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REDUCING METHANE EMISSIONS FROM NATURAL GAS DEVELOPMENT: STRATEGIES FOR STATE-LEVEL POLICYMAKERS

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EXECUTIVE SUMMARY

The techniques of hydraulic fracturing and horizontal drilling, in combination, have opened up vast new areas for natural gas production, and low-cost natural gas has altered the energy landscape in the United States. Prior to the last decade, some states located in shale gas basins had little experience with significant oil and gas extraction, but are now among the leaders in the production of natural gas.[1] The rush to develop this new resource has resulted in numerous environmental challenges, including water and air quality concerns, leading many to question the natural gas industry's environmental record and potentially jeopardizing its social license to operate. Preventable emissions of methane—a potent greenhouse gas[2]—are among the easiest of those challenges to address, and policies that address those emissions have the co-benefit of reducing local air pollution.

Methane emissions are not a new phenomenon, but the pace of natural gas development in the United States has brought much deserved attention to the issue. According to the U.S. Energy Information Administration, marketed production of natural gas increased by 44 percent between 2005 and 2014, and is projected to increase another 30 percent or so by 2040.[3] If the United States is to develop its natural gas resource to such an extent, it is imperative to address the air quality, water quality, and climate concerns that such development will bring. Acknowledging the broader environmental impacts of natural gas development, this paper focuses on practical solutions that have been demonstrated to reduce methane emissions significantly without creating undue economic hardship for industry or consumers.

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Working Papers contain preliminary research, analysis, findings, and recommendations. They are circulated to stimulate timely discussion and critical feedback and to influence ongoing debate on emerging issues. Most working papers are eventually published in another form and their content may be revised.

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Reducing leakage over the natural gas lifecycle to one percent or less of total production is an achievable and cost-effective benchmark in the near term, and ensures that natural gas is less climate-intensive than diesel fuel and gasoline, when used in transportation, and coal when used for electricity generation.[4] Partly for this reason, Southwestern and other companies have founded the ONE Future Coalition, setting a one percent leakage rate target for their entire value chains.[5]

Some recent studies suggest that methane emissions from U.S. natural gas systems are more—and perhaps much more—than one percent of natural gas production at this time, though others have confirmed the estimates in the Environmental Protection Agency's (EPA) Greenhouse Gas Inventory.[6] State regulators and legislators have a number of tools at their disposal to help companies overcome market barriers to greater implementation of emissions-control technologies and achieve this benchmark;[7] which of these policy tools makes the most sense can vary by emissions source, the severity of the problem, or local conditions that might pose legal or political challenges.

Several federal agencies are taking some steps to reduce methane emissions. For example, Bureau of Land Management is undertaking a rulemaking to limit the venting or flaring of natural gas on federal lands.[8] And EPA has announced that it will propose standards for some new natural gas infrastructure in 2015, and will finalize those standards in 2016.[9] Because EPA is not addressing the significant methane emissions from existing infrastructure, states have the opportunity to achieve both deeper emissions reductions and public health benefits. Moreover, differing geologies and other local considerations make state-level policymakers uniquely well positioned to identify the solutions that work best within their jurisdictions. Also, in recent years, policymakers at the state level have led the way in addressing some of the largest sources of methane and other air pollutants from natural gas systems.[10] Yet there is still much more that states and the federal government can do to reduce the environmental and climate footprint of natural gas systems.

State oil and gas commissions issue permits for drilling and gathering lines, and can set performance standards for natural gas extraction. State air and environmental agencies implement air quality rules, which are of particular importance to the production and processing sectors. State regulatory agencies enforce safety regulations and other rules governing interstate transmission pipelines. Public utility commissions oversee the natural gas distribution system, and weigh the costs and benefits of emissions-reduction measures to ensure that ratepayers are not unduly burdened with higher costs.

Through case studies, key recommendations for new rules, and descriptions of best practices, this working paper can help state officials to determine how best to structure future state-level policies—including measures for complying with forthcoming national emissions standards under the Clean Air Act—to reduce methane emissions from natural gas development. The measures laid out in Table ES-1 are among the best practices for reducing methane emissions throughout the natural gas value chain, and can inform the development of new policies to limit such emissions. All of the measures listed should be paired with a rigorous monitoring and verification program, to ensure that all potential reductions are realized.

Table ES-1 | **Key Recommendations for Methane Emissions Reduction Policies**[11]

PRODUCTION, PROCESSING, AND TRANSMISSION		
SOURCE	**POLICY RECOMMENDATIONS AND BEST PRACTICES**	**PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013**[12]
Reciprocating Compressors		19
Seals	Replace rod packing systems every three years at existing compressors along transmission lines and on gathering and boosting lines, and require annual maintenance to ensure good working order. When appropriate measurement technology is available, states should ensure that emissions from reciprocal compressors are reduced to 11.5 standard cubic feet (scf) per hour—the average emissions from newly installed rod packing.[13] As an alternative compliance option, states could require the capture of leaking natural gas and its re-routing back into the compressor engine, to be combusted to power the compressor.	
Static Components	States should also require regular leak detection and repair (LDAR)[14] for compressors at processing plants and along gathering lines.	
Pneumatic Devices	States can go beyond the requirements set forth in Colorado's new rules targeting pneumatics by requiring the following: ■ retrofits of continuously or intermittently emitting high-bleed pneumatics (that is, devices that vent significant quantities of natural gas as part of their normal operations) with no-bleed or low-bleed equivalents as soon as practical, to bring their emissions down below a low-bleed threshold of six scf per hour,[15] ■ regular LDAR to identify excessively emitting equipment, which can be repaired or replaced, and ■ all new and replacement controllers upstream of the processing plant to be powered by compressed air or electricity instead of compressed gas when access to the electric grid is available, and with low-bleed pneumatics when it is not.	12
Liquids Unloading	Where external power sources or high-pressure gas are available, an artificial lift—powered either by electricity or gas—should be used during every unloading event. When external power sources are not available, plunger lifts should be used during every unloading event. Because plunger lifts have been demonstrated to reduce methane emissions by 95 percent or more when used properly, well operators should be required to use plunger lifts and avoid venting wherever feasible.[16] States should ensure that well operators are trained in best practices in order to maximize emissions reductions from liquids unloading events.	4

Table ES-1 | **Key Recommendations for Methane Emissions Reduction Policies[11] (continued)**

PRODUCTION, PROCESSING, AND TRANSMISSION		
SOURCE	**POLICY RECOMMENDATIONS AND BEST PRACTICES**	**PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[12]**
Equipment Leaks	States should require two-stage LDAR for all production facilities, processing plants, compressor stations, and large, above-ground distribution facilities. Mobile air monitoring—whereby air-sampling technology is mounted to a vehicle to check for high concentrations of methane—should be performed at least quarterly. States should phase in this requirement to allow companies to purchase or lease the appropriate emissions monitoring equipment. A complete leak detection survey using optical gas imaging (OGI) or portable analyzers should be performed semi-annually, to ensure that all leaks are detected. When mobile monitoring detects methane or Volatile Organic Compound (VOC) levels higher than background levels, follow-up OGI or portable analyzer screenings should be performed to locate the source of the leak. Once discovered, leaks should be repaired within five calendar days if possible. If the leak cannot be repaired within five days, either because needed parts are unavailable or because facility operations would need to be shut down, then repairs must be made within 15 calendar days, or as soon as practical.[17] Companies should report the results of their mobile monitoring surveys to the state, which can make those reports public, and state officials should ensure that all leaks have been repaired by performing spot checks of production, processing, and transmission facilities within their borders.	19[18]
Centrifugal Compressors		9
Seals	Performance standard for all existing centrifugal compressors of six scf per minute, which represents the average emissions factor for dry seal systems, and an 87 percent reduction below typical emissions levels from wet seal systems.[19] This standard can be met either by replacing wet seals with dry seals, or capturing gas leaked from wet seals (to be re-routed back to processing and later sold), the latter of which can reduce vented methane emissions from de-gassing seal oil by up to 99 percent.[20]	
Static Components	In conjunction with measures to reduce emissions from wet seal centrifugal compressors, all compressors should be subject to a rigorous LDAR program. As described above, and in greater detail below, states should implement a two-stage program, to increase the effectiveness of performing LDAR without burdening industry with unnecessarily high costs.	
Engine Exhaust	When an electric power supply is available from the grid, or on-site distributed generation is feasible, electric motor starters should be used for all engine start-ups. When this is not the case, gas starters should either be replaced with air or nitrogen, or operators should capture the gas used in the starters. As with centrifugal compressors, engines should be included in all LDAR surveys.	11
Pipeline Venting	For planned maintenance, pipeline operators must use portable compressors—either alone or in conjunction with in-line compressors located at the compressor station—to reduce pipeline pressure to 90 percent below normal operating levels. For emergency repairs, when there is not enough time to secure a portable compressor, maintenance teams should use in-line compressors to reduce pipeline pressure to 50 percent below normal operating levels (if doing so does not present a safety hazard).	3

Table ES-1 | **Key Recommendations for Methane Emissions Reduction Policies[11] (continued)**

DISTRIBUTION	
POLICY OPTION	**DESCRIPTION**
Pipeline Replacement Programs	State regulators should allow for accelerated pipeline replacement programs, which would likely require higher prices for gas customers. Regulators should ensure that lower-income households are not adversely affected by any price increase.
Leak Reclassification	State legislators or regulators should work with natural gas utilities to modify the existing system of leak classification, which does not assign a high priority to repairing large leaks that do not pose a threat to people or property. Such leaks should be categorized as Tier 2, and should be repaired within a reasonable amount of time (for example, three months or less).
Leak Inspection	Utilities should be required to use vehicle-mounted emissions detection equipment to survey their entire network of distribution pipelines at least twice per year.
Meter Replacement	To reduce the quantity of gas that is "lost and unaccounted for" between the city gate and end-users, residential and commercial meters should be tested for accuracy at least once every seven years.[21] If flow accuracy is found to have fallen below 98 percent, the meter should be replaced.

