Comparing Policies to Reduce Methane Emissions in the Natural Gas Sector

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Abstract

Methane emissions from the natural gas sector threaten to erode the climatic benefit that gas holds over coal. Yet the majority of existing sources of methane emissions in the natural gas sector remain unregulated. This is due in part to concerns that policies to mitigate these emissions would entail overseeing a large number of sources and impose significant administrative and compliance costs. Unfortunately, the typical market-based approaches that might ameloriate these concerns, such as a pollution tax, are not practical at the moment because there are no accurate and publicly available firm-level inventories of methane emissions; however, monitoring technologies are improving quickly, meaning that such inventories may be available in the foreseeable future. Focusing on the United States, we describe a suite of prototypical policies to reduce methane emissions from the natural gas sector, including technology standards, performance standards on firms, performance standards with averaging, tradable performance standards, several types of leak detection and repair programs, and a pollution tax with default and updatable leakage rates. We then analyze the extent to which each of these policies provides appropriate incentives for abatement, given the unique attributes of methane emissions from the natural gas sector. Finally, we compare these policies in terms of administrative costs, economic efficiency, and environmental effectiveness. We find, among other things, that a pollution tax with assumed and updatable default leakage rates performs particularly well in terms of economic efficiency and environmental effectiveness.

Key Words: methane leaks, natural gas, climate change

JEL Codes: Q48, Q54, Q58

Contents

1. Introduction

The natural gas sector's emissions of methane, a potent greenhouse gas, threaten to erode the climatic benefit gas holds over coal and its status as a bridge fuel to a future without fossil fuels. In the United States, some states, such as Colorado, are taking on this issue through regulation. Under the Obama administration, the federal government recently regulated methane from new sources and from drilling operations on federal lands. But both regulations are in jeapordy under the Trump administration. Overall, most existing sources of methane in the natural gas sector remain unregulated.

The concept of natural gas as a bridge fuel that transitions the United States into a low-carbon future has received high-level political support (e.g., Podesta and Wirth 2009; Obama 2014) because natural gas emits about half as much carbon dioxide as coal when combusted (EIA 2015a). Before combustion occurs, however, the US natural gas sector emits significant amounts of gas by intentionally venting gas during operational procedures or unintentionally releasing fugitive gas through leaks in wells and equipment (ICF 2014).[1]

These emissions have a disproportionately large effect on the climate because the main ingredient of natural gas, methane, is a highly potent greenhouse gas—with a global warming potential (GWP) about 86 times greater than that of carbon dioxide (CO_2) over a 20-year time frame and 34 times greater over a 100-year time frame (Myhre et al. 2014). Mitigating methane emissions is therefore an important strategy to diminish climate effects in the shorter term and complement the longer-term mitigation of carbon dioxide emissions (Shoemaker et al. 2013).

If large enough, methane emissions from the natural gas sector can erode some of the climatic benefit that would otherwise be associated with switching to gas from other fossil fuels. Combusting natural gas instead of coal, gasoline, or diesel provides immediate climatic benefits (i.e., an immediate net decrease in radiative forcing) only if less than 2.7, 1.4, or 0.8 percent of produced natural gas, respectively, is emitted before it is used (Alvarez et al. 2012; Hamburg 2013).[2] Based on US government sources, we calculate that methane emissions from the natural gas industry as a fraction of US methane production, referred to as the leakage rate, ranged from approximately 3.2 to 1.8 percent from 1990 through 2014 (Figure 1). These estimates are based on natural gas production from the Energy Information Administration (EIA 2016) and methane emissions from the natural gas sector provided by the US

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[1] Although significant methane emissions also originate from the oil sector (68.1 million metric tons of carbon dioxide equivalent [MMTCO$_2$e] in 2014) and coal sector (67.6 MMTCO$_2$e in 2014), we mostly limit our focus to the natural gas sector because it is responsible for the majority of methane emissions, at 176.1 MMTCO$_2$e, according to EPA's Greenhouse Gas Inventory (2016), assuming a global warming potential (GWP) for the CO$_2$e conversion of 25. For further perspective, total methane emissions are 731 MMTCO$_2$e, with enteric and landfill emissions accounting for 302 MMTCO$_2$e (EPA 2016). The oil sector would likely be part of any regulatory approach to reduce methane emissions, since many wells produce both oil and gas.

[2] Alvarez et al. (2012) have introduced the term "technology warming potentials" (TWPs) as an improvement to global warming potentials. TWPs plot the relative radiative forcing of alternative technologies as a function of time, allowing researchers to, for example, identify whether switching to a particular technology would provide an immediate climatic benefit (i.e., reduction in net radiative forcing).

Environmental Protection Agency (EPA) through its annual Greenhouse Gas Inventory (GHGI; EPA 2016). Figure 1 suggests that leakage rates have declined over time and implies that substituting natural gas for coal would indeed provide immediate climatic benefits.

Yet a growing number of studies find that EPA tends to significantly underestimate the volume of methane emitted from natural gas subsectors at national, regional, and local scales (e.g., Brandt et al. 2014; see Appendix Table A1 for a review of this literature). Although the precise extent to which EPA might underestimate methane emissions from the entire natural gas sector at the national level remains unclear, numerous studies suggest that particular segments of the sector exhibit particularly high leakage rates (e.g., Karion et al. 2013; Peischl et al. 2013; McKain et al. 2015; Lan et al. 2015; see Appendix Table A2 for a review of this literature), raising the question whether a strategy of replacing coal with natural gas would produce immediate climatic benefits.

Methane's potent GWP and the prospect that its emissions may erode the climatic benefits of switching to natural gas from other fossil fuels have inspired action from industry and regulators across the United States. For most of the past two decades, this action has taken the form of voluntary approaches spearheaded by EPA and more recently by industry groups, but within the past four years, it has strongly pivoted toward regulation at the federal and state levels.

EPA created the first voluntary approach, the Natural Gas STAR (NG STAR) program, in 1993. NG STAR encourages oil and natural gas companies to voluntarily adopt technologies that reduce methane emissions. An industry coalition, Our Nation's Energy Future Coalition (ONE Future), started its own voluntary approach in 2014, with a goal of achieving an average rate of methane emissions across the entire natural gas value chain that is 1 percent or less of total natural gas production. A revamped version of NG STAR, the Methane Challenge Program, launched in 2016, encourages oil and natural gas companies to voluntarily commit to employ best management practices at the company firm level or achieve particular methane emissions rates at the sector level (EPA 2015a) (see Box 1 for further details).

FIGURE 1. LEAKAGE RATES (%) FROM NATURAL GAS SYSTEMS IN UNITED STATES, 1990–2014
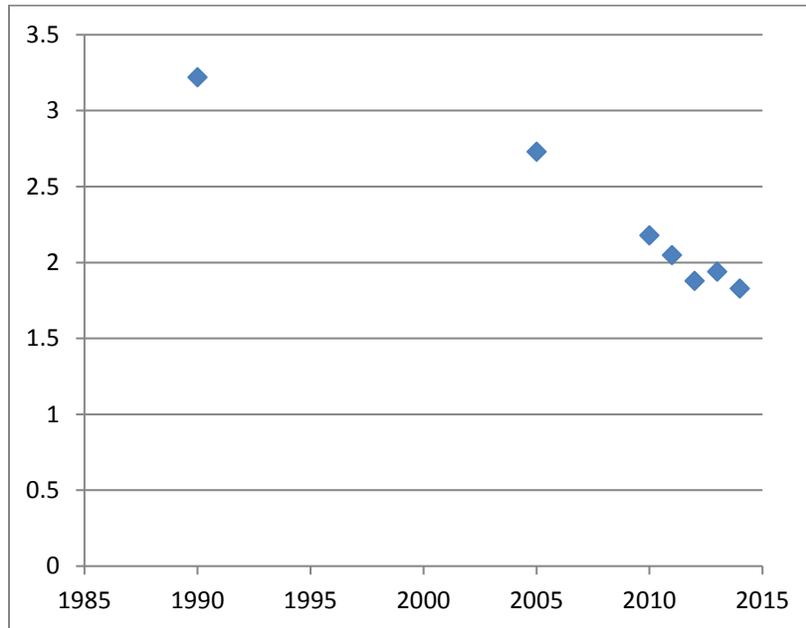
Source: Authors' calculations.
Note: Leakage rate is a ratio in which the numerator includes methane emissions from natural gas systems (Table 3-48 of EPA 2016) and the denominator includes methane production (gross withdrawals from natural gas and shale gas wells, from EIA 2016, multiplied by an assumed 0.83 methane content). Some of the methane emissions from natural gas systems are composed of natural gas that originates from oil or coalbed wells, which together were responsible for about 23 percent of natural gas withdrawals in 2014, meaning that our estimated leakage rates may be biased upward. In contrast, estimates of leakage rates from the natural gas sector that include natural gas withdrawals from the oil and coal sector are biased downward if they do not also include methane emissions from the oil and coal sector in the numerator. We do not consider how imports and exports affect these numbers.

Several state governments—among them, those of California, Colorado, and Pennsylvania—turned to a regulatory approach in the early 2010s. Among these states, Colorado was first to act, in 2014 issuing rules to address methane emissions from the oil and gas sector, and these rules currently impose several requirements on upstream subsectors. One rule, a technology standard, requires natural gas compressor stations to replace rod packing every 26,000 hours of operation or every 36 months. Another, a leak detection and repair program, requires operators to monitor components of natural gas production facilities and compressor stations for leaks and repair them. According to the Colorado Department of Public Health and Environment,[3] which has responsibility for this program, the number of reported leaks has fallen 75 percent since the rule went into effect.[4]

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[3] See
https://www.eenews.net/climatewire/2017/01/30/stories/1060049171.

[4] Martha Rudolph, director of Environmental Programs, personal communication, October 2016.

BOX 1. EPA'S AND ONE FUTURE'S VOLUNTARY APPROACHES

EPA oversees the Natural Gas STAR (NG STAR) program, which started in 1993 and encourages oil and natural gas companies to voluntarily adopt technologies that reduce methane emissions. About 100 companies across the four natural gas subsectors currently participate in the NG STAR program (EPA 2015c).

To participate in the NG STAR program, a company must complete four steps. First, it must sign a memorandum of understanding with EPA. Second, it must develop an implementation plan that identifies specific methane reduction technologies—selected by the company or taken from a list provided by—that the company deems cost-effective. Third, it must execute the implementation plan. Finally, the company must submit an annual progress report to EPA. In return, the company receives technical guidance and public recognition from EPA, as well as a public record of estimated reductions.

According to EPA, the NG STAR program has avoided more than 526 MMTCO$_2$e of methane emissions in the United States since 1993. More than two-thirds of these reductions originated from the production sector, primarily through green completions, installation of plunger lifts and vapor recovery units (now required by law for new sources), and identification and replacement of high-bleed pneumatic devices.

In its recent rulemaking for the oil and gas sector, EPA proposed an upgrade to the NG STAR program called the NG STAR Methane Challenge Program, which allows companies to choose between two options for adopting and implementing an emissions reduction commitment: a best management practices (BMP) commitment and a ONE Future emissions intensity commitment. The first option commits a company to implementation of certain BMPs specified by EPA at one or more emissions sources. The ONE Future option is a commitment to achieve a particular subsector-specific methane emissions rate on an aggregate basis for all sources the company owns within that subsector (EPA 2015c). This option builds on a preexisting industry effort called ONE Future, a coalition of companies created by Southwestern Energy Company from across the natural gas value chain that endorses a set of sector-specific intensity-based performance standards for methane emissions in each natural gas subsector. The goal of ONE Future is to achieve a methane leakage rate of less than or equal to 1 percent of production across the natural gas value chain. Importantly, the ONE Future option does not include trading of pollution rights across the subsectors or companies; instead, each voluntarily participating company pledges to meet the emissions intensity standard in its subsector (ONE Future 2015).

