The Economics of Natural Gas Flaring and Methane Emissions in US Shale: An Agenda for Research and Policy

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Introduction

In this paper, we lay out a research and policy agenda around natural gas flaring and methane emissions (F&M). We focus on F&M associated with the extraction of oil and gas (O&G) from US shale plays, which are areas with sedimentary rock formations that contain significant O&G reserves. Few economic studies address F&M, but the topic has become increasingly important in climate policy discussions.

The latest Intergovernmental Panel on Climate Change (IPCC) report estimates that anthropogenic methane emissions are "very likely" to have already caused between 0.3°C and 0.8°C of warming, with a central estimate of 0.5°C (IPCC 2021, figure SPM.2). The IPCC has also concluded with "high confidence" that keeping warming below 1.5°C in any model scenario requires significantly reducing anthropogenic methane emissions (IPCC 2021, chapter 1, box 1.2, 53).[1]

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[1]Interquartile range of about 40–60 percent reductions below 2010 levels required by 2050 (IPCC 2018, figure SPM.3a).

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The O&G industry is the largest anthropogenic source of methane after agriculture and, according to the International Energy Agency (IEA), provides some of the most cost-effective opportunities to abate (reduce) greenhouse gas (GHG) emissions (IEA 2021).

O&G wells produce a mix of hydrocarbons: methane (CH_4), natural gas liquids (NGLs), and crude oil. When producers cannot economically deliver methane and NGLs to market, they may flare (burn) them instead. Some gas is also intentionally vented (released) directly to the atmosphere during normal operations, and some is unintentionally leaked. We refer to natural gas that is intentionally burned as flared gas. Methane emissions can come from incomplete combustion during flaring, intentional venting, or unintentional leaking. We group all three activities under the term "F&M."

Geology determines the mix of hydrocarbons that a well produces, but technology and economics determine what share of natural gas is captured and sold. F&M can occur throughout the natural gas system—from upstream wells, midstream processing and pipelines, or downstream refining and distribution systems. Our analysis focuses exclusively on F&M in the upstream segment, where Alvarez et al. (2018) estimate the majority of methane emissions occur.

Despite advances in measuring emissions, the quantity of F&M is still uncertain. This is a key area for research. We summarize the scientific literature in "Quantifying Emissions." We also discuss what is known about the quantity of F&M in the United States and provide some global context. In "Physical Causes of Flaring," we discuss observable patterns in flaring. Producers are required to report most flaring. Flaring reporting requirements make it easier to quantify aggregate flaring, unlike unreported venting and unintended leaking. Understanding the physical causes of flaring can inform both flaring and methane regulation.

Natural gas is burned off through flaring—essentially, wasted rather than captured—due to a number of regulatory, infrastructure, and market constraints, as well as economic decisions by operators. Recent scientific evidence suggests that the constraints that induce producers to dispose of natural gas through flaring may also drive methane emissions (Lyon et al. 2020). We then turn to the economics of F&M. In "Private Incentives and F&M," we describe how market structures could exacerbate constraints and affect the effectiveness of policy.

F&M impose environmental costs on society through GHG emissions and local air pollution. In "External Costs of F&M," we summarize relevant literature on external costs. We perform a back-of-the-envelope calculation showing that reported US upstream flaring in 2019, a peak year, generated \$1.7–\$3.4 billion in climate costs, about 0.5–1 percent of the value of US O&G production.[2] The most comprehensive estimate available of US upstream methane emissions is from 2015, although O&G production has since increased (Alvarez et al. 2018). Applying a \$1,500/ton social cost of methane (SCM) yields \$16.8 billion in climate costs—an order of magnitude larger than costs from flaring. Thus, policy makers and researchers looking to understand environmental impacts of O&G operations should focus beyond reported flaring.

Finally, we turn to policy in "Policy Options for F&M." The capabilities of measurement technology determine policy options. We discuss how market institutions and emerging monitoring technology lead to new theoretical and applied questions that are relevant beyond F&M.

[2]This estimate excludes unreported methane emissions and downstream emissions.