INTRODUCTION

As the shale gas boom opens up new areas for natural gas development, states that have long been unaccustomed to significant oil and natural gas development are confronting the need to regulate those industries for the first time.[22] Numerous challenges—from wastewater disposal to smog and other air quality concerns—must be overcome to protect the public interest and to enable natural gas companies to retain their social license to operate. Among those challenges, the issue of methane emissions from natural gas production, processing, and transmission is perhaps the easiest to address (see Table 2 for emissions sources by supply chain segment). Well-designed policies can reduce unnecessary leaks and vents of methane, minimizing the waste of a valuable resource and saving the industry money while simultaneously reducing other forms of air pollution as a co-benefit.

Methane, the primary component of natural gas, is a potent greenhouse gas, with 36 times the heat-trapping power of carbon dioxide over 100 years.[23] How much methane is leaking into the atmosphere from natural gas infrastructure is not yet known, but even the lowest estimates indicate that methane emissions are a significant problem, and one that will only grow larger with increased natural gas production unless further emissions-control policies or incentives are introduced (See Box 1 for a discussion of forthcoming standards from the Environmental Protection Agency (EPA) that address emissions from new sources).[24] Leakage rate estimates vary widely.[25] EPA's 2015 Greenhouse Gas Inventory suggests around 1.2 percent of natural gas is lost between the well and the end user. However, a number of studies propose that EPA might be significantly understating the magnitude of the problem, and suggest leakage rates at least 50 percent higher than EPA estimates, with considerable regional variations.[26]

Many natural gas leaks emit both methane and other pollutants. Before natural gas is processed to strip out many of the impurities, it is composed of roughly 70-90 percent methane, and 10–30 percent ethane, propane, and other volatile organic compounds (VOCs) and hazardous air pollutants (HAPs).[27] VOCs are precursors to smog formation, and HAPs include carcinogenic chemicals such as benzene. Because of the public health and air quality consequences of VOC and HAP emissions, most policies that address emissions sources upstream of the processing plant have, to date, focused on VOCs or HAPs, with reductions of methane emissions seen as co-benefits.[28] After processing, natural gas is roughly 95 percent methane, on average, and leaks and vents of natural gas release far fewer non-methane pollutants.[29] Therefore, to ensure deep reductions of methane emissions, it is critically important to target methane directly, because the current focus on VOCs or HAPs misses many significant sources of methane emissions in the transmission, storage, and distribution segments of the value chain.

Table 1 | **Major Emissions Sources by Supply Chain Segment**

EMISSIONS SOURCE	PREPRODUCTION AND PRODUCTION	PROCESSING	TRANSMISSION	DISTRIBUTION
Reciprocating Compressors	✓	✓	✓	
Centrifugal Compressors		✓	✓	
Pneumatic Devices	✓	✓	✓	
Liquids Unloading	✓			
Equipment Leaks	✓	✓	✓	✓
Engines	✓	✓	✓	
Pipeline Vents			✓	

Policies that target methane-emissions reductions directly are good for the climate and local environment, but they can also be good economics.[30] Consider the following:

Reducing the waste of a valuable commodity pays dividends for companies in the form of higher revenues, and investments in emissions-control technologies often pay for themselves in three years or less, as discussed in more detail below.[31]

Reducing methane emissions creates high-quality jobs, because dozens of companies manufacture emissions-control equipment in the United States.[32]

In the case of natural gas operations on public lands, reducing leaks and vents of natural gas means more royalties and a better value for taxpayers.[33]

Reducing natural gas leakage to one percent or less of total production is an achievable and cost-effective[34] benchmark for the near term, and ensures that natural gas is less climate-intensive than its substitutes for all end-uses, namely diesel fuel and gasoline in the transportation sector, and coal in electricity generation.[35] A number of regulatory, legislative, and incentive-based approaches are available to policymakers and to businesses to help the U.S. natural gas industry achieve this benchmark. Which approach makes the most sense can vary by emissions source, the severity of the problem, or local conditions that might pose implementation challenges, including resource, legal or political issues.

In this working paper, we examine the major sources of methane emissions from the production, processing, transmission, and distribution of natural gas (see Figure 1), as well as the technologies and procedures available now to reduce their negative environmental and climate impacts. Studies indicate that a small percentage of sources might be responsible for a large percentage of methane emissions.[36] The varying nature of methane emissions from natural gas systems means that there is no "one size fits all" approach that will work in every instance. However, policy solutions based on established best practices can effectively address each of the problems we discuss below.

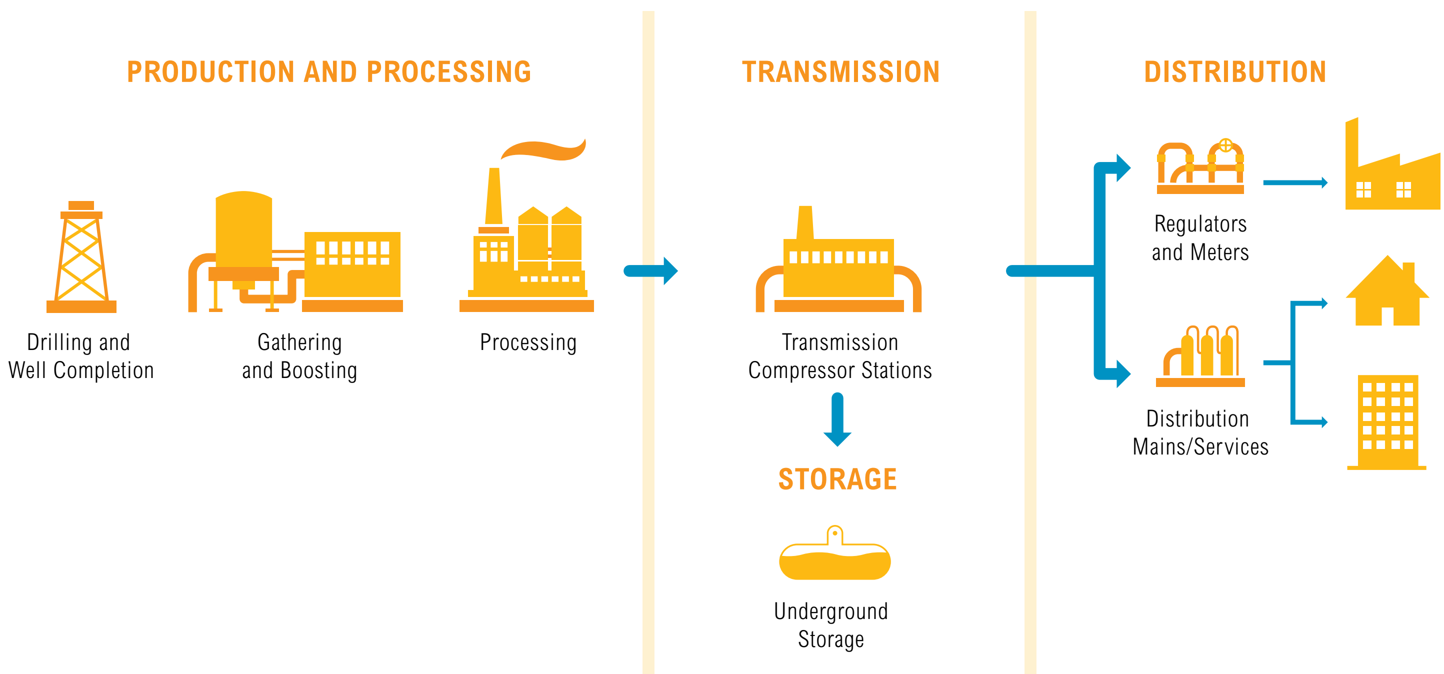
Box 1 | Potential National Methane Standards from EPA

On March 28, 2014 the Obama Administration announced its "Strategy to Reduce Methane Emissions" as part of the president's Climate Action Plan.[37] Along with updating standards for methane emissions from landfills, and potential new requirements for capturing and selling methane from coal mined on public lands, the president directed EPA to consider new standards for methane emissions from oil and gas development. Unlike the earlier New Source Performance Standard (NSPS), which addressed VOC emissions but reduced methane emissions as a co-benefit, these new standards would target methane directly, most likely under Section 111 of the Clean Air Act.[38]

Several weeks later, EPA released a series of white papers for public comment, covering methane emissions from compressors, well completions, leaks, liquids unloading, and pneumatic devices.[39] These white papers, along with stakeholder comments, are likely to form the basis of new emissions standards that will, according to EPA, be proposed in the second half of 2015. At the time of publication of this working paper, EPA had not yet announced a decision on which of these sources, if any, would be addressed via new rules, nor how stringent those rules should be. What the administration has said is that these rules will target only new and modified infrastructure and that, together with voluntary efforts, they will reduce methane emissions from the oil and gas sector to 40-45 percent below 2012 levels by 2025.[40]

While more stringent federal standards would necessarily supersede weaker state standards for the same emissions source, states nevertheless need to move forward with crafting their own methane rules for the emissions sources discussed in this working paper. This is because, first and most importantly, the forthcoming emissions standards from EPA focus exclusively on new and modified infrastructure, and will miss a substantial fraction of total emissions from old and leaky equipment. Second, as mentioned above, many if not most of the technological solutions available for addressing these sources are cost-effective and pay for themselves in three years or less.[41] Third, under Section 111, states are required to implement and enforce compliance with any federal emissions standard that EPA may propose. By embarking on the learning curve before federal rules are finalized, states can reduce any potential compliance costs borne by companies operating within their borders. Lastly, we don't yet know how stringent any of EPA's new rules will be, and it is unlikely that they will cover all of the emissions sources discussed in this working paper, providing states the opportunity to help reduce waste and save money for the natural gas industry and consumers.

Figure 1 | The Natural Gas Supply Chain



Source: http://www.epa.gov/ghgreporting/images/subpart_w_chart.jpg.