We do not explicitly consider stylized voluntary approaches in this paper. Instead, we observe that the BMP commitment essentially encourages companies to adopt technology standards voluntarily, and that the ONE Future commitment does the same for performance standards with averaging within but not among firms.

The federal government entered the regulatory arena in 2015, when the Obama administration announced an overarching goal of reducing methane emissions from the oil and gas sector by 40–45 percent from 2012 levels by 2025 (White House 2015) and promulgated regulations under the CAA to make progress toward this goal. Most notably, in 2015, EPA proposed New Source Performance Standards (NSPS) under Section 111(b) of the CAA, which would require certain new and modified emissions sources to comply with performance and technology standards and to conduct leak, detection, and repair (LDAR) programs (Danish et al. 2015; EPA 2015b). EPA finalized this Section 111(b) proposal in May 2016 (Danish et al. 2016). This regulation has been delayed by the Trump administration, as noted above. In addition, EPA issued two information collection requests in 2016 to receive input from industry that would assist in drafting regulations on existing sources and solicit feedback on emerging technologies to measure and monitor methane emissions from the oil and gas sector. However, the Trump administration halted this information collection process in 2017. As noted above, BLM issued a regulation in 2016 to limit methane emissions from oil and gas operations on federal land. The Trump administration has also delayed implementation of this rule

This paper discusses several prototypical policies, some of which are approaches that have already been taken—voluntary approaches, performance standards, technology-based standards, and certain leak detection and repair (LDAR) programs—as well as novel approaches including more advanced LDAR programs and two types of market-based policies that have yet to fully enter the discussion: a tradable performance standard and a tax with assumed default leakage rates. We compare the potential strengths and weaknesses of these policies

given the unique aspects of methane emissions from the natural gas sector. This comparison is initial and idiosyncratic. We aim to prompt deeper research and discussion on how to regulate methane emissions from the natural gas sector, rather than provide conclusive evidence for a preferred policy approach.

The rest of this report is organized as follows. We identify "stylized" facts about methane emissions from the US natural gas sector in Section 2. In light of this discussion, Section 3 introduces and investigates different approaches to reducing methane emissions. Section 4 compares the policy approaches. Section 5 provides a synthesis of our findings and concludes.

2. Characterization of Methane Emissions from the Natural Gas Sector

In this section, we review the recent literature that characterizes methane emissions from the natural gas sector and explain how these emissions are quite different from conventional pollutants that policymakers have more experience regulating (e.g., carbon dioxide and sulfur dioxide). The performance of different policies, which we discuss at length in subsequent sections, will depend on how they address the particular nature of methane emissions from the natural gas sector.

Studies that measure methane emissions from the oil and gas sector use either a bottom-up or a top-down approach. The former relies on emissions factors (i.e., estimated methane emissions per piece of equipment), activity factors (i.e., the estimated number of certain types of equipment), and direct measurements at specific locations (e.g., taken using highly sensitive spectroscopy equipment that can detect tiny concentrations of methane in the air). Emissions are typically measured from aircraft, road vehicles, towers, drones, and satellites, and an atmospheric transport model is used to attribute emissions to anthropogenic sources (Danish 2014). The

number of bottom-up and top-down studies has increased dramatically in recent years, spearheaded by an effort led by the Environmental Defense Fund (EDF).

In general, the major drawback of bottom-up studies is that they rely on potentially unrealistic assumptions (e.g., about emissions factors, activity factors, or scaling a small sample of direct measurements to a larger population of sites), while the major drawback of top-down studies is difficulty in attributing observed methane fluxes to the correct anthropogenic source (Danish 2014). Bottom-up analyses have generally resulted in lower estimates of methane emissions than the top-down analyses. For example, a top-down approach yielded an estimate 60 percent higher than a bottom-up approach measuring the Barnett Shale play in Texas (Karion et al. 2015; Lyon et al. 2015). There are many potential reasons for this difference.[5] Recently, researchers reconciled the discrepancies in the Barnett Shale play estimates by reducing uncertainty in the top-down measurements (via repeated mass balance measurements) and improving the bottom-up measurements with more comprehensive activity factors as well as emissions factors that account for "super-emitters"—sites or equipment responsible for high levels of emissions (Zavala-Araiza et al. 2015). Notably, the aligned estimates exceed those of EPA. This study reveals that, from a technical point of view, it is possible to reconcile top-down and bottom-up estimates of methane emissions on a regional scale. However, it remains to be seen whether the economic costs of replicating the methodology

used in the study would be high enough to prevent additional estimates in other regions of the country.

Our review of the literature leads us to nine findings that may be thought of as unique attributes about methane emissions from the natural gas sector. Some of these attributes have implications for general policy design. Others create criteria against which different policies can be normatively compared, and we perform such a comparison later in the paper. In the following sections, we discuss the nine findings and note when one either has implications for general policy design or acts as a criterion that we use in comparing different policies.

2.1. Accurate Firm-Level Inventories of Methane Emissions are Currently Unavailable

Our first finding is that EPA likely significantly underestimates methane emissions from the US natural gas sector, although the inventory improves every year. EPA estimates originate from two efforts: the Greenhouse Gas Inventory (GHGI) and the Greenhouse Gas Reporting Program (GHGRP). The GHGI, published annually by EPA since 1998, estimates methane emissions from the natural gas sector at the national level. It takes a bottom-up approach that multiplies estimates of emissions factors and activity factors, primarily based on data collected two decades ago by Harrison et al. (1996). EPA updates the emissions and activity factors in the GHGI each year but must use data that are "public, citable, nationally applicable, and able to be applied over the entire historical series" (ICF 2016b, 4-2). Since 2009, the GHGRP has required large natural gas facilities—those that emit more 25,000 metric tons of CO_2—to report certain sources of methane emissions. EPA uses some of the data from the GHGRP to complement and revise methodologies employed in the GHGI.

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[5] One particularly interesting hypothesis to explain this discrepancy, posed by Fiji George from Southwestern Energy, is that top-down studies usually take measurements at a time of day when methane emissions peak.

Researchers have found underestimates in EPA's GHGI. Brandt et al. (2014) conduct an extensive literature review and find that measurements from the academic literature at all scales show GHGI inventories consistently underestimate actual methane emissions; they identify the natural gas and oil sector as an important contributor. Appendix 1 updates that literature review and displays two important trends. First, the more recent research continues to suggest that EPA tends to underestimate actual methane emissions. For example, Zavala-Araiza et al. (2015), the capstone study of EDF's measurement campaign in the Barnett, find that EPA underestimates emissions by about half. In a handful of notable exceptions, EPA's GHGI seems to overestimate emissions in certain segments of downstream subsectors (Lamb et al. 2015; Marchese et al. 2015; Zimmerle et al. 2015). Recent literature has examined the GHGRP, which is sometimes used as an input to the GHGI, so far finding that the GHGRP also consistently and sometimes dramatically underestimates actual methane emissions (Lan et al. 2015; Lavoie et al. 2015; Lyon et al. 2015; Subramanian et al. 2015).

Numerous explanations have been offered for these underestimates. First, activity factors in the GHGI may be inaccurate for certain sectors, a problem that in theory can lead to estimates either higher or lower than actual emissions but in practice seems to lead to underestimates. For example, Lyon et al. (2015) use more comprehensive activity factors and find that the Barnett Shale region emits more emissions than estimated by EPA's GHGI and GHGRP. Second, the samples used to calculate emissions and activity factors may be biased downward because they are taken from self-selected cooperating facilities and are therefore more likely to underrepresent high-emissions sources (Brandt et al. 2014). The GHGRP in particular is thought to underestimate actual emissions because it exempts important

sources from reporting and offers flexibility in how participants report emissions (Lavoie et al. 2015). Zimmerle et al. (2015) find an instance where the average emissions of facilities not participating in the GHGRP were 1.4 times larger than those of participating facilities, implying some degree of self-selection. Third, the Hi-Flo sampler (a measuring device approved for GHGRP use) has been attacked as being prone to fail (Howard 2015; Howard et al. 2015), and this implies that it may underestimate emissions, although this point is debated. Although similar failures in other instruments can occur (e.g., acoustic measurement devices have yielded erroneously low levels, as reported by Subramanian et al. 2015), the extent to which these failures are prevalent is unclear. Fourth, since a few super-emitters tend to emit the majority of methane emissions, sample sizes must be large to accurately reflect emissions across the population. EPA samples may be too small for in-sample emissions factors to capture enough super-emitters.

The main implication of our first finding is that it would be difficult to use any policy that requires an accurate firm-level methane inventory to reduce methane emissions. This is because, at the moment, firm-level methane inventories would most likely be based on emissions factors and activity factors used by EPA or collected through voluntary efforts led by EPA, and both of these data sources tend to underestimate methane emissions. To illustrate why this creates complications, it would be difficult under a pollution tax or an emissions trading system to ensure that the appropriate amount of emissions are taxed or an appropriate amount of pollution rights are allocated. While monitoring technologies are changing quickly and may allow for more accurate firm-level methane inventories in the future, we focus our efforts in this paper on crafting alternative policies that can perform relatively well, given these current data realities.

2.2. Each Stage of the Natural Gas Value Chain Is a Significant Methane Emitter

Our second finding is that the each of the natural gas subsectors—production, processing, transmission and storage, and distribution (Figure 2)—emits a significant amount of methane emissions. We now briefly review each subsector and a selection of potential emissions sources.

Production. The production subsector comprises nearly 500,000 wells (EIA 2015b). Operators vent methane upon well completion, a process during which the well is readied for production. In addition, natural gas extracted from a well contains hydrocarbon liquids that are separated from the methane, and this process releases methane. Operators separate from the gas a number of hydrocarbon liquids that release methane, which may be vented unless captured in a tank or flared. Finally, fugitive emissions result from operation of devices that use gas pressurization (in lieu of electricity, which is often not available at well sites) to perform correctly (ICF 2014).

Processing. Most gas contains enough impurities that it must be transported from the production site to a processing plant. As of 2009, the processing sector had 493 of these plants, with Texas and Louisiana accounting for nearly half of total processing capacity and 9 plants accounting for 31 percent of total processing capacity (EIA 2011). The gathering system between the production site and processing plant, as well as the processing plants themselves, can produce fugitive and vented methane (ICF 2014).

Transmission and storage. After purification, natural gas is transmitted to city hubs, often over great distances, and may be stored. The transmission sector comprises about 2,000 compressor stations distributed along some 300,000 miles of pressurized pipelines, underground storage facilities, and other equipment (Subramanian et al. 2015). The compressors that pressurize the gas are a primary source of fugitive and vented methane leaks for this activity (ICF 2014). Another is blowdowns, when a pipe is evacuated of gas for maintenance.

Distribution. Residential and commercial consumers receive gas through smaller distribution pipelines operated by local distribution companies. In 2013, there were more than 1 million miles of such pipelines. Although these lines do not require pressurization, they still may leak—especially if older—through lines, valves, connections, and metering equipment (ICF 2014). Jackson et al. (2014) show that leaks are relatively large for older East Coast cities (e.g., Boston, New York, Philadelphia) and smaller for newer cities and cities with major maintenance programs.[6]

Figure 3 displays the most recent annual estimate of national methane emissions, by subsector, from the five most recent annual GHGI reports. Emissions for each subsector change yearly (e.g., because of improved abatement efforts, updated methodologies, and new emissions and activity factors), and each subsector accounts for a significant portion of the sector's total methane emissions. That said, the inventory shows that the production and transmission sectors tend to emit more methane than the processing and distribution sectors.

The main implication of this finding is that a given policy, or set of policies, would likely need to regulate at least the production and transmission subsectors, and perhaps all subsectors, to efficaciously abate methane emissions from the nation's natural gas system.