Industry Overview

The O&G supply chain includes three broad components: upstream, midstream, and downstream. Upstream firms extract hydrocarbons from reservoirs underground. Midstream firms transport extracted hydrocarbons to downstream users. The natural gas midstream includes several services. A network of gathering pipelines transports natural gas to gas processing plants, which separate out heavier hydrocarbons and other impurities. Then, long-haul transmission lines move gas to demand centers. For perspective, the 2019 MapSearch data set of Texas natural gas infrastructure contains 53,000 miles of gathering pipelines, 111 gas processing plants, and 8,300 miles of transmission lines within the Texas Permian Basin. These facilities are owned by 172, 26, and 51 firms, respectively.[3] Finally, downstream firms, such as oil refiners or natural gas distributors, manufacture products from raw hydrocarbons or deliver products to final consumers. Although we focus on upstream F&M, we will provide context on upstream emissions relative to midstream and downstream. Appendix A (appendixes A–D are available online) provides a review of the industry and relevant terminology.

Quantifying Emissions

Quantifying methane emission presents two challenges. The first has to do with comparing methane to other GHG emissions. Methane's 20-year global warming potential (GWP) is around 85 times that of CO_2 (US EPA 2021). Although methane stays in the atmosphere for a shorter time than CO_2—12 years on average compared with CO_2's 100 years—methane's 100-year warming potential is 28–36 times that of CO_2 (US EPA 2022, Annex 6). A more natural measure of methane emissions for economists may be the social cost of carbon and methane (SCC and SCM). These are estimated using integrated assessment models that tally the future economic costs of climate change due to an additional unit of emissions. For 2020, the current federal SCC estimate is $51/metric ton (mt), and the SCM is $1,500/mt (IAWG 2021).

The second challenge is quantifying the physical amount of methane emissions. In this section, we discuss methane measurement in the context of the upstream O&G industry. Multiple quantification methods are available, but none are comprehensive. This leaves uncertainty about the actual quantity of emissions. Measuring methane is an active area of scientific research, and we review the economic implications of key methods and findings.

EPA's Greenhouse Gas Inventory (GHGI) estimate of US methane emissions illustrates the challenge of reporting methane emissions. The GHGI estimates that 2020 US methane emissions were 26 million mt (US EPA 2022, table 2-2). As a party to the United Nations Framework Convention on Climate Change, the United States must report GHG emissions using GWP values from the IPCC Fourth Assessment Report (AR4). The GWP for methane is 25 in that assessment, so the GHGI reports that methane emissions were equivalent to about 650 million mt of CO_2—accounting for 10 percent of US GHG emissions (US EPA 2022, table 2-1). An even greater warming potential of methane has been estimated in more recent

[3]We include active natural gas facilities in the Texas Permian only. MapSearch classifications do not differentiate between transmission pipelines, which move gas between regions, and trunklines, which move gas within the region.

IPCC assessment reports (US EPA 2022, Annex 6). In addition, as we explain later, results from recent scientific publications suggest that the GHGI underestimates methane emissions from the O&G sector.

Emissions Sources

Upstream F&M occurs for several reasons. Intentional venting and flaring can help maintain stability in the pressurized system of pneumatic devices, valves, compressors, and tanks at the production site and throughout the natural gas system. Unintentional leaking may occur due to overpressurization, volatile conditions, or malfunctions (Zavala-Araiza et al. 2017). Some normal production activities also emit methane, including well completions, liquids unloading, and workovers.[4] The largest sources of upstream methane emissions are storage tanks, pneumatic devices, unlit or inefficient flares, separators, and compressors. A large variety of components may emit small- or medium-sized amounts that, when added up, account for a significant share of emissions. Recent studies have measured emissions of individual components. Some have simulated emissions distributions to reconcile these measurements with site-level or regional estimates (Allen et al. 2013; Caulton et al. 2014; Lyon et al. 2016; Gvakharia et al. 2017; Zavala-Araiza et al. 2017; Rutherford et al. 2021; Tyner and Johnson 2021).

Market conditions are also important. Lyon et al. (2020) find that methane emission rates in the Permian Basin fell from 3.4 to 1.5 percent of gas produced in 2020, when oil prices and production dropped during the COVID-19 pandemic. The authors hypothesize that lower system pressures reduced F&M. Studies also document correlation between production and methane emissions both within and across producing regions (Omara et al. 2018; de Gouw et al. 2020; Schneising et al. 2020).

Emissions Data and Distributions

The three main public data sources on F&M are (1) self-reports, (2) satellite data, and (3) bottom-up inventories. The scientific literature has also gathered remote-sensing data from individual site-level surveys (Brandt et al. 2014; Alvarez et al. 2018).