We have chosen to make policymakers at the state level, including state legislators, public utility commissioners, and other regulatory agencies, the primary focus of the recommendations in this working paper. States have a traditional role as "laboratories of democracy," whereby successful policies at the state level are emulated in other states and at the federal level.[42] In addition, it will be important for states to go beyond EPA's proposed standards for new and modified equipment if they are to address the substantial emissions from existing infrastructure. As of this writing, EPA is considering regulating methane from major sources under Section 111 of the Clean Air Act.[43] Under this framework, EPA sets state-level targets, and then works with states to find ways in which the targets can be met (see Box 2 for more details).[44]

Box 2 | **EPA Rules Draw on State Experiences**

In 2012, EPA promulgated an NSPS that addressed one of the largest sources of methane and VOC emissions in the production segment, namely, natural gas well completions.[45] In brief, well completion is the process by which a drilled well is made ready for the production of natural gas, and the flow of natural gas expels drilling and other fluids. Throughout this process, natural gas has traditionally been vented to the atmosphere or flared. However, EPA's NSPS requires new and refractured wells to reduce VOC emissions from well completions. Well operators were allowed to meet this requirement through flaring until January 2015; now, most natural gas vented during completions must be captured, a process called "green completion."

EPA's decision to target well completions did not happen in a vacuum. Rather, the agency followed the successful implementation of similar rules in both Wyoming and Colorado. Wyoming, for example, had been mandating green completions in most instances since 2004, requiring that well operators divert gas that would otherwise have been vented into sales lines.[46] This proof of concept at the state level provided EPA with rules it could build on and served as the basis for the national emissions standards issued in 2012.[47]

States have long served as laboratories and proving grounds for policies that later get adopted by other states and by the federal government. States that implement strong measures to reduce methane emissions from natural gas development also have the advantage of shortening the learning curve if and when methane emissions are regulated at the national level. Companies active within those states with ambitious methane reduction measures will be better prepared to meet national standards, and will likely benefit from lower compliance costs and increased returns on investment in emissions reduction training and equipment.

This working paper builds on earlier work by WRI, as well as studies from the Environmental Defense Fund, Natural Resources Defense Council, academic researchers, ICF International, the National Oceanic and Atmospheric Administration, EPA, and others. It presents a clear overview of what is known about methane emissions from natural gas systems and how they can be mitigated. Through case studies and descriptions of best practices, this working paper proposes recommendations for new rules. This paper can help EPA and states determine how best to structure future policies to reduce methane emissions from natural gas development.

EMISSIONS REDUCTION OPPORTUNITIES DURING THE PREPRODUCTION AND PRODUCTION STAGES

Drilling wells, preparing them for production, ensuring a steady flow of gas, and transporting the gas from the wellhead to the processing plant involves a number of procedures and pieces of equipment that can emit significant quantities of methane if not adequately addressed. In this section, we will examine some of the largest sources of those emissions at this first stage of the natural gas supply chain and recommend policies that states can put in place to ensure the use of best practices.

Reciprocating Compressor Seals

Compressors increase pressure to move natural gas from the well all the way to the city gate; they are used in the production stage of the supply chain to move gas through gathering lines to the processing plant.[48] Many compressors are powered by the natural gas that flows through the lines they are pressurizing, which opens the door to unintentional vents and leaks from seals, valves, gaskets, and other components.

Two primary types of compressors are used at various points in the natural gas supply chain. In the production stage, reciprocating compressors are the most common, and so are discussed here; centrifugal compressors are more common in the processing and transmission stages, and are discussed below.[49] Reciprocating compressors work by using pistons on a crankshaft to compress natural gas, thereby increasing pressure and facilitating the movement of gas along gathering or boosting lines.

EPA's NSPS requires regular maintenance of new reciprocating compressors at gathering and boosting stations and processing plants to reduce methane emissions. Operators must replace rod packing systems, which can wear down and leak methane, every 36 months or 26,000 hours of operation. However, the NSPS does not apply to existing compressors.[50] Reciprocating processors in the production stage were the source of around 46,000 metric tons of methane emissions in 2013, or 1.5 million metric tons of CO_2 equivalent.[51,52] While this is only around 2.5 percent of all production emissions, the NSPS and other sources demonstrate that regular compressor maintenance is good business practice. Replacing rod packing systems at reciprocating compressors on gathering and boosting lines every three years costs between $4,000 and $7,000, and saves an average of around 400,000 cubic feet (400 Mcf) of natural gas per compressor per year.[53] At natural gas prices of $4.50 per Mcf, slightly higher than the average daily spot price for 2014, a policy requiring compressor maintenance every year and rod packing replacement every three years would pay for itself in added revenue.[54]

Pneumatic Devices

Pneumatic devices, powered by natural gas, regulate various aspects of the gas passing through them, including temperature, pressure, and flow rate. Many pneumatics are powered by natural gas under high pressure, and vent (or "bleed") some of that gas to the atmosphere as part of normal operations. High-bleed pneumatic devices are a significant source of methane emissions throughout the supply chain, but low-bleed and no-bleed substitutes are currently available.

As with compressors, the EPA NSPS addresses emissions only from new pneumatic devices, not from existing equipment. Yet existing devices number over half a million and are a significant source of methane emissions.[55] According to EPA Inventory data, in 2013, pneumatics emitted roughly 638,000 metric tons of methane, over 20 million metric tons of CO_2 equivalent, or a full one-third of all methane emissions from the production sector.[56] It should be noted, however, that at least one study suggests that EPA might be underestimating these emissions by over 40 percent.[57]

Replacing or retrofitting a continuously or intermittently emitting high-bleed controller—defined as emitting an average of over six standard cubic feet (scf) per hour as part of normal operations—can make economic sense even if the device is not yet at the end of its useful life.[58] With retrofit and replacement costs ranging from a few hundred to a few thousand dollars, respectively, low-bleed pneumatic devices can pay for themselves through increased revenues in three years or less.[59] An alternative solution that eliminates methane emissions altogether is to replace gas-driven pneumatic devices with ones that rely on compressed air or electricity instead, as is common in processing plants and at some production facilities with access to the electric grid or on-site electricity generation.[60] Despite a more significant up-front investment, instrument air devices are also reported to reduce quantities of leaked natural gas by amounts sufficient to pay for the devices in two years or less.[61]

Box 3 | Pneumatic Devices in Colorado

Colorado had rules in place in 2009, well before the EPA NSPS was first proposed, that required the use of low-bleed pneumatics at new installations, and the replacement or retrofitting of existing high-bleed pneumatics to bring their emissions down to levels achieved by low-bleed pneumatics.[62] However, these rules targeted VOCs, and applied only in areas with high levels of ground-level ozone, or smog.

In 2014, these same standards were updated to apply statewide, and while they still target VOCs, they will have significant methane co-benefits.[63] With very few exceptions, low-bleed or no-bleed pneumatics must be installed at new installations, and high-bleed pneumatics must be replaced or retrofitted by May 2015. In areas where grid electricity is available, no-bleed pneumatics, which are powered by compressed air or electricity and do not vent natural gas to the atmosphere as part of normal operations, can be used to comply with this requirement.

While Colorado's requirements for pneumatic devices set an example for other states and the federal government to follow, they can be strengthened still further without sacrificing cost-effectiveness. Because they target VOCs, Colorado's rules apply only to pneumatic devices upstream of the processing plant—that is, only within the production segment of the natural gas supply chain. However, pneumatics are used throughout the supply chain, including downstream of the processing plant where VOC concentrations are lower. States should expand Colorado's standards to all pneumatic devices, and ensure they target methane directly in order to capture all high-bleed devices.

Liquids Unloading

Over time, water and other fluids (including natural gas liquids, like propane) can accumulate in natural gas wells, reducing pressure in the well and impeding the flow of natural gas. To increase the production of a mature well, these liquids can be removed (or "unloaded") in a number of ways, many of which lead to intentional or unintentional venting of natural gas to the atmosphere. One such method, well blowdowns, involves shutting in the well, allowing pressure to build, and then opening the valve at the surface to drive the liquids from the wellbore (while venting gas to the atmosphere). However, this method is often a temporary fix, doing little to solve the underlying problem of accumulated liquids, and leading to lower production over the lifetime of the well.[64]

As is the case with many other sources in the natural gas supply chain, methane emissions from liquids unloadings appear to follow a "fat-tail" distribution, in which a small fraction of wells with more frequent unloadings are responsible for a large fraction of emissions.[65] The 2015 EPA Inventory estimates that unloadings—both with and without plunger lifts—accounted for over 259,000 metric tons of methane emissions in 2013, or 14 percent of emissions from the production segment of the natural gas life cycle;[66] this is in line with estimates from the Greenhouse Gas Reporting Program from that year.[67] Yet both of these estimates use emissions factors from an industry survey, not an independent analysis that includes a representative cross-section of the natural gas industry; they therefore should be taken as a conservative estimate.[68]

Several techniques use energy from the well or from outside sources to lift the liquids to the surface, increasing the flow and production of natural gas without unnecessary venting.[69] For example, plunger lifts use the pressure within the well to depress a plunger to where liquids are accumulated, pushing them up to the surface.[70] Plunger lifts have proven to be extremely cost-effective in many instances, especially when used correctly and when venting is minimized, with payback periods of less than one year.[71] And if an external power source is available, artificial lifts that are powered by electricity instead of the well's internal pressure can be used to pump liquids to the surface, reducing the need for extraneous venting.[72] Because artificial lifts have proven to be more effective at removing liquids with few to no methane emissions (though the equipment does generate some emissions of carbon dioxide), they should be used at wells being unloaded for the first time, and for all subsequent unloadings, if feasible.[73]

Equipment Leaks

Equipment leaks cut across all major segments of the industry (production, processing, transmission, and distribution), and overlap with many other major source categories (such as compressors, described above). Traditionally, the category of leaks has been defined to include unintentional emissions from a variety of equipment, including connection points such as flanges, open-ended lines, fittings, and moving parts of valves, pumps, and compressors.[74] The category does not include intentional venting of gases, such as venting from well completions and liquids unloading.

In this section we take a broad definition of LDAR and discuss how policy responses focused on equipment leaks can also aid in the detection of excessive emissions from equipment across all source categories.

Existing national regulation (EPA NSPS) requires leak detection and repair for certain components including pumps, valves, and pressure-relief devices at new natural gas processing facilities.[75] The recent update to the EPA standards tightened the LDAR requirements for processing plants by lowering the detection limit of leaking gas from valves from 10,000 to 500 parts per million, and added connectors to the list of components to monitor. The rule was based on analysis showing that LDAR programs were most cost-effective at natural gas processing facilities (using EPA's leak detection protocol, Method 21—see below).