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[6] Robert Jackson, Stanford, RFF Webinar, personal communication, September 13, 2016.

FIGURE 2. NATURAL GAS SUBSECTORS AND EXAMPLES OF KNOWN METHANE EMISSIONS SOURCES
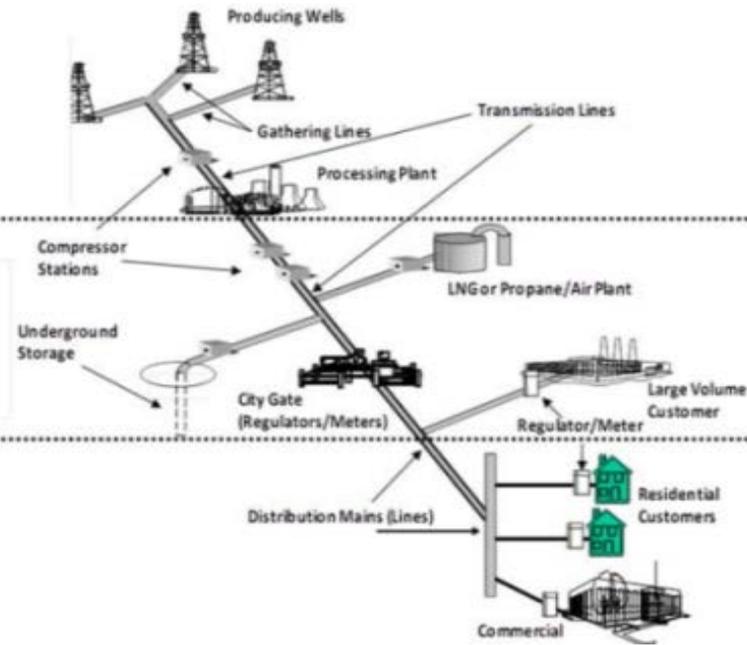
Source: ICF (2014).

FIGURE 3. METHANE EMISSIONS (MMTCO₂E), AS ESTIMATED BY EPA'S GREENHOUSE GAS INVENTORY, BY NATURAL GAS SUBSECTOR
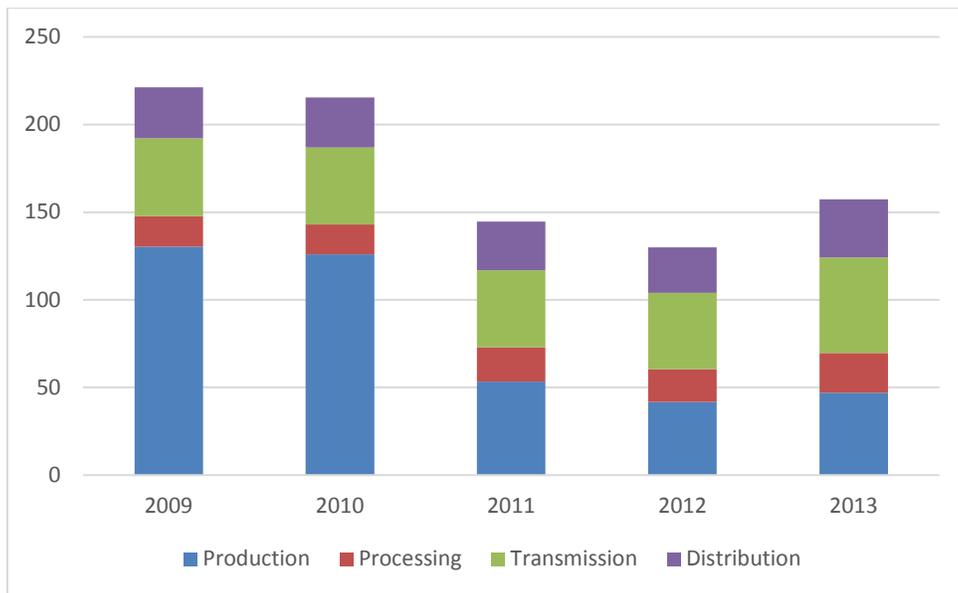
Source: EPA's annual GHGI reports, 2012–2016.

2.3. Abatement Costs are Heterogeneous across Subsectors

Our third finding is that there seems to be significant heterogeneity in abatement costs across the four natural gas subsectors. Figure 4 displays a marginal abatement cost curve for the subsectors in the Gulf Coast region, as estimated by ICF (2016a). Data collected from EPA's NG STAR program, members of ONE Future, and a study conducted by EDF each provided input into this analysis. The figure shows that marginal abatement costs, averaged within each subsector, range from less than $2 to more than $5 per thousand cubic feet (Mcf) of methane reduced, with the least expensive abatement in the production

subsector and most expensive abatement in the transmission and storage subsector. In a similar study, the National Renewable Energy Laboratory finds heterogeneity in abatement costs ranging from –$6 to $41 per metric ton of carbon dioxide equivalent, depending on whether the authors assume that regulated firms can recover revenue from captured methane, with the most expensive abatement coming from the distribution subsector (Warner et al. 2015). This finding implies that policies allowing for averaging or trading of abatement credits or allowances between subsectors will achieve more cost-effective abatement in aggregate than policies that do not offer this flexibility, all else being equal.

FIGURE 4. NATIONAL AGGREGATE MARGINAL ABATEMENT COST CURVE FOR OIL AND NATURAL GAS SUBSECTORS
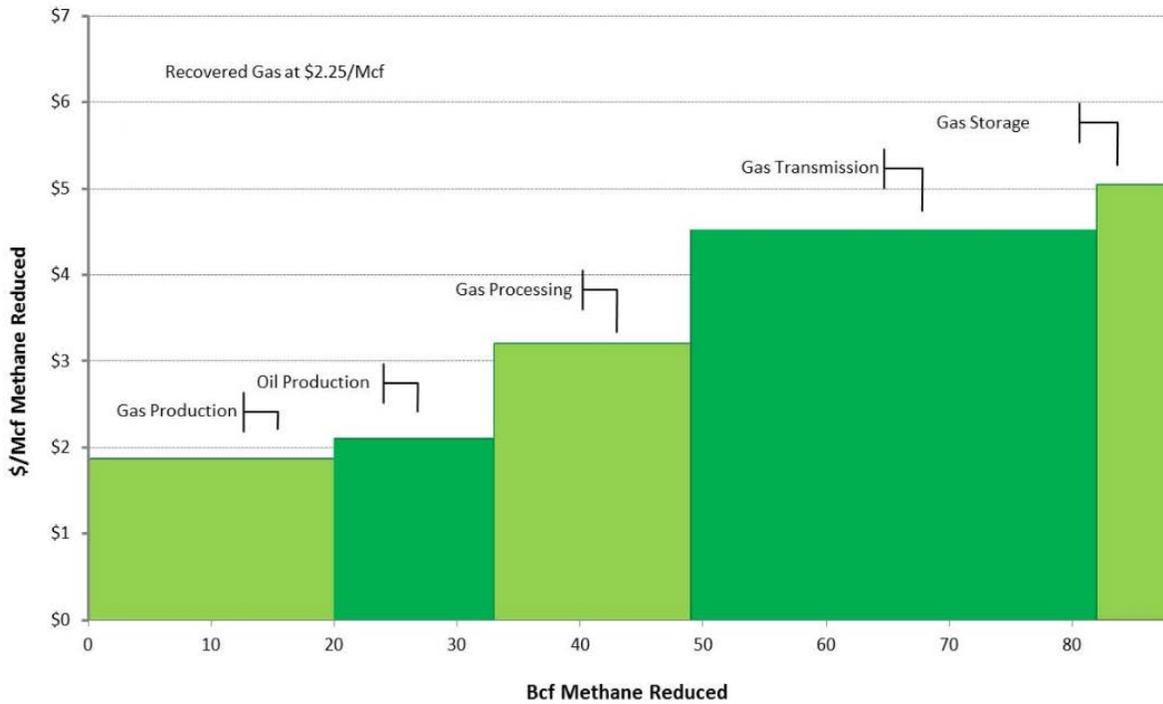
Source: ICF 2016a.

2.4. Abatement Costs are Heterogeneous across Technologies

Our fourth finding is that there seems to be wide heterogeneity in the costs of abatement technologies. Figure 5 displays a marginal abatement cost curve from ICF (2016a) based on specific abatement technologies in various subsectors, with values ranging from less than –$1 to nearly $8/Mcf of methane reduced. Moreover, the cost of the same abatement technology differs among subsectors. For example, replacing reciprocating compressor rod packing systems costs an estimated $8.81 per ton of carbon dioxide equivalent in the

production subsector and $14.42 in the processing subsector (ICF 2016a). This figure nets out economic benefits from recovered methane. In a similar study, the National Renewable Energy Laboratory finds heterogeneity in abatement costs ranging from –$10 to more than $40 per metric ton of carbon dioxide equivalent (Warner et al. 2015). This finding implies that policies allowing for averaging or trading of abatement credits or allowances between technologies will achieve more cost-effective abatement in aggregate than policies that do not offer this flexibility, all else being equal.

FIGURE 5. NATIONAL MARGINAL ABATEMENT COST CURVE FOR METHANE ABATEMENT TECHNOLOGIES FOR OIL AND NATURAL GAS SECTOR
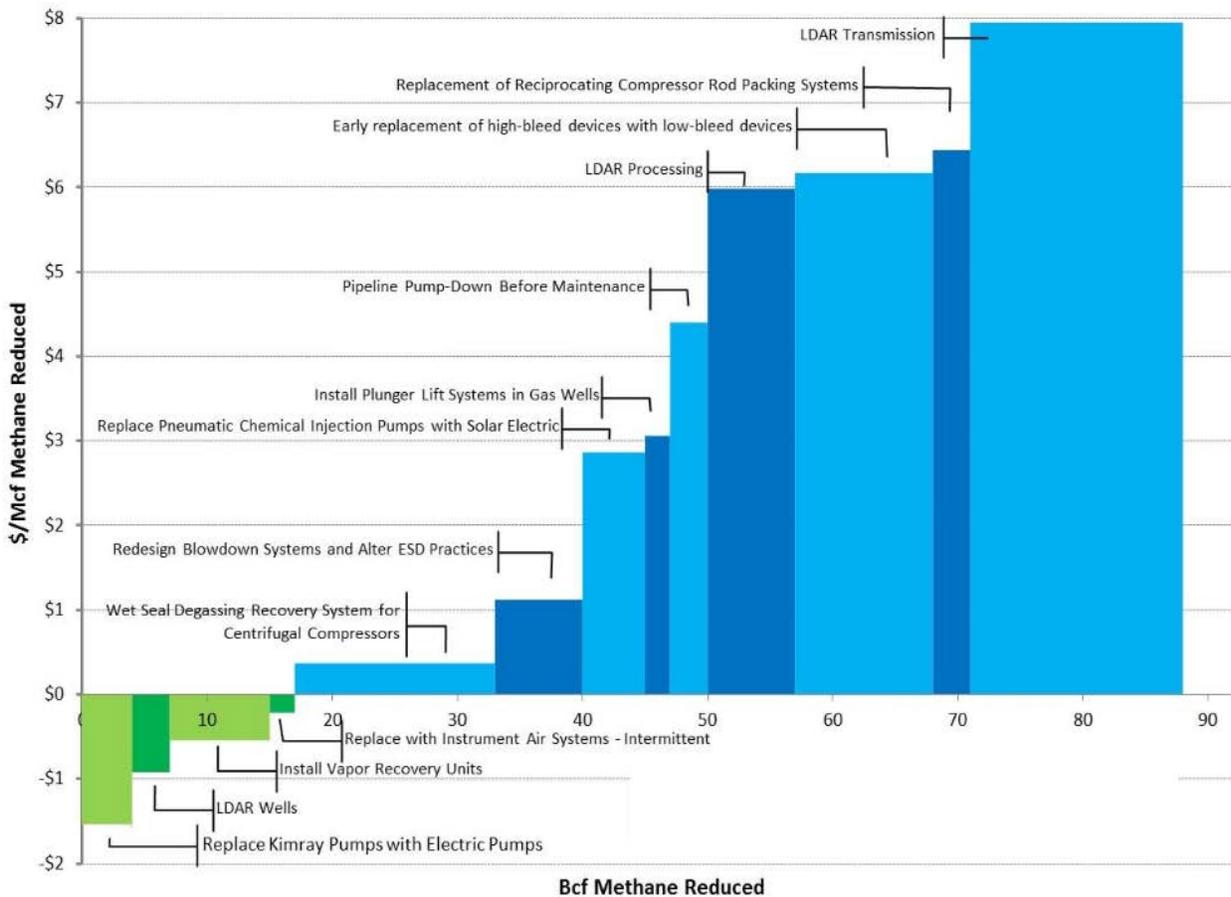
2.5. Methane Emissions Vary Widely within and across Regions