State and federal O&G regulators require that operators report the quantity of gas vented and flared (methane plus NGLs) along with production. However, flaring and venting are usually reported separately,[5] and operators are not required to report all venting and flaring. For example, Texas does not require reporting venting from tank vapors or valves or from flaring and venting associated with drilling and completion.[6] Leaking, even if detected, is not reported.

Satellites are one way to perform top-down measurement of global F&M. The Visible Infrared Imaging Radiometer Suite (VIIRS) satellite instrument has been used to detect the heat signatures of flaring since 2012 (Elvidge et al. 2013, 2016). Beginning in late 2017, the European Space Agency's TROPOspheric Monitoring Instrument (TROPOMI) has provided global measurement of methane concentrations (Hu et al. 2016, 2018). Although these two satellites have been useful for estimating aggregate emissions, it is harder to attribute emissions to

[4] Liquids unloading involves removing liquids trapped in a well. Workovers involve restimulating a well to prolong its life.
[5] New Mexico is an exception.
[6] 16 Tex. Admin. Code §3.32.

individual facilities or firms. More statistical research into the source of satellite-detected emissions has the potential to improve this ability. Regional estimates can also be made with remote sensors mounted on towers, aircraft, or vehicles, but published surveys have limited temporal and spatial scope.[7]

A third source of data on methane emissions at a national level comes from bottom-up inventories. These typically apply fixed emissions factors to estimated inventories of components and activities at production sites. Bottom-up approaches like those in the GHGI are often used by policy makers but come with challenges. Top-down methane emission estimates from satellites and aerial surveys have historically exceeded bottom-up estimates. Recent studies have helped resolve these differences (Zavala-Araiza et al. 2015a; Alvarez et al. 2018; de Gouw et al. 2020; Rutherford et al. 2021). There are two major limitations of bottom-up inventories. First, inventories tend to undercount the number of components at each facility. Second, component emissions factors do not account for the right-tailed distribution of emissions, where a few emitters, components, or temporary events are responsible for most of the emissions. Two changes have helped align bottom-up and top-down estimates: (1) augmenting inventories, satellites, and aerial surveys with facility-scale measurements using ground-based remote sensing and (2) modeling the right-tailed distribution from individual components (Rutherford et al. 2021).

Significant quantities of emissions come from a small number of intermittent sources that are large in absolute terms, sometimes called "superemitters" (Lyon et al. 2015; Robertson et al. 2017; Zavala-Araiza et al. 2017; Tyner and Johnson 2020). Superemitters can also be defined in relative terms. The right-tailed distribution of emissions is present in both large components (e.g., storage tanks) and small components (e.g., valves; Tyner and Johnson 2020). Zavala-Araiza et al. (2015b) argue that superemitters should be defined by their proportional emissions rate rather than their absolute magnitude. They calculate that more than half of emissions are from medium-scale production sites.

Even if a small number of superemitters account for the majority of emissions, there might be substantial costs to reduce these emissions. One might like to imagine using overflights and site-level surveys to find superemitters and fix them at low cost. However, emissions from superemitters can be characterized by uncertainty and variability over time and space (Zavala-Araiza et al. 2017). If surveys are not made with large enough samples or frequently enough, they may not detect many superemitters. Because remote-sensing technologies have limitations such as minimum and maximum detection thresholds, they are not comprehensive. This means that relying on one technology can distort measured emissions; a portfolio of technologies may be most effective (Harriss et al. 2015; Fox et al. 2019; Tyner and Johnson 2020).

Like methane emissions, flaring exhibits a right-skewed distribution. Figure A10 shows these distributions for both the Bakken and the subregions of the Texas Permian Basin. In the Bakken, approximately 75 percent of the reported flaring comes from about 12.5 percent of wells. The distribution is even more skewed in the Permian, and this pattern is persistent across years (2016–2020).

More rigorous empirical studies, with attention to causal identification, could determine systemic causes of superemitting events. These could help policy makers understand the causal

[7]See Brandt, Heath, and Cooley (2016) for a survey.

links among market conditions, capacity constraints, and F&M. The fact that satellite measurements are imprecise at finer spatial and temporal scales makes it challenging to attribute satellite-detected F&M to individual firms. Finally, work is needed to statistically integrate multiscale measurements. Recent work in machine learning and machine vision may be one way to estimate leak probabilities and prioritize sites for inspection (Wang et al. 2020).