As recently documented by EPA's White Paper on the topic, a wide range of evidence is available that demonstrates the pervasiveness of equipment leaks throughout all segments of the natural gas system.[76] This evidence includes mandatory reporting data, studies of voluntary LDAR programs, and measurement campaigns. In general, the balance of evidence shows that gas processing plants have the highest leak rates, followed by compressor stations and well production sites, and that a large proportion of total emissions (approximately 80 percent) comes from a small proportion of leaks (approximately 20 percent).[77] Importantly, the current state of knowledge suggests that these disproportionately large leaks are not related to any specific types of operators or operating parameters,[78] meaning that widespread LDAR can be highly cost-effective, and is needed throughout the industry to find and fix these "super emitters."

While a wide variety of equipment is available for implementing LDAR, federal and state policymakers have focused mainly on two methods: portable analyzers (also called EPA Method 21) and optical gas imaging (OGI, also known as infrared imaging). While OGI devices have a much higher capital cost (around $85,000 *versus* $10,000 for a portable analyzer),[79] they can monitor equipment at a much higher rate than is possible with portable analyzers. This allows their higher upfront cost to be spread across a number of facilities, and opens the door to alternative business models such as renting equipment or purchasing leak detection services from third parties. OGI has other advantages. For example, it can monitor inaccessible components (such as storage tanks) at a distance and find leaks quickly in places where surveyors may not have thought to look, such as underground pipelines outside of processing plants. On the other hand, unlike portable analyzers, OGI devices cannot definitively identify the gases that are leaking or quantify the size of leaks, only detect them.

The cost-effectiveness of LDAR programs using either technology depends on a number of factors, including the amount and value of gas that otherwise would have leaked, and the cost of the program (equipment, training and labor for leak detection, plus the cost of repairing the leaks). The available evidence shows that it is cost-effective to repair the vast majority of leaks, and the cost of conducting the surveys is the primary hurdle for either voluntary or regulatory LDAR programs.[80]

A critical parameter is how often facilities conduct these surveys. Too few surveys per year will allow valuable gas to escape, but too many could result in only marginal improvements in emissions reductions. Recent work analyzing thousands of LDAR surveys has shown that the sweet spot is likely to be between monthly surveys and semiannual surveys, depending on the life-cycle segment, size of the facility, potential for emissions, existing maintenance programs, and other factors.[81] Critically, most of the available evidence on cost-effectiveness is related to facilities already performing regular LDAR. Since equipment leaks seem to follow the 80/20 rule, this suggests that, on average, the cost-effectiveness of regular LDAR regimens will be much greater at facilities not yet performing regular LDAR. It is likely that operators currently conducting regular LDAR surveys have fewer and smaller leaks than those who are not, because they have been detecting and fixing leaks all along.

We should note that significant efforts are underway to improve and reduce the cost of technology for leak detection. For instance, vehicle-mounted monitoring at the site level is a relatively recent innovation, giving operators the opportunity to take a rough scan of a facility before deciding whether to conduct a full leak survey, saving time and money if the potential emissions sources are well maintained and not leaking.[82] Further, the MONITOR program of the Advanced Research Projects Agency-Energy (ARPA-E) and the Environmental Defense Fund's Methane Detectors Challenge are likely to lead to new and more cost-effective leak detection technologies in the 5–10 and 2-3 year timeframe, respectively. These developments imply that policies should be both open to new technologies and designed based on the cost-effectiveness of LDAR today, which will lead to even more cost-effective LDAR in the future.[83]

As discussed above, existing regulations for VOCs and hazardous air pollutants are in place for natural gas processing facilities and provide methane reduction co-benefits. However, leaders in both Colorado and Wyoming have gone beyond these national requirements to require LDAR at upstream production facilities as well, and recent Colorado regulations also require LDAR at upstream compressor stations and for storage vessels.[84] Both states allow use of either OGI or Method 21 approaches.

Box 4 | Four States Take the Lead on Leak Detection and Repair

In February 2014, with support from some of the largest natural gas companies in the state, Colorado finalized new rules mandating LDAR at well sites, gathering compressor stations, and storage vessels.[85] The inspection frequency varies from monthly to annually for most facilities, depending on the type of equipment and the potential emissions from the site.[86] This flexibility helps keep compliance costs down while ensuring that the sources of the largest potential leaks—and therefore the ones most cost-effective to repair—are monitored more frequently than sources that are less likely to be major emitters. The new rules require all leaks to be repaired within five days, unless parts are unavailable or shutdown is required to fix the leak. In the former case, companies are given 15 days to repair the leak and to prove that the leak was fixed after 15 days. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.[87]

In developing its LDAR rules for production facilities, compressor stations, and storage tanks, Colorado learned from the experiences of Pennsylvania and Wyoming in requiring regular leak detection and repair surveys.[88, 89] Just two months after Colorado finalized its rules, and five months after they were first proposed in November 2013, Ohio followed suit with new LDAR requirements of its own.[90]

This example illustrates how states can learn from one another, even if they do not directly collaborate on developing rules. Similarly, other states can follow the examples of Pennsylvania, Ohio, Colorado, and Wyoming, strengthening the rules where appropriate (for example, increasing the frequency of leak inspections) to better protect human health, the local environment, and the climate.

Table 2 | **Key Recommendations for Production Stage Policies**

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[91]
Reciprocating Compressors		19
Seals	Replace rod packing systems every three years at existing compressors along transmission lines and on gathering and boosting lines, and require annual maintenance to ensure good working order. When appropriate measurement technology is available, states should ensure that emissions from reciprocal compressors are reduced to 11.5 standard cubic feet (scf) per hour—the average emissions from newly installed rod packing.[92] As an alternative compliance option, states could require the capture of leaking natural gas and its re-routing back into the compressor engine, to be combusted to power the compressor.	
Static Components	States should also require regular leak detection and repair (LDAR)[93] for compressors along gathering lines and at processing plants.	
Pneumatic Devices	States can go beyond the requirements set forth in Colorado's new rules targeting pneumatics by requiring the following: ■ retrofits of continuously or intermittently emitting high-bleed pneumatics (that is, devices that vent significant quantities of natural gas as part of their normal operations) with no-bleed or low-bleed equivalents as soon as practical, to bring their emissions down below a low-bleed threshold of six scf per hour,[94] ■ regular LDAR to identify excessively emitting equipment, which can be repaired or replaced, and ■ all new and replacement controllers upstream of the processing plant to be powered by compressed air or electricity instead of compressed gas when access to the electric grid is available, and with low-bleed pneumatics when it is not.	12
Liquids Unloading	Where external power sources or high-pressure gas are available, an artificial lift—powered either by electricity or gas—should be used during every unloading event. When external power sources are not available, plunger lifts should be used during every unloading event. Because plunger lifts have been demonstrated to reduce methane emissions by 95 percent or more when used properly, well operators should be required to use plunger lifts and avoid venting wherever feasible.[95] States should ensure that well operators are trained in best practices in order to maximize emissions reductions from liquids unloading events.	4
Equipment Leaks	States should require two-stage LDAR for all production facilities, processing plants, compressor stations, and large, above-ground distribution facilities. Mobile air monitoring—whereby air-sampling technology is mounted to a vehicle to check for high concentrations of methane—should be performed at least quarterly. States should phase in this requirement to allow companies to purchase or lease the appropriate emissions-monitoring equipment. A complete leak detection survey using optical gas imaging (OGI) or portable analyzers should be performed semi-annually to ensure that all leaks are detected. When mobile monitoring detects methane or VOC levels higher than background levels, follow-up OGI or portable analyzer screenings should be performed to locate the source of the leak. Once discovered, leaks should be repaired within five calendar days if possible. If the leak cannot be repaired within five days, either because needed parts are unavailable or because facility operations would need to be shut down, then repairs must be made within 15 calendar days, or as soon as practical.[96] Companies should report the results of their mobile monitoring surveys to the state, which can make those reports public, and state officials should ensure that all leaks have been repaired by performing spot checks of production, processing, and transmission facilities within their borders.	19[97]

EPA currently requires LDAR at new processing plants. However, expanding these standards to cover existing processing plants, as well as new and existing compressor stations and production and gathering facilities, is an important step toward reining in both methane and VOC/HAP pollution. As the Colorado rulemaking shows, LDAR can be a cost-effective measure in all segments of the natural gas production chain, and it is likely that its cost-effectiveness is higher for existing facilities where maintenance issues can be more frequent or problematic than at new facilities.

That said, it is important for state decision-makers to design policies that are flexible enough to accommodate the likely innovation coming soon in natural gas leak detection. An intriguing possibility today is the concept of two-stage LDAR, where initial mobile monitoring is used at production, processing, and transmission facilities to identify whether natural gas is leaking, followed by full LDAR at positively identified sites to pinpoint exactly where those leaks are occurring. Two-stage LDAR can be a highly effective method for reducing methane emissions, and rules should be designed to maximize reductions while keeping compliance costs in check. This could entail requiring mobile monitoring at a relatively high frequency (for example, monthly or quarterly) and full LDAR using OGI or Method 21 less frequently (annually or semiannually), and only when sites are identified as leaking by mobile monitoring. Further, while LDAR is cost-effective today, regulations should not be overly prescriptive about technology. Room must be left for future innovative monitoring and leak detection technologies to emerge as alternative compliance mechanisms.

EMISSIONS REDUCTION OPPORTUNITIES DURING THE PROCESSING STAGE

After production, unprocessed natural gas is moved along gathering lines from the wellhead to a central processing plant. When it comes out of the ground, natural gas is typically between 70 and 95 percent methane, meaning up to 30 percent of unprocessed natural gas can be liquids or gases that alter the energy content or reduce the purity or value of the natural gas.[98] For example, water and hydrogen sulfide can corrode pipelines, and gases like nitrogen reduce the energy content of natural gas. In addition, processing separates out natural gas liquids like propane and butane—valuable by-products that are sold separately from the natural gas itself.

Processing plants often use reciprocating compressors, and a variety of other equipment, that can leak if not maintained properly; policies to address both of these sources were discussed in the preceding section.

