functional interrelatedness" of sources separated by more than ¼ mile. Moreover, the outcome of such assessments remains highly uncertain, as it was under EPA's past approach to source aggregation; indeed, EPA's proposal does not specify a particular set of factors pursuant to which it proposes to assess functional interrelatedness. In addition to delays and higher costs, the ambiguity and case-by-case nature of the functional interrelatedness inquiry will also give non-governmental organizations an additional opportunity to challenge projects on criteria they may argue are determinative. Thus, permitting decisions under Option 2 would carry with them greater litigation risk, increasing uncertainty and the potential for delays.

VI. Conclusion

Upon publication in the *Federal Register*, EPA's proposals will be subject to a 60-day comment period. EPA will also hold public hearings on its source aggregation proposal at dates and locations to be announced in a forthcoming notice. EPA has indicated that if the rule is adopted as proposed, many of its requirements will apply retroactively based on construction and modifications after the date on which the proposal is published in the *Federal Register*, rather than taking effect 60 days after the final rule is adopted. Affected parties are therefore strongly encouraged to submit comments during the upcoming public comment period.

For more information, please contact Vinson & Elkins lawyers *Larry Nettles*, *George Wilkinson*, *Eric Groten*, *George C. Hopkins*, *Jay Rothrock*, *Corinne Snow*, *or one of the members of V&E's Shale and Fracking and Environmental practice groups.*