Estimates of US F&M

Shale gas production and US flaring have increased over the past two decades. The majority of US flaring currently takes place in two oil-focused shale plays: the Bakken Shale and the Permian Basin.[8] Figure 1 shows the relationship between reported flaring and oil production in these areas. Using data compiled from state regulators, the US Energy Information Administration (EIA) estimates that US upstream producers flared 538 billion cubic feet (bcf) of natural gas in 2019, equivalent to approximately 1.3 percent of US gas production. Using satellite data from VIIRS, the World Bank (2019) estimates that the entire US gas supply chain flared or vented 611 bcf in 2019. The same data show that, over the period 2015–2019, the United States flared the third-highest volume of any country, accounting for 8.4 percent of global flaring.[9] The United States was the largest global producer of natural gas over this period, producing 22 percent of dry natural gas globally.[10] If US gas flared in 2019 was used to generate electricity, it could have powered 7–8 million households for a year.[11]

The IEA estimates that the US energy industry has been the second-highest global methane emitter behind Russia for several years (IEA 2021).[12] Synthesizing the scientific literature and using several measurement methods, Alvarez et al. (2018) estimate that, throughout the entire natural gas system, 2.3 percent of 2015 US gas production was emitted as methane. The authors attribute 60 percent of methane emissions to the upstream sector and another 20 percent to gas-gathering systems. A more recent bottom-up study that incorporates uncertainty in component-level emissions generally corroborates these findings (Rutherford et al. 2021). Although neither study extensively surveyed the Permian Basin, Schneising et al. (2020) and Zhang et al. (2020) did so in 2018 and 2019. These newer studies estimate that 3.7 percent of Permian methane produced was emitted during production, gathering, or processing.

Accounting for F&M can be important when assessing climate trade-offs between fuel sources in electricity generation. For example, coal emits more than twice the CO_2 of natural gas when combusted to generate a unit of electricity. However, this does not take into account F&M along the entire supply chain.[13] Alvarez et al. (2012) estimate that coal and natural gas

[8]See map in figure 6 for US shale plays.

[9]EIA estimates include upstream venting and flaring as reported by operators. VIIRS-based estimates include midstream and downstream flaring but exclude venting and other methane emissions (World Bank 2019).

[10]From US EIA International Dry Natural Gas Production by Country.

[11]Calculation based on a heat rate of 7,000 BTU/kWh. According to EIA, average US residential households used 10,968 kWh in 2018.

[12]Although IEA data have historically been based on bottom-up inventory methods submitted by member countries, the most recent year incorporates global satellite data into country-level estimates.

[13]According to EIA, in 2021, 0.97 and 2.26 pounds of CO_2 were emitted per kilowatt-hour of electricity generated from natural gas and coal, respectively, in the United States. Source: EIA website. Frequently Asked

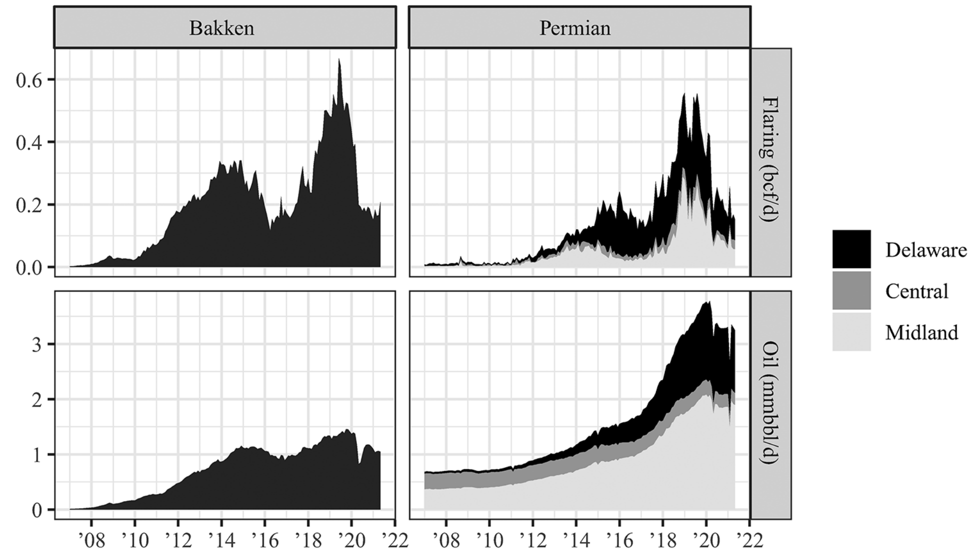

Figure 1 Flaring, venting, and oil production in the Bakken and Permian. The top panels use data reporting flaring and venting together. The Delaware, Central, and Midland are basins within the Permian.