Centrifugal Compressors

Much larger than reciprocating compressors, centrifugal compressors nevertheless serve much the same purpose, namely, ensuring that natural gas remains pressurized so that it will move quickly through pipelines. The primary source of methane emissions from centrifugal compressors is from seals around the rotating shaft, which are designed to prevent gas from leaking. However, there are two types of seals—wet and dry—and wet seals have been found to leak considerably more than dry seals.[99] Wet seals use oil as a barrier to prevent the leakage of natural gas from the compressor; however, pressurized gas is absorbed by the oil, rendering it less effective as a barrier.[100] Contaminated oil is re-circulated, at which time the absorbed gas is vented to the atmosphere, flared, or re-routed back into the processing plant to remove accumulated impurities. By contrast, dry seals are mechanical and do not use oil, which leads to fewer and smaller leaks, as well as lower operating costs for plant owners.[101]

EPA's 2012 NSPS requires new and modified wet seal centrifugal compressors at processing plants to reduce VOC emissions by 95 percent,[102] which should lead to concomitant reductions in methane emissions. However, the rule does not cover existing centrifugal compressors, which are, and will continue to be, major sources of methane emissions at processing plants. According to the 2015 EPA Inventory, centrifugal compressors were responsible for as much as 283,000 metric tons of methane emissions in 2013 (10.2 million metric tons of CO_2 equivalent), nearly 85 percent of which came from compressors with wet seals.[103] However, information from EPA's Greenhouse Gas Reporting Program suggests that the emissions factor for wet seal compressors used in the Inventory may be a significant underestimate, and actual emissions could be much higher.[104]

Wet seal centrifugal compressors are more prevalent than dry seal compressors. According to the 2015 EPA Inventory, wet seal compressors make up 80 percent of the centrifugal compressors in the processing and transmission life cycle stages.[105] Operators of wet seal compressors have two available options to reduce methane emissions: retrofitting with dry seals, or installing equipment to capture and re-route gas that would otherwise be vented or flared. Retrofitting with dry seals can be expensive, but has been shown to produce positive returns on the initial investment within three years.[106] Gas capture systems have proven to be even more cost-effective.[107] Both options can reduce methane emissions from wet seals by 85 percent or more.

Reducing methane emissions from seals is a necessary but not sufficient step in addressing emissions from compressors as a whole. In addition to emissions from seals, which can be addressed through the measures described above, centrifugal compressors can leak potentially significant amounts of natural gas from valves and other components.[108] For this reason, best practice is to combine any actions to reduce emissions from wet seals with a rigorous LDAR program, to ensure that all major leaks are found and fixed within a reasonable amount of time.

Engines

Gas-burning engines are used throughout the natural gas supply chain to power compressors and other types of equipment, including reciprocating and centrifugal compressors at processing plants and at compressor stations along transmission pipelines. Unburned natural gas is often vented to the atmosphere, because of incomplete combustion, which occurs especially during engine startups.

Methane emissions associated with gas engines at processing plants totaled nearly 300,000 metric tons in 2013, or roughly 10.7 million metric tons of CO_2 equivalent.[109] If natural gas production and associated emissions continue to grow over the coming years, leaked and vented natural gas from engines throughout the natural gas supply chain could reach over 22 billion cubic feet (nearly 500,000 metric tons of methane) by 2018—worth approximately $100 million at average daily spot prices in 2014.[110]

While chemical solutions exist to reduce much of the air pollution associated with uncontrolled natural gas emissions from engine exhaust (for example catalytic reduction or oxidation), such measures unfortunately do not prevent methane from venting to the atmosphere.[111] However, mechanical solutions are available to help reduce unnecessary venting from engines. For example, replacing pressurized natural gas used in engine start-ups with compressed air or nitrogen can reduce methane emissions from vented natural gas, as well as leaks from storage tanks.[112] Alternatively, using an electric motor instead of a natural gas engine can avoid methane emissions from engine start-ups altogether.[113]

Table 3 | **Key Recommendations for Processing Stage Policies**

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[114]
Centrifugal Compressors		9
Seals	Performance standard of six scf per minute for all existing centrifugal compressors, which represents the average emissions factor for dry seal systems, and an 87 percent reduction below typical emissions levels from wet seal systems.[115] This standard can be met either by replacing wet seals with dry seals, or capturing gas leaked from wet seals (to be re-routed back to processing and later sold), the latter of which can reduce vented methane emissions from de-gassing seal oil by up to 99 percent.[116]	
Static Components	In conjunction with measures to reduce emissions from wet seal centrifugal compressors, all compressors should be subject to a rigorous LDAR program. As described above, and in greater detail below, states should implement a two-stage program, to increase the effectiveness of performing LDAR without burdening industry with unnecessarily high costs.	
Engine Exhaust	When an electric power supply is available from the grid, or on-site distributed generation is feasible, electric motor starters should be used for all engine start-ups. When this is not the case, gas starters should either be replaced with air or nitrogen, or operators should capture the gas used in the starters. As with centrifugal compressors, engines should be included in all LDAR surveys.	11

EMISSIONS REDUCTION OPPORTUNITIES DURING THE TRANSMISSION STAGE

The transmission segment of the natural gas supply chain includes interstate and intrastate pipelines, as well as compressor stations that help maintain the pressure of the natural gas inside those pipelines. Compressor stations contain much of the same equipment that we have discussed already, including reciprocating and centrifugal compressors, engines, and pneumatic devices. This equipment is a major source of emissions at compressor stations, as it is elsewhere. (See the Production and Processing sections of this working paper for more information on emissions sources earlier in the natural gas supply chain.)

Pipeline Venting

When pipeline operators need to perform maintenance on sections of their lines, they must first reduce the pressure inside, and remove gas from, the pipeline in order to reduce the risk of explosion. This is often achieved by simply venting the gas in the relevant pipeline section into the atmosphere. However, there are several methods for reducing pipeline pressure that result in significantly lower methane emissions, discussed below.

In 2013, pipeline venting for routine maintenance was responsible for 125,000 metric tons of methane emissions, or 4.5 million metric tons of CO_2 equivalent.[117] While pipeline vents are a less significant source of emissions than many others discussed in this working paper, cost-effective emissions reduction opportunities are available today that make sense in most instances.

When a section of pipeline is taken offline for planned or emergency maintenance, the natural gas in that line can be "pumped down" with in-line compressors—essentially moving enough gas out of the pipeline section to reduce pressure to safe levels. This method has been demonstrated to achieve emissions reductions approximately 50 percent below what they would be through venting alone.[118] And portable compressors that maintenance teams can bring to the pipeline segment in question can move even more gas out of the line, reducing pressure further and achieving emissions reductions on the order of 90 percent.[119] Both of these measures have immediate to near-immediate payback periods.[120]

EMISSIONS REDUCTION OPPORTUNITIES DURING DISTRIBUTION

Transmission pipelines deliver natural gas to end-users (such as power plants) as well as local gas utilities, which are responsible for distributing the gas to residential and commercial consumers. The distribution network is made up of larger pipelines, called mains, and smaller service lines that branch off of mains to deliver gas to homes and businesses. Unlike most transmission pipelines, many distribution lines are old and leaky. Cast iron and bare steel—the primary materials used for decades in building natural gas distribution networks, especially in the first half of the last century—have been shown to leak considerable amounts of gas as they age.[121] Newer materials, including plastic and steel coated with materials to prevent corrosion, are being used by utilities across the country to replace these older pipelines and reduce the incidence of

Table 4 | **Key Recommendations for Transmission Stage Policies**

SOURCE OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES	PERCENTAGE OF METHANE EMISSIONS FROM NATURAL GAS SYSTEMS IN 2013[122]
Pipeline Venting	For planned maintenance, pipeline operators must use portable compressors—either alone or in conjunction with in-line compressors located at the compressor station—to reduce pipeline pressure to 90 percent below normal operating levels. For emergency repairs when there is not enough time to secure a portable compressor, maintenance teams should use in-line compressors to reduce pipeline pressure to 50 percent below normal operating levels (if doing so does not present a safety hazard).	3

gas leaks, which can be dangerous to people and property as well as harmful to the environment.

However, thousands of miles of cast iron and bare steel pipelines remain beneath city streets. With replacement costs on the order of half a million dollars per mile or more, pipeline replacement programs are expensive.[123] Because costs are so high, natural gas utilities prioritize fixing leaks and replacing old pipes that pose risks of explosions or other hazards. Many utilities do have programs in place to replace all cast iron and bare steel pipelines in their networks, but some of these programs will not achieve the complete elimination of cast iron pipes for decades.[124] Moreover, because measures to reduce distribution leaks do not usually pay for themselves through increased natural gas sales alone, unlike many of the practices outlined above, utilities typically recover the costs of pipeline replacement programs from their consumers, through rate increases or surcharges. Because state regulators in most instances need to approve any cost-recovery programs, it can be difficult to accelerate pipeline-replacement programs. However, because of the dominant role of state public utility commissions and other regulators in overseeing the natural gas distribution system, states can do much to reduce methane emissions from distribution networks.

Currently, most states require the classification of distribution leaks into one of three tiers: those that pose an imminent danger and require immediate attention (Tier 1), those that pose some risk and should be fixed within a reasonable amount of time (Tier 2), and those that do not pose much risk but should be monitored on a regular basis (Tier 3).[125] Large leaks that do not pose a risk to people or property do not require an immediate fix, even though they may be emitting significant quantities of methane. To reduce emissions, state regulators can create a fourth tier for such leaks—below Tier 1 but above Tier 2—requiring that these leaks be fixed as soon as practicable.

California has taken steps to put such a system into practice. Senate Bill 1371, approved in September 2014, charges the state's Public Utilities Commission with finding ways to require natural gas distribution utilities to locate and repair leaks.[126] S.B. 1371 targets large leaks that do not necessarily pose a health or safety risk, but would require "the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components...within a reasonable time after discovery."[127] California is positioning itself ahead of the curve in identifying and repairing leaky distribution infrastructure, and could serve as an example for other states to follow.