Our fifth finding is heterogeneity in methane emissions by location. For example, Peischl et al. (2015) estimate widely different leakage rates in the Fayetteville (1.0–2.8 percent), Haynesville (1.0–2.1 percent), and Marcellus (0.19–0.41 percent) production regions, via aircraft observation. Similarly, Rusco (2010) finds significant differences in leakage rates associated with flaring and venting of natural gas from onshore production sites in five basins. This trend seems to hold in downstream sectors as well. For example, methane emissions from a sample of hundreds of pneumatic pumps and controllers vary widely across the United States, as estimated by direct on-site measurements, with the lowest values differing by an order of magnitude compared with the highest values, which occurred in the Gulf Coast region (Allen et al. 2013, 2015). The authors' explanations for this regional heterogeneity include technology mixes and production rates that differ by region. Marchese et al. (2015) estimate leakage rates from gathering facilities in eight states ranging from 0.19 percent in Pennsylvania to 0.94 percent in Oklahoma. This variation may be partially explained by differences in geology, policy, practices, and procedures (Schneising et al. 2014).

These findings imply that certain regions might be expected to exhibit more abatement potential than others. In addition, insofar as this heterogeneity in emissions tracks to heterogeneity in costs, the findings would also imply that policies allowing for averaging or trading of credits and allowances between regions will achieve more cost-effective abatement in aggregate than policies that do not offer this flexibility, all else being equal.

2.6. Super-Emitters Account for Most Methane Emissions

Our sixth finding is that scientists repeatedly find a small number of units, termed super-emitters, responsible for the majority of methane emissions observed during the study period, as summarized in Appendix Table A3. A unit here can be defined as a site, a piece of equipment (e.g., a particular pneumatic valve), and categories of equipment (e.g., all pneumatic valves relative to other equipment classes).

Studies verify the existence of super-emitting sites across the natural gas value chain, from production (Alvarez et al. 2012; Caulton et al. 2014; Rella et al. 2015; Zavala-Araiza et al. 2015) and processing (Mitchell et al. 2015) to transmission and storage (Lyon et al. 2015; Subramanian et al. 2015; Yacovitch et al. 2015) and distribution. Zavala-Araiza et al. (2015) find that 15 percent of production sites contribute up to 80 percent of methane emissions from 186 sites in the Barnett Shale. A recent study (Brandt et al. 2016) finds that the largest 5 percent of leaks are responsible for 50 percent of emissions.

Particular pieces of equipment seem to be super-emitters within certain categories of equipment (Allen et al. 2015). For example, Zimmerle et al. (2015) find that 5 percent of the top-emitting pieces of equipment within a category emit 36 to 75 percent of methane emissions for that category, according to a national sampling of equipment for the transmission and distribution subsectors.

Finally, certain categories of equipment seem to be super-emitters across sites. For example, 22 of the more than 100 methane emissions categories that ICF (2014) considers across the natural gas value chain contribute 80 percent of total methane emissions.

These findings, taken together, suggest that a small group of sites, pieces of equipment, and categories of equipment

explain the majority of methane emissions at a particular point in time. This suggests that monitoring technologies that enable and policies that reward targeting of super-emitters would likely achieve abatement at relatively low costs.

2.7. A Significant Portion of Methane Emissions Seems to be Stochastic

We find that, based on their typical emissions profiles, super-emitters can be roughly split into three categories: chronic, episodic, and stochastic. Chronic super-emitters emit at a predictable and relatively static rate. Episodic super-emitters emit at a high rate but only for brief periods (e.g., during normal maintenance events, such as uploading and blowdowns). Stochastic super-emitters are created by leaks that result from operating errors and equipment malfunctions that are more difficult to predict and can occur in a seemingly random way.

The effectiveness of a given policy importantly depends on the extent to which super-emitters tend to be chronic, episodic, or stochastic. Brantley et al. (2014) find that variability in production rates (which might be expected to be positively correlated with leaks) explains only 10 percent of the observed variability in methane at a sample of production sites across Colorado, Texas, and Wyoming—lending support to the hypothesis that stochastic super-emitters are important in determining observed methane emissions. In addition, Nathan et al. (2015) use a model aircraft with a laser-based methane sensor to characterize emissions at a compressor station, finding that methane emissions varied substantially, from 0.3 to 73 grams of methane per second, over time (hours to days); this serves as a caution about the reliability of measurements taken over short durations and implies that these emissions are episodic or stochastic in nature. The data are limited at this time, since most studies characterize

methane emissions over relatively short durations of time. Nonetheless, the weight of evidence suggests that a significant portion of emissions comes from the stochastic super-emitters (Zavala-Araiza et al. 2017).

Policies that incentivize the identification and abatement of all three types of super-emitters will be more environmentally effective and perhaps economically efficient than other policies, all else being equal. Therefore, the monitoring strategy that each policy employs to identify methane emissions—which could range from traditional inventories based on emissions or activity factors to the use of conventional or innovative approaches to detect methane emissions—is a particularly important aspect of policy design. Presumably, chronic super-emitters are the easiest category to monitor, followed by episodic super-emitters (at least a portion of which should be predictable, if not measurable, so long as maintenance schedules are known), with stochastic super-emitters being the most difficult to monitor. This finding highlights the important role that monitoring strategy plays in how well a particular policy performs. We therefore discuss monitoring strategies in detail when we describe each policy in the next section.

2.8. The Upstream Part of the Natural Gas Sector (Well Development) is Dominated by Many Low-Production (Marginal) Wells and Small Firms

Of the more than 1 million gas and oil wells operating in the United States, most are marginal wells with production of less than 90 Mcf per day; cumulatively, these marginal wells represent 10 percent of production and are typically owned by small firms with 12 or

fewer employees.[7] Given the low production and limited staff of these producers, it is worthwhile to carefully consider whether to regulate them under a policy that reduces methane emissions. Regulation may be warranted if small, marginal wells are at least as likely to be super-emitters as larger wells, since one could expect regulation of such wells to yield larger benefits. On the one hand, one could expect a lower frequency of super-emitters among the small, marginal wells because their throughput is so small and operators have incentive to discover and fix leaks that would be a large fraction of output. On the other hand, such operators may not have the financial capability to implement best management practices—not only to fix leaks when they occur but also to lower leak probability. We conducted an initial analysis on wells researched by Rella et al. (2015) and Lan et al. (2015), finding that while some marginal wells in these datasets are super-emitters, these wells also perform fewer unloadings and have fewer pneumatic controllers, which may reduce the probability of leaks occurring. We also find a small but statistically significant positive relationship between production and methane emissions, which comports with prior research. While more research is needed, we argue that it is prudent to focus first on the bigger emissions, which will likely be more cost-effective to address, and to set a compliance threshold for wells based on the absolute number of emissions they emit. The precise value for such a threshold depends on context and is a topic for future research to address.

2.9. There are Institutional Barriers to Reducing Methane Emissions

Our ninth finding is that there are clear institutional barriers to methane capture. For example, in most states, public utility commissions do not allow local distribution companies to fully recover costs associated with repairing pipeline leaks (Chimowitz et al. 2015; Jackson et al. 2014) because the costs of discovering and fixing small leaks are considered maintenance expenses. In short, such costs are not put in the rate base because they are a cost of doing business (Hausman and Muehlenbachs 2016). The discovery of potentially explosive leaks—referred to by pipeline companies as Grade 1 leaks—in distribution systems serving Boston and Washington, DC, further highlights a clear lack of incentives for companies to abate methane emissions (e.g., Phillips et al. 2013; Jackson et al. 2014).

Other natural gas subsectors may also suffer from such principal-agent issues. Contracting is common in many aspects of the production subsectors, for example, and contractors may not be fully incentivized to reduce methane emissions if their contracts do not explicitly reward such behavior. The example in the distribution sector is simply the most apparent situation in which incentives for abatement are misaligned. This situation implies that, in order to be effective in reducing methane emissions from the distribution sector, policies may have to be complemented by reform in how state utility regulators treat the costs of repairing pipeline leaks.

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[7] See Today In Energy, July, 29, 2016: https://www.eia.gov/todayinenergy/detail.php?id=26872 and IPAA's Profile of Independent Producers: http://www.ipaa.org/wp-content/uploads/downloads/2014/07/2012-2013ProfileOfIndependentProducers.pdf

3. Alternative Approaches to Reduce Methane Emissions from the US Natural Gas Sector

The findings from the literature described above create a set of stylized facts that highlight the unique aspects of methane emissions from the natural gas sector in the United States. The performance of different policies, the focus of Section 4, will depend on how they address those stylized facts. This section introduces a suite of conventional and flexible policies, describing how they might work before posing practical and research questions that need to be answered.

Economists typically identify four categories of policies to reduce emissions: voluntary approaches, technology standards, performance standards, and market-based policies. As previously mentioned, EPA has operated a voluntary approach (NG STAR) for more than two decades, and operators have recently advanced their own voluntary approaches, perhaps most notably ONE Future, which emerged in 2014 and is now officially part of EPA's voluntary programs (see Box 1, which discusses other voluntary approaches). We choose not to focus on voluntary approaches as a separate type of policy because thus far, the voluntary programs, such as ONE Future, have characteristics quite similar to a performance standard—for example, a standard of one percent methane emissions over the value chain (see Appendix 2).

The governments of California, Colorado, Pennsylvania, and a few other states turned to regulation in the early 2010s. The Obama administration took a combined technology and performance standards approach to regulating new and modified sources when EPA proposed and finalized regulations under Section 111(b) of the CAA, requiring leak, detection, and repair programs. BLM's approach for limiting methane emissions from oil and gas operations on federal land took a similar approach.

In contrast to voluntary and standard-setting approaches, market-based policies (such as taxes and trading programs) have not been widely discussed in the context of methane emissions. One reason for this is that, from an administrative point of view, it seems impossible to craft a classic carbon tax or emissions trading system (ETS) for methane, given that governments do not have accurate and publicly available inventories of firm-level methane emissions. The lack of such inventories means it would be difficult to set an appropriate tax rate or cap level, identify a tax or emissions base, and enforce compliance, as with a classic carbon tax or ETS. Both EDF and the Department of Energy have ongoing projects (the Methane Detectors Program and MONITOR program, respectively) to improve the state of methane emissions detectors; better monitors could reduce monitoring costs and improve emissions inventories. But the status quo is inadequate to support a classic trading program. What is needed, then, at least in the short term, is market-based policies that are robust to insufficient information. We introduce one such policy below—a tax with default and updatable leakage rates—although many other, similar options might exist, and any such policy would need much scrutiny, fine-tuning, and testing before it could be implemented.