power plants would have equivalent climate impacts at a 3.2 percent life-cycle methane leakage rate from the natural gas system.[14]

Physical Causes of Flaring

In this section, we describe the empirical behavior of reported flaring. We then discuss the related market conditions and constraints. We use regulatory data from North Dakota on the Bakken shale and from Texas on the three main areas of the Permian: the Delaware, Central, and Midland basins.[15] We use the term "reported flaring" to refer to flaring plus some venting. These are reported as a single number in monthly production reports to state regulators. We assume that flaring accounts for most self-reported flared and vented volumes, using the same assumption as in Lade and Rudik (2020). We focus on reported flaring for three reasons. First, there are no comprehensive data on methane emissions at the well level. Second, because inefficient and unlit flares emit methane, flaring reductions are relevant for methane abatement. Third, venting and leaking may be exacerbated by the same conditions that lead to flaring (Lyon et al. 2020).

Flaring has sometimes been cast as the result of physical constraints imposed on producers. That characterization is incomplete. Flaring is the result of producers' economic decisions given physical constraints. There are at least two economic decisions at play. First, producers decide when and where to extract oil. Second, they decide whether to flare or capture

Questions (FAQs). *How much carbon dioxide is produced per kilowatt-hour of US electricity generation?* https://www.eia.gov/tools/faqs/faq.php?id=74&t=11.

[14]Break-even estimates vary. Howarth, Santoro, and Ingraffea (2011) argue for between 2 and 3 percent, whereas Farquharson et al. (2017) argue for closer to 4 percent.

[15]See appendix B for a description of data sources.

the associated gas. Producers can reduce flaring by changing either of these two decisions: they can delay extraction, or they can invest in infrastructure and services to capture the gas.

Delivering gas to market requires a suite of infrastructure and services beyond what is required for oil. To begin with, the site must have equipment on-site to capture the gas and must be connected to local gathering lines. Then, the gas needs to be transported to processing plants to strip out heavier hydrocarbons, followed by long-haul transmission to carry the gas to market.

Data on Bakken and Permian flaring suggest that congestion in the steps after gathering—not absence of connection to gathering—has been the primary physical cause of flaring for several years. Moreover, there are multiple points in the natural gas supply chain that appear to experience congestion.

Flaring comes from two groups of locations: those that both sell *and* flare gas in the same quarterly time period and those that flare all of the gas produced in a quarter.[16] Of the locations that flare all gas, some have always flared everything; others have previously sold gas. Locations that have previously sold gas are likely connected to gathering infrastructure. Those that have never sold gas are likely not connected.[17]

Figure 2 shows that locations that flare most or all gas contribute less than half of all flaring for most quarters. The majority of flaring in the first half of 2021 comes from locations that also sell at least 25 percent of their gas. By mid-2021, flaring by unconnected locations made up less than one-quarter of flaring in the Bakken or Permian, even though unconnected locations accounted for the majority of flaring during early development of the Bakken and the Delaware.[18]

The fact that most flaring comes from connected locations that sell their gas suggests that intermittent congestion, not connection delays, explains most flaring. When gas production exceeds midstream capacity, some oil wells must flare associated gas to keep producing oil. Additional evidence supports this hypothesis. As shown in figure A11, the probability of a location flaring *some* gas (versus all or none) has increased over time. This is consistent with a 2019 Federal Reserve survey of producers: 49 percent of respondents cited capacity constraints in gathering and processing as a reason for flaring (Federal Reserve Bank of Dallas 2019).

Congestion in midstream infrastructure can happen downstream of gathering. Before natural gas enters a transmission pipeline, it must be separated from heavier hydrocarbons at a gas processing plant. Insufficient processing capacity, like insufficient gathering capacity, has likely caused some flaring, especially in the Bakken (DOE 2014; Blundell and Kokoza 2022). Figure 3 plots gas processing capacity versus gas production in the Bakken. Although processing has increased with production, production has exceeded processing capacity several times. Because production and processing take place in different locations, spare capacity

[16] In North Dakota, firms report well-level flaring. In Texas, firms report flaring for each gas well and each oil lease. A lease can involve multiple wells. See appendix B for additional discussion.