Table 5 | **Key Recommendations for Distribution Stage Policies**

SOURCES OF EMISSIONS	POLICY RECOMMENDATIONS AND BEST PRACTICES
Pipeline Replacement Programs	State regulators should allow for accelerated pipeline replacement programs, which would likely require higher prices for gas customers. Regulators should ensure that lower-income households are not adversely affected by any price increase.
Leak Reclassification	State legislators or regulators should work with natural gas utilities to modify the existing system of leak classification, which does not assign a high priority to repairing large leaks that do not pose a threat to people or property. Such leaks should be categorized as Tier 2, and should be repaired within a reasonable amount of time (for example, three months or less).
Leak Inspection	Utilities should be required to use vehicle-mounted emissions-detection equipment to survey their entire network at least twice per year.
Meter Replacement	Residential and commercial meters should be tested for accuracy at least once every seven years.[128] If flow accuracy is found to have fallen below 98 percent, the meter should be replaced.

To detect leaks, utilities perform regular inspections of gas mains and service lines, and rely on the public to notify them whenever they smell natural gas in their home or office. Performing regular inspections often entails using hand-held hydrocarbon sensors while following the path of the subterranean pipelines. However, new vehicle-mounted technology allows for quicker and more accurate inspections.[129] States should require the use of vehicle-mounted emissions detection equipment, and mandate more frequent surveys to ensure that leaks of all sizes are monitored and repaired as quickly as possible.

Lastly, states can contribute to progress in improving the accuracy of residential and commercial meters. Currently, natural gas distribution utilities are allowed to recover the cost of any gas that is "lost and unaccounted for." This category includes pipeline leaks, but it also accounts for differences in sensitivity between highly accurate meters at the end of the transmission pipeline and the less accurate meters at homes and businesses, which can slow down over time. Because it is nearly impossible to determine how much gas falls into the latter category, state regulators allow utilities to pass on to consumers the cost of lost and unaccounted for gas. However, more accurate residential and commercial meters could help reduce the amount of gas that is written off as "unaccounted for," and help companies identify with more precision how much gas is leaking throughout their system. To that end, states can require that companies replace older meters—which slow down as they age—with more accurate ones, though this is unlikely to be a cost-effective solution. As an interim measure, utilities can test the accuracy of a subset of meters, and apply that flow factor across the entire set of meters in their service area to better estimate the "unaccounted for" gas.[130]

CONCLUSION

States can lead the way on reining in methane emissions from natural gas development. Thirty-three states currently produce natural gas and, while Colorado is currently the only state with rules directly targeting methane emissions, others—including Wyoming, Pennsylvania, and Ohio—have taken steps to address other pollutants that will also have the effect of reducing methane emissions.[131] State rules have helped to shape federal emissions standards, and momentum is building as states learn from one another and companies share best practices.[132] Yet both states and the federal government are still playing catch-up, because the rapid increase in natural gas production in the United States over the past decade has far exceeded the efforts of states and the federal government to impose common-sense emissions standards that protect human health and the environment without unduly burdening industry.

Using the policy and technology solutions identified in this paper, states can continue to make progress on mitigating the climate and public health impacts of natural gas development. As we have discussed, opportunities exist at every stage of the natural gas life cycle, from preproduction through distribution. But proactive government policies are needed to ensure that emissions-reduction opportunities are capitalized upon, ensuring that the potential climate advantage of natural gas—its relatively low carbon content—is not undermined by unnecessary emissions of methane.

While state-level and national emissions standards for methane will be the most effective way to ensure deep reductions in methane emissions, investors, shareholders, and companies can also be an important part of the solution. Investors and shareholders can insist upon a commitment to using proven best practices, including those listed in this working paper. And companies can lay the groundwork for ambitious standards by demonstrating that reducing emissions and turning a profit do not have to be mutually exclusive.

Natural gas can play a part in helping the United States meet its near-term climate goals, but only if methane emissions are brought under control. The natural gas industry must also preserve its social license to operate, which depends on the goodwill of local residents who are impacted by drilling, by ensuring that operations do not pollute air or water, cause earthquakes, strain water supplies, or otherwise damage the local environment. The good news is that the technologies to address emissions from all sources along the supply chain are available, and are among the most cost-effective greenhouse gas emissions-reduction measures available. We know the types of policies that will encourage greater utilization of emissions-control technologies and best practices, and that can bring methane emissions below one percent of total production. Strong state standards can help lead the way.

ENDNOTES

1. Arkansas, for example, saw its natural gas production increase six-fold between 2005 and 2013, while Pennsylvania's production increased nearly twenty-fold over that period. For more information, see: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

2. Methane lasts between roughly nine and twelve years in the atmosphere, but during that short time it traps considerably more heat than an equivalent amount of carbon dioxide, which has a much longer lifespan in the atmosphere. In order to compare the relative impacts of different greenhouse gases, scientists devised the concept of global warming potential, which is a factor of how much heat is trapped in the atmosphere over a given time period by a particular gas, relative to carbon dioxide. Policymakers typically compare greenhouse gases over 20- and 100-year timeframes. The former gives greater weight to short-term damages, while the latter is more useful for longer-term planning (and has become the convention for most policymakers around the world). For methane from fossil sources, the global warming potentials for 20 and 100 years are 87 and 36, respectively. For more details, see: http://www.climatechange2013.org/images/report/WG1AR5_Ch08SM_FINAL.pdf.

3. http://www.eia.gov/dnav/ng/hist/n9050us2a.htm, http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

4. The "break-even" leakage rate at which natural gas provides immediate and permanent climate benefits when burned instead of coal is roughly 3.2 percent. For using natural gas instead of gasoline, it is 1.6 percent, and for substituting natural gas for diesel, 1 percent. For more information, see: http://www.pnas.org/content/early/2012/04/02/1202407109.full.pdf+html and http://www.wri.org/publication/clearing-air.

5. For more information, see: http://www.onefuture.us/.

6. For studies that find higher estimates of methane leakage, see Brandt, A.R. et al. 2014. "Methane Leaks from North American Natural Gas Systems." Science Magazine. Vol 343, February 2014). Accessible at: <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>; Oliver Schneising et al. 2014. "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations" Earth's Future. Accessible at: <http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full>; Gabrielle Petron et al. 2014. "A New Look at Methane and Nonmethane Hydrocarbon Emissions From Oil and Natural Gas Operations in the Colorado Denver-Julesburg Basin." Journal of Geophysical Research: Atmospheres. Available at: http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/pdf; and Scott Miller et al. 2013. "Anthropogenic Emissions of Methane in the United States," Proceedings of the National Academy of Sciences of the United States of America. Accessible at: <http://www.pnas.org/content/early/2013/11/20/1314392110.full.pdf+html. We should note as well that other studies have found leakage rates and emissions factors comparable to or less than the estimates in the EPA Greenhouse Gas Inventory. These include several bottom-up studies undertaken by EDF and universities. For those studies, see: http://www.edf.org/climate/methane-studies. For WRI's response to EDF and the University of Texas' production study, see: http://www.wri.org/blog/2013/09/new-study-sheds-light-methane-leakage-natural-gas.

7. For a discussion of these market barriers, see Chapter 4 of: http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states.

8. See http://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201410&RIN=1004-AE14.

9. See http://www.epa.gov/airquality/oilandgas/pdfs/20150114fs.pdf.

10. While EPA is currently considering implementing methane emissions standards for some of the sources listed here, many states are taking action. See Box 1 for more information on potential EPA standards.

11. These emissions sources and recommendations are covered in more detail in the body of this working paper.

12. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf

13. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.

14. Analysis by the Clean Air Task Force found that semi-annual leak surveys at natural gas plants entailed negative net abatement costs, while quarterly surveys entailed small positive costs. See: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf. However, for some facilities, CATF recommends quarterly or monthly surveys. See: http://www.catf.us/resources/publications/files/WasteNot_Appendix.pdf. Frequency of leak surveys should also take into account the existence of regular maintenance practices that can help to identify and repair leaking equipment.

15. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted six scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions from nearly three million passenger vehicles. For this reason, this paper recommends the replacement of high-bleed pneumatic devices with no-bleed equivalents whenever feasible.

16. Wells without plunger lifts average 2.9 metric tons of methane emissions per year. (See: http://www.epa.gov/airquality/oilandgas/2014papers/attachmenti.pdf). Plunger lifts can eliminate up to 99 percent of methane emissions from liquids unloading when used properly and venting is minimized or eliminated.

17. For some small leaks, it is possible that emissions (and economic losses) from the blowdown associated with shutting down the equipment may be greater than emissions (and economic losses) from the leak itself. However, analysis from the Clean Air Task Force has found that "…[t]he evaluation of available survey data shows that most leaks, once identified, are economic to repair with a payback period less than one year. As a result, once the survey has been performed, it is economic to repair almost all the leaks." Source: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

18. Includes the following emissions categories: non-associated gas wells, gas wells with hydraulic fracturing, heaters, separators, dehydrators, and meters/piping from the production stage; processing plants; compressor stations (transmission) stations, M&R (Trans. Co. Interconnect), M&R (Farm Taps + Direct Sales), Compressor Stations (Storage) Stations, Wells (Storage) from the transmission stage; and Meters/Regulator (City Gates) M&R>300, M&R 100-300, Reg >300, Reg 100-300 from the distribution stage.

19. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

20. ICF International. 2014. "Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries." March 2014. Available at: http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

21. Massachusetts has such a program in place. For more information, see: http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/gas-meter-testing-and-replacement.html.

22. For more information on state-level natural gas production, see: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

23. http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.

24. ICF International, 2014.

25. Emissions measurement technology is still too expensive to require constant emissions monitoring from the millions of potential sources.