In this section, we introduce the following prototypical policies, which can be split into two groups. The first group includes (1) technology-based standards for certain types of equipment; (2) performance standards for certain types of equipment; (3a, 3b) two types of conventional LDAR programs; (3c) an innovative LDAR program, as described by

Kemp et al. (2016); and (4) performance standards with averaging at the firm level within each natural gas subsector.[8] We then discuss a second group of market mechanisms that are both adapted to the stylized fact that the continuous emissions monitoring capabilities needed for a classic emissions tax or tradable permit system are not yet available. These policies include (5) a tradable performance standard that allows for trading across firms and natural gas subsectors, based on assumed emissions and activity factors; and (6) a tax with default and updatable assumed leakage rates.[9] These six prototypical policies are intended to capture the essence of each approach while abstracting away from specific details, which we relegate to Box 1 and the appendixes; doing so allows us to more tractably compare the policies' theoretical strengths and weaknesses. We describe the policies below.

3.1. Policies

3.1.1 Technology-Based Standards on Equipment

As the name implies, technology standards prescribe a certain technology that polluters must use.[10] For methane, a technology standard might require a polluter to install or replace a certain type of equipment (e.g., replacing rod packing in compressors to reduce leaks) or use a certain technological process during the operation of equipment (e.g., capturing methane that typically escapes into the air when a production well is completed, known as a "green completion") (Danish 2014).

3.1.2. Performance Standards on Equipment

Unlike technology standards, which prescribe a specific technology for the affected source in an attempt to achieve an emissions goal, performance standards give the operator discretion regarding how reductions are achieved. Performance standards on equipment might require a polluter to reduce emissions from certain types of equipment, either below baseline emissions levels (e.g., pneumatic pumps must reduce methane emissions by 95 percent) or at a maximum rate of emissions (e.g., emissions from pneumatic controllers must not exceed 6 standard cubic feet per hour).

3.1.3. Leak Detection and Repair Programs

Leak detection and repair (LDAR) programs are unique in that they prescribe monitoring frequency (e.g., a few times per year at a facility or equipment location) and require that a violation (i.e., a leak) be corrected. In addition, they may specify that a particular monitoring technology be used.

Monitoring is typically done with optical gas imaging (usually a hand-held infrared camera) that identifies leaks above a certain threshold but without measuring concentrations. Occasionally, optical gas imaging is combined with high-volume sampling that estimates the rate of methane being emitted from a particular source (e.g., a single compressor), usually in standard cubic feet per hour, which allows for an approximation of the total volume of methane emitted by that source. However, this

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[8] This represents a mandatory version of the ONE Future track of EPA's Methane Challenge Program.

[9] Although recent research suggests it may be possible to craft an ETS that endogenously allocates allowances and incentivizes firms to reveal their methane emissions to the government, we view the research in this field as too preliminary to inform a prototypical policy for this paper.

[10] Technically, a technology-based standard is a target number based on a specific technology, although in practice firms often use the designated technology underlying the standard because using a different technology may cause problems if it does not meet the standard.

approach is expensive. Novel approaches to monitoring methane emissions are being explored, if not widely implemented, including distributed detectors (placed downwind of a site, alerting repair crews when threshold concentrations of methane are reached) and automated infrared imaging by an aerial drone, which flies over sites and detects leaks, sending images to repair crews when necessary (Kemp et al. 2016). Relatively inexpensive airplane and satellite approaches to methane detection are also being developed.

The economic merits of these programs depend strongly on the value of captured methane versus the monitoring and repair costs. Monitoring costs have several variables, including the monitoring technology used; the labor costs associated with that technology; the spatial distribution, frequency, and duration of monitoring; the number of measurements to be taken at any one time; and whether emissions are simply detected or also measured (see, e.g., Saunier et al. 2014). We consider three versions of LDAR programs, based on Kemp et al. (2016):

3a. LDRO, or LDAR with hand-held optical imaging technology. This technology reveals whether a leak has breached a certain threshold, but it cannot quantify the rate or absolute value of emissions caused by a leak. It imposes significant monitoring costs because of the labor involved in operating infrared cameras.

3b. LDRS, or LDAR with sampling. This program requires polluters to monitor leaks using hand-held optical imaging and then, after a leak has been identified, to use a high-volume sampler that estimates the methane emissions rate (measured in standard cubic feet per hour) at each identified leak. It imposes relatively high monitoring costs because of the labor involved in operating infrared cameras and using high-volume samplers. But because polluters can roughly approximate the total volume of methane

emissions avoided by repairing the leak (by multiplying the observed hourly emissions rate by an estimate of the number of operating hours of the piece of equipment or process that has been leaking), one can roughly approximate the total abatement achieved by the program. This type of LDAR program is not commonly used in practice; high-volume samplers are more typically used by academics to research methane fluxes from sites.

3c. LDRL, or LDAR with large-scale imaging technology. Satellites, planes, or aerial drones would detect a leak from methane's infrared signature, and ground crews would follow up to pinpoint the source. This type of LDAR program imposes relatively low monitoring costs—for example, drones could quickly scan many sites—but with current technologies, it would be able to identify only relatively large methane leaks. To our knowledge, no LDAR program currently requires the use of large-scale imaging, but the underlying technology is being further developed and improved.[11] LDAR programs could make even greater use of tiered approaches. Duren and Miller (2016) propose a four-tier system starting with satellites and then involving aircraft, drones, and finally work crews.

3.1.4. Performance Standards on Facilities or Firms

Performance standards can also be placed on facilities or firms. A facility would be defined geographically and could include, for example, a set of producing wells on a pad as well as dewatering and other equipment on site. A firm would be defined by ownership,

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[11] The LDAR programs we discuss could be layered on top of another. For example, Duren and Miller (2016) propose a four-tier system starting with satellites and then involving aircraft, drones, and finally work crews.

where the methane emissions originating from all the equipment and processes owned by a given entity (e,g., a corporation or privately owned company) would constitute that entity's emissions (perhaps limited to a given region, such as a state). A performance standard could require a facility or firm to keep emissions at or below a certain maximum leakage rate, expressed in terms of tons of methane emissions, from all of that firm's equipment and processes divided by tons of methane throughput for those equipment and processes, in the aggregate. Or a performance standard could require a facility or firm to reduce emissions a certain percentage below its baseline levels, in aggregate.

For example, if a firm owns a single distribution pipeline, its emissions rate would be calculated as all the estimated methane emissions from that pipeline via known emissions sources (i.e., equipment and processes) divided by the methane that travels through that pipeline. This allows for a type of averaging: individual equipment and processes can emit varying amounts so long as the aggregate rate for the entire facility or firm is below the maximum. If ONE Future's voluntary system were made mandatory, it would be described as a performance standard on the firm over its many sites.[12]

3.1.5. Tradable Performance Standard

Performance standards can also be placed on a collection of firms or plants owned by multiple firms. We imagine a performance standard that takes the following form: the regulator assigns a natural gas subsector an emissions rate, expressed in terms of that

subsector's aggregate methane emissions divided by tons of methane throughput for that subsector. If any firm within this sector emits below the subsector's emissions rate, it receives a number of tradable credits equal to the difference between the subsector's emissions rate and its own emissions rate multiplied by that firm's methane throughput. If a firm within this sector is calculated to emit above the subsector rate, it can purchase these tradable credits and count them toward compliance. In this way, individual firms can be above or below the overall emissions rate for the subsector so long as the subsector meets its emissions rate goal in aggregate. This approach has been intellectually explored in the context of regulating carbon under the Clean Power Plan (Burtraw et al. 2011). The benefits of such a plan are the flexibility it provides in reaching compliance and the associated expected cost savings.

3.1.6. Tax with Default Leakage Rates

Under this approach, a firm would be taxed for each ton of methane emissions, estimated based on default emissions factors and activity factors. That is, instead of requiring that each firm attempt to monitor and report its methane emissions, the regulator would estimate each firm's emissions using default assumptions about emissions factors (tons of methane emitted by certain equipment and processes in a given year) and activity factors (the number of equipment and processes owned by that firm). A firm that believes that the default assumptions overestimate its methane emissions could petition for those assumptions to be lowered, and the regulator could grant this petition if the firm's evidence were found compelling. Of course, this would require that the government assess whether the petitioner has accurately estimated its methane emissions. Standards or guidelines for petitions could be set within the originating regulation. This

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[12] This averaging could be expanded to cover multiple firms in the same industry segment or even across industry segments; ONE Future has stopped short of this.

would incentivize firms to invest in research and development for monitoring technologies.

Such a novel approach raises a number of issues:

- If a tax were to be levied, what would be the tax base? One option would be to tax each ton of methane emissions.
- What would be the tax rate? One option would be to tax at the social cost of methane (Marten and Newbold 2012). However, in practice, carbon prices are typically not set at the global social cost of the emissions' damage. Thus it is imaginable that a lower tax would be implemented. Important considerations in identifying a rate are the extent to which the price is expected to reduce emissions and the expected marginal abatement cost curve for the covered polluters.
- How would the regulator estimate default emissions factors and activity factors? EPA collects default emissions factors for certain pieces of equipment. However, these factors tend to underestimate emissions levels, as discussed in Section 2. One strategy would be to multiply all default emissions factors by a factor greater than one in an effort to make these factors more accurate and to induce firms to collect and share more data on their emissions. Moreover, firm-level activity factors may not be publicly available.

3.2. General Practical Questions

We have described prototypical approaches rather than real-life policies because the detailed analysis required for actual policies would distract from the basics of matching the stylized facts (Section 2) to general policy features. In this subsection, we discuss a few specifics that some or all of these policies would need to address before they could be debated.

How would leaks be quantified? There are a variety of ways to quantify methane emissions and methane throughput, which is required for some policies. The simplest way to quantify emissions is to rely on a calculation that multiplies activity and emissions factors (insofar as these data are publicly available), but it may be advantageous to attempt to directly calculate methane emissions using a variety of technologies. While quantifying methane throughput, care must be taken to account for impurities, hydrocarbon liquids at coproducing sites in the production sector, and measurement error due to calculation uncertainty and theft. In addition, the regulator needs to decide whether to normalize emissions to total gas production or total energy production.[13]

Would credit be granted for prior performance? Regulators may or may not choose to reward firms, facilities, or states that have shown a strong track record of reducing methane emissions.

How would co-pollutants be taken into account? Volatile organic compounds (VOCs) and toxic compounds can be co-emitted with methane. A policy that allows for spatial averaging or trading of methane emissions can therefore lead to hotspots of VOCs or toxic compounds. For an area in or nearing nonattainment with National Ambient Air Quality Standards, this could pose a significant regulatory risk. Moreover, VOCs are a significant cause of concern for public health, since they can be carcinogenic and a precursor for ozone.

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[13] Thanks to David Lyon for this point.

4. Comparison of Policies

In this section, we compare the policies introduced above using three criteria: administrative costs, economic efficiency, and environmental effectiveness. Although other criteria and prototypical policies could certainly be considered, this initial and idiosyncratic analysis is intended to prompt further and more elaborate discussion.

Administrative costs are incurred by the regulator to monitor and enforce the policy, conditional on the policy already being promulgated. We do not consider industry costs as part of this criterion.

Economic efficiency has at least two interpretations: whether the policy equates marginal benefits with marginal costs (which is considered optimal from an efficiency point of view) and, more broadly, whether the policy promotes cost-effective abatement. We focus on the latter interpretation and consider two aspects that reflect the effort that a company must make to comply with the prototypical policy: the cost of reporting, if any, to the government; and abatement costs, including the costs of identifying methane emissions, installing and operating certain technologies, repairing methane leaks, and if necessary, proving compliance. Policies that grant polluters the flexibility to take advantage of the wide heterogeneity in abatement costs (e.g., a policy that allows selective targeting of super-emitters) will outperform more restrictive policies. We do not consider costs to the regulator for this criterion. We also do not consider dynamic economic efficiency— that is, how well a policy performs (in efficiency terms) over time as technologies and other factors change.