[17] In Texas, we are unable to identify whether the individual wells on a lease are physically connected to gathering—just whether gas produced on a lease has been sold.

[18] Lade and Rudik (2020) cast Bakken flaring as an issue of connecting wells to gathering, presumably because their analysis is restricted to 2007–2016, when connection to gathering was a more important driver of flaring.

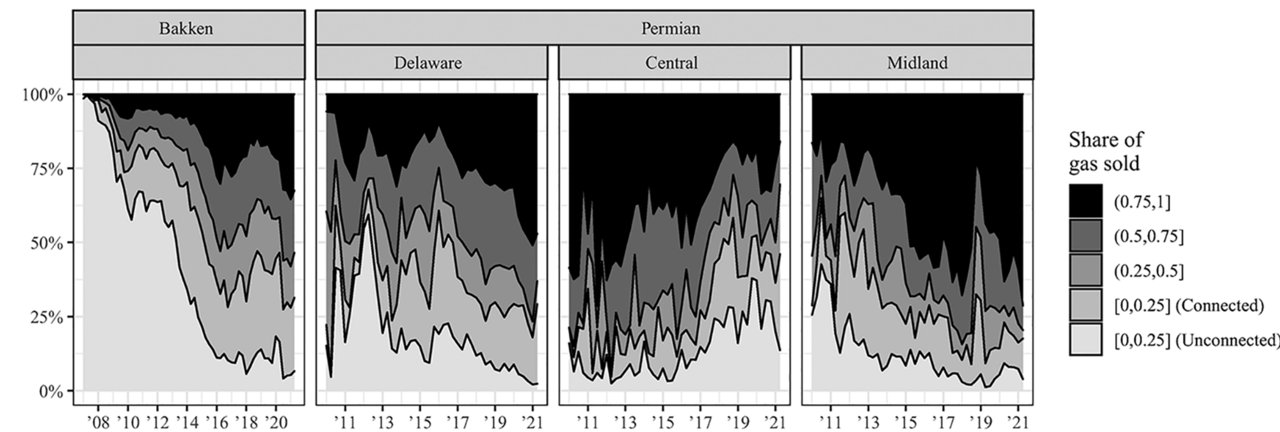

Figure 2 Share of total gas flared by share of gas location sales that quarter.

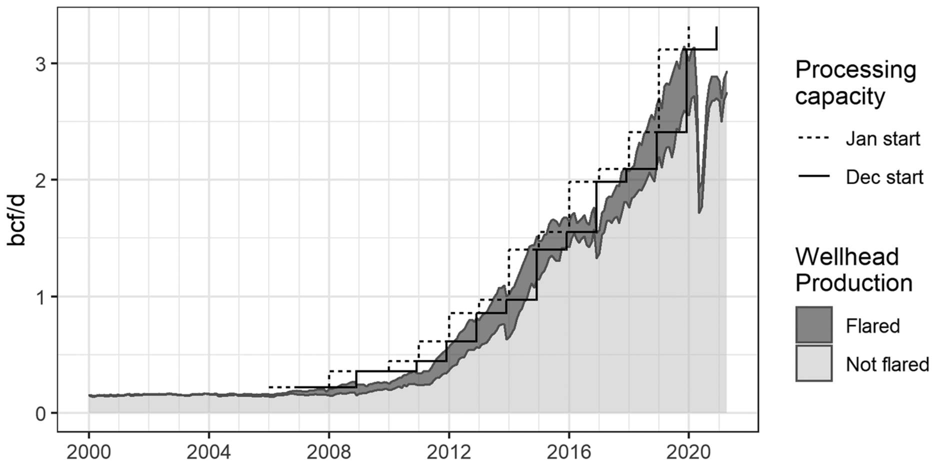

Figure 3 North Dakota gas processing capacity barely kept pace with North Dakota gas production. Plant capacity assumes capacity is online in either January or December of year indicated. Data are from NDIC and NDPA.

in one area may not be accessible to constrained producers in another. This means that aggregate utilization rates can understate congestion at specific locations.