26. Because EPA does not report an average nationwide leakage rate, WRI calculated a figure of 1.2 percent using methane emissions data from the 2015 GHG Inventory, and natural gas production data from EIA. To convert volumes of methane to volumes of natural gas, we assumed natural gas to have an average methane content of 83 percent in the production stage, 87 percent during processing, and 94 percent during transmission, storage, and distribution. See U.S. Environmental Protection Agency (EPA). 2015. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2013. April 2015. Accessible at: http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html and U.S. Energy Information Administration, "Natural Gas Gross Withdrawals and Production." Accessible at: <http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm> For studies that find higher estimates of methane leakage, see Brandt, A.R. et al. 2014. "Methane Leaks from North American Natural Gas Systems." Science Magazine. Vol 343, February 2014. Accessible at: <http://www.novim.org/images/pdf/ScienceMethane.02.14.14.pdf>; Schneising, O. et al. 2014. "Remote sensing of fugitive methane emissions from oil and gas production in North American tight geologic formations." Earth's Future. Accessible at: <http://onlinelibrary.wiley.com/doi/10.1002/2014EF000265/full>; and Miller, S. et al. 2013. "Anthropogenic Emissions of Methane in the United States." Accessible at: <http://www.pnas.org/content/early/2013/11/20/1314392110.full.pdf+html>. We should note as well that other studies have found leakage rates and emissions factors comparable to or less than the estimates in the EPA Greenhouse Gas Inventory. These include several bottom-up studies undertaken by EDF and universities. For those studies, see http://www.edf.org/climate/methane-studies. For WRI's response to EDF and the University of Texas' production study, see: http://www.wri.org/blog/2013/09/new-study-sheds-light-methane-leakage-natural-gas.

27. See, for example: http://pubs.usgs.gov/of/2003/of03-409/of03-409.pdf.

28. In 2012, EPA finalized new air quality standards targeting VOCs and HAPs from sources located primarily at the well site. For more information, see http://www.epa.gov/airquality/oilandgas/actions.html. In January 2015, EPA announced its intention to propose new rulemakings that, in part, build on these VOC and HAP standards. For more information, see: http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

29. https://www.naesb.org/pdf2/wgq_bps100605w2.pdf.

30. For more information on how emissions reductions and economic benefits can go hand in hand, including a discussion of market barriers inhibiting wider deployment of emissions control technologies in the natural gas industry, see: http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states.

31. Self-reported emissions data from oil and gas companies suggest that even large, vertically integrated companies may not be utilizing best practices in their operations, despite being in the best position to do so. These companies can increase revenues by taking advantage of the technologies and practices described in this working paper to become more efficient and reduce their methane emissions. An October 2014 study by ClimateWire, which looked at emissions data reported to EPA under the Greenhouse Gas Reporting Program, found that "[t]he worst offenders have little in common when it comes to the scale or nature of operations. The implication is that companies do not all tackle the methane problem with equal seriousness, especially in the absence of comprehensive regulation." For more information, see: http://www.eenews.net/climatewire/2014/10/06/stories/1060006912 and http://www.epa.gov/ghgreporting/.

32. Source: ICF International, 2014. Moreover, a November 2013 study found that an accelerated pipeline replacement program in just five states could generate nearly 50,000 jobs. For more details, see: http://www.e3network.org/papers/The-Keystone-Pipeline-Debate.pdf. Accelerated pipeline replacement programs are discussed in more detail in the Distribution section of this working paper.

33. According to a September 2014 study from Stratus Consulting, methane emissions from oil and gas development on public lands increased by 135 percent between 2008 and 2013, to 175,000 metric tons of methane. For more information, see: http://wilderness.org/sites/default/files/Stratus-Report.pdf and http://cdn.americanprogress.org/wp-content/uploads/2014/10/ReducingMethane.pdf.

34. There are many market barriers inhibiting greater uptake of cost-effective measures by the natural gas industry. These include principal-agent problems, whereby incentives for investing in emissions-control technologies are not well aligned; imperfect information on the scope of the emissions problem; and opportunity costs. For more details, see Chapter 4 of Bianco et al. October 2014. “Seeing is Believing: Creating a New Climate Economy in the United States.” Washington, D.C.: World Resources Institute. Available at: http://www.wri.org/sites/default/files/seeingisbelieving_working_paper.pdf.

35. The “break-even” leakage rate at which natural gas becomes cleaner than coal over all time horizons is roughly 3.2 percent. For gasoline, it is 1.6 percent, and for diesel, 1 percent. For more information, see: http://www.pnas.org/content/early/2012/04/02/1202407109.full.pdf+html and http://www.wri.org/publication/clearing-air.

36. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentl.pdf.

37. http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

38. Section 111 grants EPA authority to set standards of performance for harmful air emissions, including greenhouse gases, from new and existing stationary sources. Once EPA sets a minimum standard of performance, states are required to implement and enforce compliance with that standard. This is the same section of the Clean Air Act that EPA is using to set carbon dioxide emissions standards for new and existing power plants. For the full text of Section 111, see: http://www.law.cornell.edu/uscode/text/42/7411.

39. http://www.epa.gov/airquality/oilandgas/whitepapers.html.

40. For more details on the administration’s January 2015 announcement that it will propose methane standards for new and modified natural gas infrastructure, see: http://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

41. This is especially true when the health benefits of avoided emissions of VOCs and other hazardous air pollutants are included. Note that it might be necessary to restructure service provider contracts to ensure that the economic benefits of reducing leaks of natural gas accrue to the company investing in the equipment or personnel.

42. There are examples of this phenomenon in the area of regulating methane emissions, as well. EPA’s 2012 New Source Performance Standard requiring the use of reduced emissions completions at the wellhead was modeled on a similar, successful approach used in Colorado and Wyoming. See: http://www.epa.gov/airquality/oilandgas/pdfs/20110728factsheet.pdf and http://www.epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=bc4a4812-ca46-4d22-b593-e3929c2c64a6.

43. Ibid.

44. For President Obama’s methane strategy, see: http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf. For more information on Section 111 of the Clean Air Act, see http://www.law.cornell.edu/uscode/text/42/7411 and http://web.law.columbia.edu/climate-change/clean-air-act.

45. Completions of oil wells with associated natural gas are not covered by the 2012 NSPS, despite being a major source of natural gas production and a significant source of VOC and methane emissions. EPA should close this loophole to ensure that all natural gas production is subject to the same emission reduction requirements.

46. For a sample permit application describing green completion requirements in Wyoming, see: http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Application%20Forms/AQD-OG11_Green%20Completion%20Application.pdf.

47. http://www.epa.gov/airquality/oilandgas/pdfs/20120417fs.pdf.

48. For more details on the technologies listed in this paper, as well as some of the methods currently available to reduce emissions from these sources, see: http://www.epa.gov/gasstar/tools/recommended.html.

49. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

50. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

51. EPA’s annual Greenhouse Gas Inventory is still considered the most definitive source of emissions estimates, though many recent studies contend that the Agency significantly underestimates the amount of methane emitted by the natural gas industry. Part of the reason for the discrepancy is the way in which EPA calculates its estimates. Because measuring emissions from the millions of sources in the natural gas supply chain is infeasible, EPA multiplies the number of processes or pieces of equipment (activity data) by an average emissions factor for that process or equipment. Both of these inputs are estimates, but there is more certainty around the activity data than the emissions factors. Emissions factors are averages, and may underestimate the impact of “superemitters,” that is, a small fraction of sources responsible for a large fraction of emissions. Moreover, emissions factors can vary widely across different geographies, and across companies. To the extent possible, states should supplement EPA Inventory data with direct measurements to provide a more robust picture of methane emissions from various sources in each state. For examples of recent studies suggesting higher amounts of methane emissions, see: http://www.pnas.org/content/110/50/20018.full and http://onlinelibrary.wiley.com/doi/10.1002/2013JD021272/abstract.

52. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Includes estimated reductions due to voluntary measures.

53. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf and http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

54. For reference, the average Henry Hub daily spot price over 2014 was approximately $4.37 per Mcf, though the average price through the first five months of 2015 was just $2.83 per Mcf. See: http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm.

55. http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.

56. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Assumes voluntary measures result in emissions reductions of 45 percent, the average for emissions sources in the production sector, according to the EPA Inventory.

57. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf. As of this writing, there are additional studies underway that aim to improve measurement estimates of emissions from pneumatic devices and understand the sources of variability within those estimates.

58. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted 6 scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions from nearly three million passenger vehicles. And Allen et al. (2013) found that even low-bleed devices often emit more than six scf per hour (see: http://www.pnas.org/content/110/44/17768.full). For these reasons, this paper recommends the replacement of high-bleed, low-bleed, and intermittent pneumatic devices with no-bleed equivalents whenever feasible, and including all low-bleed pneumatics in LDAR programs.

59. http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf, and http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

60. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

61. http://www.epa.gov/gasstar/documents/ll_instrument_air.pdf, http://www.nrdc.org/energy/files/Leaking-Profits-Report.pdf.

62. 2 Colo. Code Regs. § 404-1:805(b)(2)(E); 5 Colo. Code Regs. § 1001-9 XVIII.C.1.

63. Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, Section XVIII. Available at: https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=5670. Other rules in Colorado, adopted in February 2014, address methane emissions from additional sources.

64. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

65. http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf, http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html, http://pubs.acs.org/doi/abs/10.1021/es504016r.

66. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

67. http://www.epa.gov/ghgreporting/ghgdata/reportingdatasets.html.

68. Until recently, liquids unloadings were the most significant source of methane emissions from natural gas development in EPA's annual greenhouse gas inventory. However, in its 2013 Greenhouse Gas Inventory, in response to a survey from the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA), EPA reduced the emission factor used to estimate emissions from liquids unloading by over 90 percent. See: http://insideepa.com/201302262425851/EPA-Daily-News/Daily-News/citing-industry-data-epa-cuts-ghg-estimates-for-natural-gas-sector/menu-id-1046.html and http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf.

69. For some of these options, see: http://www.epa.gov/gasstar/documents/ll_options.pdf.

70. There is debate surrounding the effectiveness of plunger lifts as a low-emissions alternative to well blowdowns. A 2012 industry survey found that wells using plunger lifts for liquids unloading were responsible for more emissions than those that did not use plunger lifts. However, this could be due to particularities in the geology at the wells that did use plunger lifts, or to ineffective use of the equipment by untrained workers. See: http://www.api.org/~/media/Files/News/2012/12-October/API-ANGA-Survey-Report.pdf and http://www.epa.gov/airquality/oilandgas/2014papers/attachmenth.pdf.

71. http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.

72. http://www.epa.gov/airquality/oilandgas/2014papers/20140415liquids.pdf.

73. Ibid.

74. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf,

75. http://www.epa.gov/airquality/oilandgas/pdfs/20120418tsd.pdf.

76. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

77. http://www.epa.gov/airquality/oilandgas/2014papers/attachmento.pdf, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_BB_EDF.xlsx, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_CC_EDF.xlsx, http://www.epa.gov/airquality/oilandgas/2014papers/attachmentk.pdf.

78. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentl.pdf.

79. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

80. See, for example: http://www.epa.gov/airquality/oilandgas/2014papers/attachmento.pdf and http://www.epa.gov/airquality/oilandgas/2014papers/attachmentp.pdf.

81. http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

82. http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.

83. http://arpa-e.energy.gov/?q=arpa-e-news-item/arpa-e-announces-60-million-disruptive-technologies-cut-emissions-boost-energy, http://www.edf.org/energy/natural-gas-policy/methane-detectors-challenge.

84. Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7, Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions, Section XVII F. Available at: https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.

85. Noble Energy, Encana, and Anadarko Petroleum worked with Colorado officials to help craft the rules, and publicly support the state's efforts. See: http://www.bizjournals.com/denver/blog/earth_to_power/2014/02/noble-energy-anadarko-petroleum-and.html?page=all.

86. Ibid.

87. There are trade-offs involved when deciding how quickly leaks must be repaired after they are first detected. For example, a shorter lead time likely means more employees need to be trained in how to repair leaks. Nevertheless, because learning how to fix most leaks does not require extensive training, and LDAR is generally one of the most cost-effective measures for reducing emissions, we believe that five days should be the upper bound for the deadline before which detected leaks must be repaired, with exceptions for extenuating circumstances such as those identified by Colorado.

88. Personal communication with William C. Allison V, Director, Air Pollution Control Division, Colorado Department of Public Health and Environment, 9/23/14. Wyoming requires the use of infrared cameras at processing plants and new wells.

89. Pennsylvania requires the use of LDAR at new wells within 60 days of entering into production, and annually thereafter. At compressor stations and processing plants, Pennsylvania requires an initial LDAR survey, and quarterly surveys thereafter. For more information, see: http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf and http://files.dep.state.pa.us/Air/AirQuality/AQPortalFiles/Permits/gp/MethaneRegulations.pdf.

90. Ohio's new rules require companies to develop plans for regular LDAR, to be submitted along with applications for permits-to-install. Covered equipment includes pumps, compressors, pressure relief devices, valves, flanges, and storage containers. Monitoring must occur quarterly for the first year of operation, and repairs must be made within five days of discovery. After the first year, if less than two percent of equipment is found to be leaking, operators can reduce their monitoring to semi-annually and then annually. For more information, see: http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf. For information on permit applications, see http://www.epa.ohio.gov/dapc/genpermit/genpermits.aspx.

91. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

92. http://www.epa.gov/airquality/oilandgas/pdfs/20110728tsd.pdf.

93. Analysis by the Clean Air Task Force found that semi-annual leak surveys at natural gas plants entailed negative net abatement costs, while quarterly surveys entailed small positive costs. See: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf. However, for some facilities, CATF recommends quarterly or monthly surveys. See: http://www.catf.us/resources/publications/files/WasteNot_Appendix.pdf. Frequency of leak surveys should also take into account the existence of regular maintenance practices that can help to identify and repair leaking equipment.

94. Six standard cubic feet per hour is roughly 52 Mcf per year. At $4.50 per Mcf, this represents over $235 worth of wasted gas per year from a pneumatic device that could be considered "low-bleed." If all 459,000 pneumatic devices in the production sector (as estimated by the 2015 EPA Inventory) emitted six scf per hour, over 24 billion cubic feet of gas worth nearly $110 million would be vented to the atmosphere each year. At an average methane composition of 80 percent, this is equivalent to 367,000 metric tons of methane, or over 13 million tons of CO_2 equivalent—equivalent to the emissions of nearly three million passenger vehicles. For this reason, this paper recommends the replacement of high-bleed and low-bleed pneumatic devices with no-bleed equivalents whenever feasible.

95. Wells without plunger lifts average 2.9 metric tons of methane emissions per year. (See: http://www.epa.gov/airquality/oilandgas/2014papers/attachmenti.pdf). Plunger lifts can eliminate up to 99 percent of methane emissions from liquids unloading when used properly and venting is minimized or eliminated.

96. For some small leaks, it is possible that emissions (and economic losses) from the blowdown associated with shutting down the equipment may be greater than emissions (and economic losses) from the leak itself. However, analysis from the Clean Air Task Force has found that "…[t]he evaluation of available survey data shows that most leaks, once identified, are economic to repair with a payback period less than one year. As a result, once the survey has been performed, it is economic to repair almost all the leaks." Source: http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf.

97. Includes the following emissions categories: non-associated gas wells, gas wells with hydraulic fracturing, heaters, separators, dehydrators, and meters/piping from the production stage; processing plants; compressor stations (transmission) stations, M&R (Trans. Co. Interconnect), M&R (Farm Taps + Direct Sales), Compressor Stations (Storage) Stations, Wells (Storage) from the transmission stage; and Meters/Regulator (City Gates) M&R>300, M&R 100-300, Reg>300, Reg 100-300 from the distribution stage.

98. For more information on the composition of natural gas, see: Burruss, R.C. and R.T. Ryder, "Composition of Crude Oil and Natural Gas Produced from 14 Wells in the Lower Silurian 'Clinton' Sandstone and Medina Group, Northeastern Ohio and Northwestern Pennsylvania." March 22, 2004. Washington, D.C.: U.S. Department of Interior, U.S. Geological Survey. Available at: http://pubs.usgs.gov/of/2003/of03-409/of03-409.pdf; and North American Energy Standards Board, "Natural Gas Specs Sheet." June 2004. Available at: https://www.naesb.org//pdf2/wgq_bps100605w2.pdf.

99. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

100. Ibid.

101. http://www.epa.gov/gasstar/documents/ll_wetseals.pdf. Up-front costs for dry seals might be greater than those for wet seals, however.

102. http://www.gpo.gov/fdsys/pkg/FR-2012-08-16/pdf/2012-16806.pdf.

103. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

104. http://www.epa.gov/airquality/oilandgas/2014papers/attachmentr.pdf, http://www.epa.gov/airquality/oilandgas/2014papers/Attachment_AA_EDF.xlsx.

105. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

106. http://www.epa.gov/gasstar/documents/ll_wetseals.pdf.

107. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf, http://www.epa.gov/gasstar/documents/CaptureMethanefromCentrifugalCompressionSealOilDegassing.pdf.

108. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

109. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf. Note: A similar amount of methane was leaked or vented from engines in the production and transmission stages as well.

110. http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

111. http://www.epa.gov/ttnchie1/ap42/ch03/final/c03s02.pdf.

112. http://epa.gov/gasstar/documents/replacegas.pdf.

113. http://epa.gov/gasstar/documents/installelectricstarters.pdf.

114. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

115. http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf.

116. ICF International. 2014. “Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries.” Available at: http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

117. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

118. http://www.epa.gov/gasstar/documents/ll_pipeline.pdf.

119. Ibid.

120. Ibid, http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

121. See, for example: http://sites.biology.duke.edu/jackson/ep2013.pdf and http://sites.biology.duke.edu/jackson/est2014.pdf.

122. http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf.

123. See, for example: http://www.puco.ohio.gov/puco/index.cfm/consumer-information/consumer-topics/natural-gas-pipeline-safety-in-ohio/#sthash.sLdAB0Xj.dpbs. For this reason, many emissions abatement measures in the distribution segment are much less cost-effective than measures in other segments of the natural gas value chain. The exception is equipment leaks at above-ground meters and regulation stations, which should be subject to the same LDAR regimes as processing plants, compressor stations, and other upstream infrastructure discussed above. For more information, see: https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

124. For example, Connecticut, New York, and Pennsylvania—three of the states with the most miles of cast iron pipelines—have set goals for complete replacement with plastic or coated steel by 2080, 2090, and 2111, respectively. For more information, see: https://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/.

125. See, for example: http://www.wbur.org/2014/07/07/patrick-springfield-gas-leaks.

126. For full text of bill, see: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1371.

127. Ibid.

128. Massachusetts has such a program in place. For more information, see: http://www.mass.gov/eea/energy-utilities-clean-tech/natural-gas-utility/gas-meter-testing-and-replacement.html.

129. One such company, Picarro Inc., has invented vehicle-mounted leak survey technology that has been used by researchers in Boston and Washington, D.C. to identify the location and magnitude of leaks from distribution pipelines—many of which were unknown to the local utility. For more information on the Picarro Surveyor, see: http://www.picarrosurveyor.com/. For studies, see http://sites.biology.duke.edu/jackson/ep2013.pdf and http://sites.biology.duke.edu/jackson/est2014.pdf.

130. Personal communication with Greg Davies, December 7, 2014.

131. Source: http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm. Note: other states have policies in place that will reduce methane emissions, but only Colorado has rules that address methane directly.

132. See, for example: https://www.sustainableshale.org/.

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ABOUT WRI

World Resources Institute is a global research organization that turns big ideas into action at the nexus of environment, economic opportunity and human well-being.

Our Challenge
Natural resources are at the foundation of economic opportunity and human well-being. But today, we are depleting Earth's resources at rates that are not sustainable, endangering economies and people's lives. People depend on clean water, fertile land, healthy forests, and a stable climate. Livable cities and clean energy are essential for a sustainable planet. We must address these urgent, global challenges this decade.

Our Vision
We envision an equitable and prosperous planet driven by the wise management of natural resources. We aspire to create a world where the actions of government, business, and communities combine to eliminate poverty and sustain the natural environment for all people.

Our Approach
COUNT IT
We start with data. We conduct independent research and draw on the latest technology to develop new insights and recommendations. Our rigorous analysis identifies risks, unveils opportunities, and informs smart strategies. We focus our efforts on influential and emerging economies where the future of sustainability will be determined.

CHANGE IT
We use our research to influence government policies, business strategies, and civil society action. We test projects with communities, companies, and government agencies to build a strong evidence base. Then, we work with partners to deliver change on the ground that alleviates poverty and strengthens society. We hold ourselves accountable to ensure our outcomes will be bold and enduring.

SCALE IT
We don't think small. Once tested, we work with partners to adopt and expand our efforts regionally and globally. We engage with decision-makers to carry out our ideas and elevate our impact. We measure success through government and business actions that improve people's lives and sustain a healthy environment.