Environmental effectiveness refers to the policy's potential for reducing methane emissions: the greater the potential reduction, the greater the environmental effectiveness. For this criterion, we assume that each policy aims to achieve the same level of stringency and would thereby achieve the same abatement, in principle. However, for many of the policies we investigate, confirming abatement, emissions levels, or even emissions sources at any one point in time could be complicated by the lack of reliable firm-level inventories. To characterize this complexity, we focus on three aspects of environmental effectiveness: whether a policy would incentivize the abatement of emissions from episodic or stochastic emitters; whether it would incentivize improvements in emissions inventories; and whether it is capable of providing certainty in abatement or emissions outcomes.

Before comparing the policies, we recall five of the nine findings from our literature review in Section 2 that we deem as important criteria against which different policies can be normatively compared.[14] These are the findings that we use in comparing the performance of different policies.

- *Abatement costs are heterogeneous across subsectors.* This implies that policies allowing for averaging or trading of abatement credits or allowances between subsectors will achieve more cost-effective abatement in aggregate than policies that do not offer this flexibility, all else being equal.

- *Abatement costs are heterogeneous across technologies.* This finding implies that policies allowing for averaging or trading of abatement credits or allowances between technologies will achieve more cost-effective abatement in

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[14] The remaining four findings have implications for general policy design, which we discussed in previous sections, but do not necessarily address differences in performance among policies.

aggregate than policies that do not offer this flexibility, all else being equal.

- *Methane emissions vary widely within and across regions.* This finding implies that, insofar as this variance in emissions tracks with variance in costs, policies allowing for averaging or trading of credits and allowances between regions will achieve more cost-effective abatement in aggregate than policies that do not offer this flexibility, all else being equal.

- *Super-emitters account for most methane emissions.* This finding suggests that monitoring technologies that enable and policies that reward targeting of super-emitters would likely achieve abatement at relatively low costs.

- *A significant portion of methane emissions seems to be stochastic.* This finding implies that policies that incentivize the identification and abatement of all three types of super-emitters (chronic, episodic, and stochastic) will be more environmentally effective and perhaps more economically efficient than other policies, all else being equal.

We reemphasize the crucial role that methane monitoring technologies play in determining which policies are implementable. These technologies cannot currently provide inexpensive and reliable firm- or facility-level inventories of methane emissions, and thus typical market-based approaches that impose a price on each ton of emissions (e.g., a tax or emissions trading system) are not practical policy options today. However, monitoring technologies are improving quickly, which makes firm-level inventories of methane emissions a possibility in the near future. If such inventories were available, then the typical market-based approaches would be more feasible.

Methane monitoring technologies also play a crucial role in determining the performance of a policy. How, for example, would regulators effectively monitor enforcement with a performance standard that applies to all facilities in the transmission and distribution subsectors? With current technology, one approach would be to check a sample of equipment from these sectors with hand-held infrared devices and high-volume samplers. However, under this arrangement, regulators would likely be able to check compliance at only a small number of sites, given the more than 1.3 million miles of transmission and distribution pipelines. If improved monitoring technology allowed cheaper measurement of methane emissions from equipment and sites, then enforcing this type of performance standard, for example, could become much easier. In general, monitoring technologies interact with each of our prototypical policies in similar ways; while we try to cover the most obvious of these interactions, we leave a more comprehensive analysis for future research.

We now turn to a description of each policy and a discussion of how the policy performs according to the three criteria we identified.

4.1. Technology-Based Standards on Equipment

Administrative costs. For methane emissions, which are not easily observable, the appeal of technology standards is apparent. Known technologies can reduce these emissions, making it tempting for the regulator to prescribe and monitor their installation. Yet the number of emissions sources from the natural gas sector is enormous, and the number of technologies required to achieve reductions from each source is significant. Thus ensuring that firms have installed and are using these technologies, and enforcing penalties against

firms that are in noncompliance, could be a massive undertaking.

Economic efficiency. In terms of compliance costs, technology standards tend to perform well when one abatement technology is clearly superior to others, and regulations that require that technology create economies of scale (Sterner and Coria 2012). However, it is far from clear which one technology, if any, is superior at abating methane emissions from the natural gas sector. More likely, emissions come from a wide variety of sources that need to be addressed by a wide variety of technologies. Unfortunately, technology standards provide little if any flexibility to regulated entities regarding which technologies to use to reduce emissions. Moreover, it seems that technology standards tend to require the universal adoption and continuous use of particular technologies for specific sources, instead of allowing regulated entities to target their abatement efforts to particularly problematic sources (e.g., super-emitters). Finally, if abatement technologies change faster than the technology standards can be updated, then these concerns are exacerbated. Overall, therefore, technology standards are inefficient, meaning costs to reduce emissions are likely higher than they need to be.

Environmental effectiveness. The environmental effectiveness of a methane technology standard depends on the cause of the emissions and the relative share of emissions from different categories (chronic, episodic, or stochastic). We know about the sources of methane emissions as well as the abatement technologies, thanks to efforts by EPA and industry through the NG STAR program. But it is less certain whether most methane emissions originate from suboptimal technology, poor work practices, or equipment malfunctions and human operating error (e.g., Brantley et al. 2014). If the last two categories, which are examples of episodic or

stochastic emissions, explain a significant portion of methane emissions, then technology standards will miss at least some opportunities—and perhaps low-cost ones—for abatement. In addition, technology standards do not encourage regulators or regulated entities to improve their emissions inventories. They do provide a way to estimate abatement attributable to the policy (assuming a default leakage rate before and after a technology is installed, and multiplying by the number of installations), but this calculation might be overly simplistic.

4.2. Performance Standards on Equipment

Administrative costs. Performance standards on equipment necessitate estimating baseline emissions levels (i.e., levels that would have occurred in the absence of the policy intervention) in order to require a percentage reduction below these levels, or measuring emissions rates in order to set a maximum. Neither type of data are widely available. As with technology standards, monitoring and enforcement for a vast number of sources that use different technologies could be a massive undertaking. One option to reduce administrative costs would be to require firms to estimate their emissions levels or rates; these estimates would entail significant effort on the part of the firms, however, and would also need to be periodically verified by the government.

Economic efficiency. Compared with technology standards, performance standards give operators more flexibility in choosing which technologies or practices they use to reduce emissions, which improves the cost-effectiveness of abatement. However, as with technology standards, performance standards apply to all pieces of equipment, which precludes the ability to prioritize abatement at super-emitting equipment. In addition, performance standards do not allow for cost

savings from heterogeneity in abatement costs across different emissions sources and across natural gas subsectors.

Environmental effectiveness. Performance standards have the drawback that if they are rate based, an increase in the number of devices of a given type will raise emissions even if the standards are met. Similarly to technology standards, if episodic or stochastic emissions explain a significant portion of methane emissions, then performance standards will miss at least some opportunities for abatement, perhaps low-cost ones.

4.3. Leak Detection and Repair Programs

Many of the policies we discuss involve some element of detecting and repairing leaks, but this section focuses on a comprehensive leak detection and repair (LDAR) program (such as the one in place in Colorado) as a policy in and of itself. We discuss LDAR programs in general terms but distinguish among the previously mentioned LDAR programs when necessary: LDRO, LDRS, and LDRL.

Administrative costs. Perhaps one of the appeals of LDAR programs for regulators is that monitoring of methane emissions could largely be transferred from the government to regulated entities. However, regulators must ensure that regulated entities are regularly and thoroughly searching for leaks, and repairing them when required; this necessitates on-site visits from auditors (for LDRO and LDRS) for enforcement to work well. Therefore, while the governmental costs of monitoring installations are quite low, enforcement costs might be high. It is important to consider different variations of enforcement strategies,

and drawing on states' experience with LDAR programs would be prudent.

Economic efficiency. There are four cost elements: type of monitoring equipment, frequency of monitoring,[15] costs of fixing the detected problems, and costs of proving that the repair work was performed (e.g., reporting, auditing, or further monitoring). In general, LDAR policies require abatement only when an unintentional leak is actually identified, avoiding forced installations at equipment where leaks may not occur. They also allow for prioritization of leak surveys and repairs, which facilitates the identification and repair of super-emitters. However, the economic efficiency of LDAR policies importantly depends on the method the polluter must use to identify leaks; this motivated us to craft three specific LDAR policies, which we now evaluate.

The LDRO program involves particularly high reporting costs, since polluters must estimate the emissions rates of leaks after they are identified with infrared cameras. Comparatively, the LDRS program involves lower reporting costs, yet polluters must still conduct on-site surveys with infrared cameras, which are high in labor costs. Finally, the LDRL program uses the most advanced technology but is able to scan sites quickly and remotely for larger leaks, making it a

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[15] One of these factors includes the frequency of the surveys (e.g., quarterly, semiannually, or annually). The appropriate monitoring frequency is highly contentious because so little is understood about the super-emitter population. Stochastic emissions demand greater frequency and chronic emissions demand lower frequency. Episodic emissions may be correctable without monitoring if they are associated with specific known processes or equipment designed for venting, or may not be correctable if they are not caused by routine processes.

relatively low-cost way to identify methane emissions (Kemp et al. 2016).

We note that elements of these and other LDAR programs might be tiered. For example, an LDRL program could be used to identify which sites should be subject to an LDRO program. This tiered system would likely be more economically efficient because labor costs for site visits would be restricted to sites that emit enough methane to be detected via remote sensing.

Environmental effectiveness. An attractive feature of LDAR programs in general is that they are agnostic regarding the cause of an emissions source. All significant emissions originating from chronic, episodic, and stochastic emitters would presumably be detected and repaired. However, the probability that these errors are detected depends on a variety of factors, including, inter alia, the methods used to detect leaks and the survey frequency. In this context, the LDRO and LDRS policies enjoy an advantage over the LDRL policy. The first two policies require on-site surveys with infrared cameras and therefore can detect smaller leaks; the third policy requires aerial surveys with infrared cameras using aircraft drones, which can detect only larger leaks, so smaller leaks may not be addressed (Kemp et al. 2016). All these forms of LDAR programs may help improve emissions inventories if polluters share, or are required to share, their survey information with the regulator. Moreover, the LDRS policy allows for a relatively sophisticated way to measure abatement achieved by the policy itself, which could be valuable information.

4.4. Performance Standards on Facilities or Firms

Administrative costs. An example of a voluntary firm-level performance standard is the ONE Future approach, in which methane emissions are limited to *x* percent of natural gas throughput. In this section, we essentially discuss a mandatory version of this approach. To implement this approach, the regulator must estimate not only methane emissions from that firm but also methane throughput, the data collection of which would come with additional costs.

Economic efficiency. In the context of methane emissions, the performance standard on firms allows for a type of averaging that affords regulated polluters the flexibility to choose the technologies and (if the firm spans multiple natural gas subsector and regions) the subsectors and regions that abatement comes from. These flexibilities would mean that performance standards on firms would exploit wide abatement cost heterogeneities that are identified in the literature between different emissions sources and subsectors, providing improved cost-effectiveness.

Environmental effectiveness. This criterion is similar to that for performance standards on equipment, unless the regulator measures methane emissions in a way that also captures leaks from episodic and stochastic emitters (e.g., by using a top-down approach to rectify bottom-up approaches). In this case, the performance standard on firms might pick up and encourage the abatement of more emissions than a performance standard on equipment. In addition, as mentioned previously, performance standards do not directly improve emissions inventories.

4.5. Tradable Performance Standard

Administrative costs. The costs are similar to those for a performance standard on firms. However, there is an additional cost: regulators must oversee a pollution rights market, since credits would need to be issued, tracked, and retired across firms.