Long-haul transmission pipelines carry gas from processing plants to market. We present descriptive evidence consistent with transmission constraints causing flaring, particularly in the Midland region of the Permian. The bottom panel of figure 4 shows the difference between the nationally representative spot price for natural gas (Henry Hub) and the spot price in the Midland gas hub (Waha). The difference reflects the scarcity premium (rent) associated with transmission out of the Permian. Scarcity rents rose so much in 2019 and 2020 that Waha gas prices were negative. Although persistent scarcity rents incentivize pipeline investment

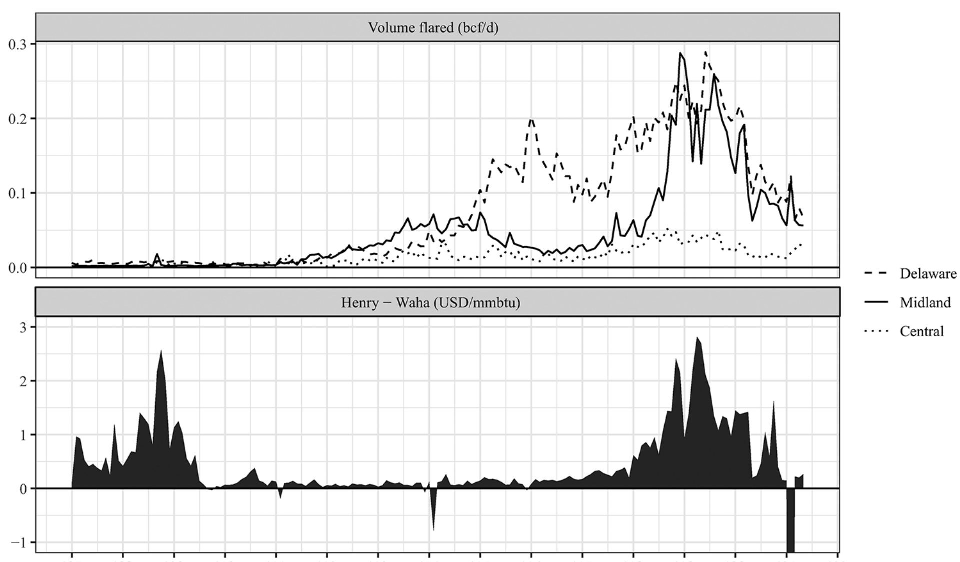

Figure 4 Flaring in the Permian and natural gas basis differentials.

(Oliver, Mason, and Finnoff 2014; Agerton and Upton 2019), building pipelines takes time. The top panel of figure 4 shows Permian flaring over time by region. There is a clear correlation between transmission scarcity rents and Midland flaring; both appear to rise to balance demand and supply for transmission. In contrast, Delaware flaring started increasing in 2015, well before the emergence of a Waha–Henry Hub differential.

Private Incentives and F&M

Some of the physical constraints highlighted in "Physical Causes of Flaring" may be transitory, but others may persist absent market or policy changes. In this section, we describe reasons why gas production might exceed infrastructure capacity and then be flared.

Natural gas has economic value. Therefore, profit-maximizing firms will dispose of gas in a flare only if the cost of not flaring is greater than the market value of the gas. The costs of not flaring may include the missed profits (opportunity cost) of delaying oil production, as well as the costs of installing new equipment or gathering, processing, and transporting the gas. Industry think tank reports suggest that much F&M could be abated at negative marginal cost; that is, the costs of reducing the amount of F&M could be less than the profits that are missed by failing to capture more natural gas (IEA 2021; Rystad Energy 2021). However, producers' behavior in practice suggests that they fail to reduce F&M because this would be unprofitable. Difficulties in detecting methane emissions and opportunity costs to prevent F&M could help explain this apparent inconsistency.

Some flaring likely makes economic sense when developing a new area. In a new area, producers face uncertainty about the area's geologic and economic potential and how much infrastructure they will need. It can be valuable to flare associated gas, delay midstream investment, and maintain the option to build infrastructure later with more information. In addition, production from new shale wells declines quickly. It may not make economic sense to build capacity sufficient to handle peak initial production if production declines rapidly. Instead, it might be more profitable to flare a share of the gas initially. Both uncertainty and rapid production declines are acute in the short run. As a play matures and production stabilizes, these economic rationales for flaring should dissipate.