Economic efficiency. A tradable performance standard improves on the efficiency of a performance standard on firms or facilities by broadening the averaging or

trading horizon across operators and possibly across states and across firms in other stages of the natural gas value chain, allowing regulated entities to further take advantage of abatement cost heterogeneities found in the literature. To gain such cost savings will itself incur costs, since the reporting and monitoring burdens are higher than for a performance standard without the trading.

Environmental effectiveness. This is similar to performance standards on firms, unless the regulator measures methane emissions in a way that also captures leaks from episodic and stochastic emitters (e.g., by using a top-down approach to rectify bottom-up approaches). In this case, the tradable performance standard might pick up and encourage the abatement of more emissions than a performance standard on equipment. In addition, as mentioned previously, tradable performance standards do not directly improve emissions inventories. The main advantage of tradable performance standards is the increased cost-effectiveness.

4.6. Tax with Default Assumed Leakage Rates

Administrative costs. Monitoring and enforcement costs to the government could be relatively low under an approach that imposes a tax on a firm with assumed default emissions and activity factors. The regulator would have to estimate factors for firms that accept default rates and verify these factors only on the subset of firms that petition for lower values. However, administrative costs would therefore be quite sensitive to how many firms petitioned for lower factor values, increasing as the number of petitioning firms increases. At the same time, the tax generates revenues, which could be used to offset such costs. This approach is much simpler in terms of reporting and tracking than a tradable performance standard because there are no tradable pollution rights.

Economic efficiency. An advantage of the tax approach is that firms can reduce emissions however they would like, which reduces compliance costs. Reporting costs are quite small if the firm accepts the default rate but are significant if the firm wants to petition the regulator for lower assumed default emissions and activity factors. One potential downside is that if a firm's calculated emissions levels are much lower than its actual emissions levels, then economic efficiency would be compromised, since only a portion of emissions is effectively taxed; this highlights the importance of setting the initial default activity and emissions factors.

Environmental effectiveness. The environmental effectiveness of this approach is only as good as its default emissions rates. If these rates are assigned using current inventories, underestimation of emissions is likely, which would essentially allow firms to pay too low a tax and provide too little incentive to fix leaks. Increasing the defaults by some factor might spark additional monitoring and abatement. This approach faces a problem similar to that of the policies we have already discussed: if emissions from episodic or stochastic emitters cause methane emissions that are missing in the inventory, then emissions may again be underestimated. Of course, a factor could be added on to account for these missing methane emissions. However, the tax with default emissions rates does incentivize improvements in emissions inventories insofar as firms submit revisions for default emissions and activity factors. In addition, operators' incentives to correct default rates would only operate to lower them. If rates are too low, operators have no incentive to correct them.

At the same time, operators have argued that with high default rates, they would incur costs to defend lower rates. The argument is that default rates, say on equipment, apply to every piece of equipment, even those that are

not leaking. And this problem would worsen over the life of the regulation as leaks are fixed.

5. Conclusions

Section 4 highlighted the trade-offs inherent in policies to reduce methane emissions from existing sources. In this section, we summarize how policies tended to balance these trade-offs and end with some concluding observations.

A policy's performance in terms of administrative costs depends importantly on its complexity. For example, policies that involve creating a market—such as a tradable performance standard—bring high administrative costs. Also, policies that involve physically checking individual pieces of equipment, such as technology standards, perform quite poorly simply because of scale.

Economic efficiency policies that allow averaging or trading across subsectors, technologies, regions, and firms tended to do better against our criteria. This trend is consistent with the literature of methane emissions from the natural gas sector, which shows that emissions, and in some cases costs, vary widely along each of these dimensions. In particular, the tradable performance standard seems best optimized for prioritizing economic efficiency, followed by the pollution tax with assumed and updatable default rates—which comes with a slight penalty in the event that initial assumptions about default leakage rates are far off from actual leakage rates.

Focusing on the LDAR program, LDRL performs quite well in terms of economic efficiency because it takes advantage of a tiered approach to identify leaks. That is, a first tier, composed of satellites, planes, or aerial drones, identifies large leaks before dispatching a second tier, ground crews, to locate and repair the source of the leaks. Additional tiering of monitoring technologies could take a variety of forms and could further enhance the cost-effectiveness of abatement. Further research on the ideal number of tiers and the types of technologies to use within those tiers would make a useful contribution.

A policy's performance in terms of environmental effectiveness depends on two factors. The first factor is whether the monitoring technology associated with the policy captures episodic and stochastic emitters in addition to chronic emitters. Many of the policies we have discussed rely on emissions factors, which are unlikely to accurately represent actual emissions because they do not seem to fully capture episodic and stochastic emitters. The class of policies that perform particularly well in this regard is LDAR policies, since they are capable of detecting leaks that originate from chronic, episodic, and stochastic emitters—depending on the specific design of the LDAR program. The second factor is whether the policy incentivizes an improvement in methane inventories. Policies that incentivize firms to monitor and report data about leaks are therefore preferred over policies that merely penalize firms for infractions. Thus our pollution tax with assumed default and updatable leakage rates is advantageous in this regard and deserves careful consideration.

Whichever policy is chosen, the super-emitter problem needs to be addressed with more research and better monitoring technology. Here a tiered approach seems reasonable, where remote sensing (by satellites, airplanes, drones, or some combination thereof) can detect super-emitters and, if supported by technology, monitor compliance. Such a program would provide savings in administrative costs to operators and perhaps the government. The key to environmental improvement is remote-sensing resolution fine enough to pick out a reasonably complete set of super-emitters.

In some ways, LDAR programs represent a middle road between standards and market-based policies. Our analysis demonstrates how the relative effectiveness of LDAR programs depends strongly on the type of detection technology used. Because these technologies and their costs are changing rapidly—thanks to efforts by the private sector, EDF, and the federal government—it is difficult to choose among the LDAR policies: the cost of detecting methane influences many of the criteria we discussed. We therefore emphasize the importance of conducting research for new detection technologies, incorporating that research into ongoing policy discussion, and creating easy on-ramps for their use in the regulatory framework.

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Appendixes

Appendix 1. Details on Literature Review

Table A1 compares EPA's GHGI and GHGRP estimates with academic estimates of methane emissions in the United States. The second, third, and fourth columns describe different aspects of each study. The fifth column summarizes the methane sources to which the authors attribute observed methane emissions. The sixth column reports the ratio of methane emissions estimated by the study to comparable estimates from EPA's GHGI and GHGRP. In most instances, these ratios come directly from the study under discussion. In several instances, however, these ratios are taken from Brandt et al. (2014).

TABLE A1. COMPARING EPA's GREENHOUSE GAS INVENTORY AND REPORTING PROGRAM WITH ACADEMIC ESTIMATES OF METHANE EMISSIONS FROM US NATURAL GAS SECTOR

Study	Geographic coverage	Methodology	Duration of observation	Attributed primary methane sources	Ratio of estimated methane emissions to EPA's GHGI and GHGRP
Wunch et al. (2009)	Regional: South Coast Air Basin (Los Angeles and suburbs)	Ground-based observation using spectrometry	131 days, 2007–8	Natural gas pipelines, landfills, and wastewater treatment	~1 to ~1.25*
Allen et al. (2013)	National	On-site measurement Hi-Flo sampler and infrared cameras, combined with tracer flux methods	May–December 2012	Natural gas production (sites, completion flowbacks, well unloadings, and workovers)	~0.8
Miller et al. (2013)	Regional: South Central	Surface, tower, and aircraft observation with transport model	2007–8	Oil and gas sector	~1.5*
Peischl et al. (2013)	Regional: South Coast Air Basin (Los Angeles and suburbs)	Aircraft observation using spectrometry	May–June 2010	Oil and gas sector and geologic seeps	~2*
Kort et al. (2014)	Regional: Southwest	Satellite observation (SCIAMACHY) with transport model, validated with ground observations	2003–9	Oil, natural gas, and coalbed production and processing	1.8
Turner et al. (2015)	National	Satellite observation (GOSAT) with transport model, validated with ground and tower observations	2006–9	Oil and natural gas sector	1.13–1.74
Lan et al. (2015)	Barnett Shale play	Ground-based spectrometry using inverse modeling	October 2013	5 processing plants	1,737–36,208 (GHGRP)
Lyon et al. (2015)	Barnett Shale play	Bottom-up inventory calculation based on Barnett Shale	October 2013	Oil and gas sector	1.5 (GHGI) 2.7 (GHGRP)

		Coordinated Campaign and other data sources			
Zimmerle et al. (2015)	National	Bottom-up inventory calculation based on Barnett Shale Coordinated Campaign and data from six partner companies and GHGRP	2012	Natural gas transmission and storage facilities (emissions and activity data from 677 and 922 facilities, respectively)	0.75
Lamb et al. (2015)	National	Ground-based observation with Hi-Flo sampler	May–November 2013	Natural gas distribution, including 230 underground pipelines and 229 metering and regulating facilities owned by 13 participating local distribution companies	0.30–0.64
Lavoie et al. (2015)	Barnett Shale play	Airplane observation	October 2013	3 natural gas processing plants	1.1–15.8 (GHGRP)
Lyon et al. (2015)	Barnett Shale play	Airplane observation	October 2013	1 natural gas compressor station	4,190–16,190 (GHGRP)
Marchese et al. (2015)	National	Facility-level measurement using downwind tracer flux measurement and infrared camera, coupled with data sets to determine activity counts	October 2013–April 2014	114 gathering facilities	7.5
Marchese et al. (2015)	National	Facility-level measurement using downwind tracer flux measurement and infrared camera, coupled with data sets to determine activity counts	October 2013–April 2014	12 processing plants	0.59
Allen et al. (2015)	National	Supply flow meters and Hi-Flo samplers		377 pneumatic controllers used in natural gas and oil production sites	1.17** 2.7***

According to Figure 1 of Brandt et al. (2014). In their supplementary materials, Brandt et al. (2014) detail their methodology for translating methane emissions estimates from academic studies so that they can be directly compared with EPA's GHGI.
**In terms of emissions per controller.
***In terms of number of controllers per well.

Table A2 displays estimated leakage ratios by recent academic studies. The second, third, and fourth columns describe different aspects of each study. The fifth column summarizes the methane sources the authors link to observed methane emissions. The sixth column reports the estimated leakage ratio.

For reference, note that combusting natural gas instead of coal provides immediate climatic benefits (i.e., an immediate net decrease in radiative forcing) only if less than 2.7 percent of produced natural gas is emitted before it is used, according to Alvarez et al. (2012) and Hamburg (2013)

TABLE A2. ESTIMATED LEAKAGE RATIOS ACROSS NATURAL GAS SECTOR

Study	Geographic coverage	Methodology	Duration of observation	Attributed primary sources of methane	Leakage ratio
Wunch et al. (2009)	Regional: South Coast Air Basin (Los Angeles and suburbs)	Ground-based observation using spectrometry	131 days, 2007–8	Natural gas pipelines, landfills, and wastewater treatment	1–3%*
Allen et al. (2013)	National	On-site measurement using Hi-Flo sampler and infrared cameras, combined with tracer flux methods	May–December 2012	Natural gas production (sites, completion flowbacks, well unloadings, and workovers)	0.42%
Peischl et al. (2013)	Regional: South Coast Air Basin (Los Angeles and suburbs)	Aircraft observation using spectrometry	May–June 2010	Natural gas production	17%
Peischl et al. (2013)	Regional: South Coast Air Basin (Los Angeles and suburbs)	Aircraft observation using spectrometry	May–June 2010	Natural gas transmission and distribution and geologic seeps	1–2%
Karion et al. (2013)	Local: Uintah Basin	Airplane observation	3 February 2012	Oil and natural gas production and processing	6.2–11.7%
Schneising et al. (2014)	Bakken Shale play	Satellite observation using spectrometry	2006–11	Natural gas production and other potential sources	10% ± 7.3%**
Schneising et al. (2014)	Eagle Ford play	Satellite observation using spectrometry	2006–11	Natural gas production and other potential sources	9.1% ± 6.2%**
Mitchell et al. (2015)	National	Facility-level measurement using downwind tracer (nitrous oxide/acetylene) flux measurement and infrared camera	October 2013–April 2014	114 gathering facilities	0.2%
Mitchell et al. (2015)	National	Facility-level measurement using downwind tracer (nitrous	October 2013–April 2014	16 processing plants	0.08%

		oxide/acetylene) flux measurement and infrared camera			
Lan et al. (2015)	Barnett Shale play	Ground-based spectrometry using inverse modeling	October 2013	34 well pads	7.9% (average), 2.1% (median)
Lyon et al. (2015)	Barnett Shale play	Bottom-up inventory calculation based on Barnett Shale Coordinated Campaign and other data sources	October 2013	Oil and natural gas sector, including production sites, compressor stations, and processing plants	1.0–1.4%
McKain et al. (2015)	Regional: Boston	Ground-based observation with transport model	2012–13	Natural gas transmission, distribution, LNG import and end use	2.7% ± 0.6%
Marchese et al. (2015)	National	Facility-level measurement using downwind tracer flux measurement and infrared camera, coupled with data sets to determine activity counts	October 2013–April 2014	114 gathering facilities	0.33%
Marchese et al. (2015)	National	Facility-level measurement using downwind tracer flux measurement and infrared camera, coupled with data sets to determine activity counts	October 2013–April 2014	16 processing plants	0.1%
Peischl et al. (2015)	Regional: Haynesville, Fayetteville, and Marcellus Shale plays	Aircraft observation and source attribution	June–July 2013	Natural gas production and other minor sources	1.0%
Karion et al. (2015)	Regional: Dallas–Fort Worth Basin	Aircraft observation and source attribution	March–October 2013	Oil and natural gas sector (production through end use)	1.3–1.9%

* In addition to estimates by California government. All observed methane is assumed to be attributable to natural gas pipelines.
** The leakage ratio is defined in terms of energy content as the ratio of emissions increase between 2006–8 and 2009–11 divided by the production growth between these two periods, as observed in each of the plays.

Table A3 lists where and when researchers have observed super-emitters and what they found.

TABLE A3. EVIDENCE OF SUPER-EMITTERS

Study	Geographic coverage	Methodology	Duration of observation	Object of Interest	Distribution of methane emissions
Alvarez et al. (2012)	Local: Fort Worth, Texas	Analysis of data collected by Eastern Research Group via ground observation using Hi-Flo sampler and FLIR infrared camera	—	250 natural gas production sites without compressor stations	10% of well sites account for nearly 70% of estimated emissions
Caulton et al. (2014)	Local: Southwestern Pennsylvania	Airplane observation using Picarro spectrometer	—	7 natural gas production sites, actively drilling	1% of well sites account for 4–30% of estimated emissions
Zavala-Araiza et al. (2015)	Barnett Shale play	Analysis of data from Rella et al. (2015), Lan et al. (2015), and Yacovitch et al. (2015)	—	186 natural gas production sites	15% of production sites contribute 58–80% of estimated emissions
Mitchell et al. (2015)	National	Facility-level measurement using downwind tracer (nitrous oxide/acetylene) flux measurement and infrared camera	October 2013–April 2014	130 gathering facilities	30% of gathering facilities contribute 80% of estimated emissions
Mitchell et al. (2015)	National	Facility-level measurement using downwind tracer (nitrous oxide/acetylene) flux measurement and infrared camera	October 2013–April 2014	16 processing plants	45% of processing facilities contribute 80% of estimated emissions
Rella et al. (2015)	Barnett Shale play	Ground-based observation	October 2013	182 well pads	22% of well pads contribute 80% of estimated emissions
Lyon et al. (2015)	Barnett Shale play	Bottom-up inventory calculation based on Barnett Shale Coordinated	October 2013	Natural gas production sites	0.25% of production sites contribute 11% of estimated emissions from all production

		Campaign and other data sources			sites
Lyon et al. (2015)	Barnett Shale play	Bottom-up inventory calculation based on Barnett Shale Coordinated Campaign and other data sources	October 2013	Gathering and compressing stations	1% of stations contribute 33% of estimated emissions from all stations
Lyon et al. (2015)	Barnett Shale play	Bottom-up inventory calculation based on Barnett Shale Coordinated Campaign and other data sources	October 2013	Processing plants	2% of plants emit 11% of estimated emissions from all plants
Zimmerle et al. (2015)	National	Bottom-up inventory calculation based on Barnett Shale Coordinated Campaign and data from six partner companies and GHGRP	2012	Natural gas transmission and distribution; 13 components, including open-ended lines, valves, vents, and pneumatics; sample size ranges from 47 to 408 for components in given category*	5% of top-emitting components in component category emit 36–75% of emissions for that category
Yacovitch et al. (2015)	Barnett Shale play	Ground-based measurement using spectrometry	Spring and fall 2013	188 methane plumes from oil and gas operations (including well pads, compressing and gathering stations, and some pipelines) and biogenic sources	7.5% of top emitters contribute 60% of total estimated emissions
Subramanian et al. (2015)	National	On-site measurements and tracer flux estimates	Summer and fall 2013	36 compressor stations and 9 compressor stations across 16 states and owned by participating partners	Less than 10% of sites contribute more than 50% of total estimated emissions

See supplementary materials of Zimmerle et al. (2015) and Lyon et al. (2016).

Appendix 2. Methane Policies in Practice

This appendix reviews policies in practice that we did not cover in the main text, including certain voluntary programs and EPA's regulation of volatile organic compounds (VOCs), which provide methane reductions as a cobenefit.

Voluntary Technology-Based and Performance-Based Programs

In addition to EPA's NG STAR, now the Methane Challenge Program, we are aware of at least three other voluntary efforts: United Nations Environment Programme (UNEP), M. J. Bradley & Associates (a consulting firm), and the Center for Responsible Shale Development. Each supports a specific voluntary effort to reduce methane emissions from the natural gas sector. Ironically, these efforts focus on incentivizing participating firms to adopt particular technologies that reduce methane emissions—and thus a very inflexible policy is embedded in a very flexible (i.e., voluntary) program.

UNEP's Climate and Clean Air Coalition's Oil and Gas Methane Partnership

The Oil and Gas Methane Partnership framework of UNEP's Climate and Clean Air Coalition (CCAC) encourages oil and natural gas companies to voluntarily adopt technologies that reduce methane emissions. CCAC launched in 2014 with seven founding companies, guided by the goal of giving firms a way to address methane emissions that could be demonstrated to stakeholders. In contrast to NG STAR, CCAC focuses only on the production sector and strongly emphasizes international companies.

To participate in CCAC, a company must voluntarily complete four steps. First, the company must sign a memorandum of understanding committing to undergo systematic evaluation and management of methane emissions from nine sources identified by CCAC. Second, within six months of joining, the company must develop an implementation plan that outlines sources of methane emissions and includes a strategy for evaluating reduction opportunities. Third, the company must evaluate cost-effective technologies to address uncontrolled sources of methane with "a view toward implementation." Fourth, the company must report progress on surveys, project evaluations, and project implementation in a transparent, credible manner that demonstrates results. The CCAC secretariat, housed at UNEP, subsequently reviews these reports, which are then summarized and publicized.

In return for their participation, companies receive assistance from CCAC's technical partners—including EPA's NG STAR program and EDF—as well as recognition for their ongoing and continued efforts (UNEP 2016).

M. J. & Bradley Associates' Downstream Natural Gas Initiative

M. J. & Bradley Associates' Downstream Natural Gas Initiative is a collaboration among seven natural gas companies to address major technical and regulatory challenges to reducing methane emissions from natural gas distribution systems. The initiative encourages participants to improve quantification of methane emissions, use methane abatement technologies, and identify regulatory elements to enable natural gas distributors to abate methane proactively alongside existing priorities of safety and reliability. In return for their participation, participants receive technical and policy support from M. J. & Bradley Associates.

Center for Sustainable Shale Development

The Center for Sustainable Shale Development is a nonprofit alliance of industry and nongovernmental organizations that sets and achieves performance standards, which are intended to be stricter than federal

and state regulations, for developing shale resources in the Appalachian basin. It has methane emissions performance standards that address flaring, green completions, and storage tank emissions controls.

Direct Regulation of Volatile Organic Compounds

New Source Performance Standards Regulation of VOCs

EPA issued technology and performance standards in 2012 to reduce volatile organic compound emissions at new and modified hydraulically fractured wells. The standards took effect in 2015. The VOC emissions reductions are to be achieved by requiring capture of natural gas that currently escapes into the air and will therefore also lead to reductions in methane emissions (EPA 2015d); these are referred to as "green completions" (Danish 2014). In addition, certain new and modified pneumatic controllers would be required to reduce VOC emissions, providing an estimated 95 percent reduction in these emissions sources.

The NSPS regulation of VOCs clearly represents an indirect approach to reducing methane emissions. This regulation has been criticized for not being comprehensive; it covers only hydraulically fractured gas wells (excluding hydraulically fractured oil wells), a small selection of new types of equipment, and a portion of the natural gas subsectors. In addition, a Clean Air Task Force report contends that directly regulating methane instead of VOCs would lead to more VOC reductions than achieved by this regulation (McCabe et al. 2015). However, EPA likely took this approach because it felt the legal grounds for regulating VOCs were firmer than those for directly regulating methane.

Control Techniques Guidelines for VOCs

Relying on Section 182 of the CAA, EPA plans to develop new control techniques guidelines (CTGs) that would include an analysis of available cost-effective technologies for controlling VOC emissions from covered oil and gas sources (EPA 2015a). States can adopt measures mentioned in the CTGs when writing their state implementation plans (SIPs) in the Ozone Transport Region (the states east of the Mississippi River) and in ozone areas not in attainment with National Air Ambient Quality Standards for ozone. The CAA requires states with "moderate" to "extreme" noncompliance ratings to implement CTGs in their SIPs; states with less severe noncompliance have more discretion (Danish 2014). Under this arrangement, the level of reduction in VOC emissions—and consequently, methane emissions—due to the regulation depends on the level of nonattainment with the ozone standard. EPA set the standard in fall 2016 at 70 parts per billion (ppb), down from 75 ppb. This change pushes 18 additional counties into nonattainment.

Issues with Voluntary Programs

There are at least two concerns regarding voluntary programs. One is additionality: voluntary programs may not cause methane reductions that are additional to existing policies (state or federal) or the business-as-usual operations of participating companies. For instance, many of the technologies encouraged by the NG STAR program involve the capture of methane, which can then be resold; in 2013, participating companies recaptured $200 million in natural gas sales by implementing technologies outlined in their implementation plans (EPA 2015c). If the companies knew about these technologies before participating in a voluntary program, and abatement costs are below revenues recovered by methane capture, a compelling argument can be made that they would have achieved these methane reductions without the program. Moreover, the annual reporting forms that companies must fill out for NG STAR, for example, do not elicit any

information regarding additionality—including policy or economic causes for methane reductions. Without this information, it is difficult to tell what portion of estimated methane reductions (if any) can be attributed to the voluntary program.

A second concern is that no third-party verification of emissions reductions is done at companies participating in NG STAR and CCAC's Oil and Gas Methane Partnership. Instead, EPA and UNEP assume that the technologies reportedly implemented by companies are used and achieve their stated theoretical reductions. No rigorous process verifies the installation of prescribed technologies or their associated emissions reductions—a shortcoming that casts doubt on the overall methane reductions estimated by EPA.