Midstream companies generally recover their fixed investment costs through variable charges on the volume of gas shipped. As with pricing in utilities, this presents a tension between collecting enough revenue and pricing services efficiently so that they reflect the cost of each additional unit, or marginal cost (Braeutigam 1989; Borenstein 2016). Two observations suggest that midstream prices might not reflect the marginal cost of midstream services. First, 45 percent of respondents to a Federal Reserve Bank of Dallas (2019) survey cited excessive fees in gathering and processing capacity as causes of flaring. Second, wellhead gas prices reported by Permian producers for tax purposes exhibit large variation around national benchmarks, even within a small spatial area.[19] In contrast, wellhead oil prices display little dispersion; they are tightly clustered around the national benchmark (see figure A12). Although some of the variation in wellhead gas prices is probably due to differences in composition of the gas, some could also be due to variation in the price of midstream services.

[19] These data are collected by Enverus from the Texas Comptroller of Public Accounts and merged with Enverus production data derived from the Texas Railroad Commission.

There are two kinds of long-haul natural gas transmission lines: interstate and intrastate. The Federal Energy Regulatory Commission regulates interstate pipelines and transmission rates to ensure that pipeline owners receive enough revenue to cover the cost of service and a reasonable rate of return but do not earn monopoly rents (a premium that reflects the lack of competition).[20] A firm regulated under a standard cost-of-service framework maximizes profits differently from a firm in a competitive (nonmonopoly) market. Averch and Johnson (1962) predict that if the rate of return on the firm's capital investment is less than the cost of capital, the firm will exit the market. In the context of F&M, if the regulator sets the rate of return for transmission too low, midstream firms will not build enough capacity, and producers will flare production in excess of capacity. If the rate of return allowed by the regulator is greater than the cost of capital, transmission owners have an incentive to overcapitalize and possibly overbuild capacity.

As with transmission, gathering infrastructure requires up-front, fixed investments, and gathering services are usually priced based on volume. Unlike transmission, however, gathering agreements are private contracts. To reduce the risk to the midstream firm of hold-up—when a producer ships (or threatens to ship) gas with a competitor—midstream firms often require an acreage dedication. This is a long-term commitment by the producer to ship all gas produced in an area through a midstream firm's gathering system. Despite acreage dedications, midstream companies still face uncertainty about the quantity of gathering services that producers will demand. In the event of a downturn in hydrocarbon prices, lower production and demand for gathering can lead to a revenue shortfall.[21] Consequently, risk-averse midstream firms may raise prices above their expected long-run average cost to ensure that they can recoup their investment. Long-term contracts may help reduce risk for gas processors, but the lumpiness (large fixed costs) of processing investment and the volatility of prices can lead to a mismatch between natural gas production and infrastructure capacity, especially in areas with new production growth.

Flaring, Bargaining, and Competition

Differences in location can limit competition between gathering companies at a specific location. Congestion can exacerbate this, creating isolated submarkets, as is the case in electricity markets (Borenstein, Bushnell, and Stoft 2000). Because gathering prices are market based, limited competition may enable midstream firms to mark up prices. The option to flare serves as an additional source of midstream competition; should negotiations with a midstream provider break down, producers can flare instead of curtailing production. This option may reduce midstream firms' bargaining power.

A recent dispute in Texas between producer EXCO and midstream firm Williams illustrates how the option to flare can limit midstream pricing power (RRC 2019). The dispute centered on whether the regulator would permit EXCO to flare, even though EXCO's wells were physically connected to Williams's infrastructure. Williams argued that allowing EXCO to flare would violate flaring regulations. It asked that EXCO be required to stop flaring and

[20] Appendix A provides additional discussion of midstream market structure.
[21] Long-term take-or-pay contracts (which have a minimum volume commitment) can ameliorate this issue but do not appear to be used as much for gathering and processing.

instead use its oil profits to pay for gas-gathering services. Williams priced gathering at \$198 million, more than four times the market value of the gas—\$45 million. A competitor to Williams would be unlikely to build alternative gathering infrastructure, because Williams's infrastructure was a sunk cost, and Williams could undercut any new entrant. In its decision, the Texas Railroad Commission framed Williams's suit as an attempt to use flaring regulations to gain leverage in a commercial dispute and preserved EXCO's option to flare (RRC 2019, 22).

Frictions in the contracting process and midstream market power can, in theory, lead to inefficiently low gas-capture rates and excess flaring. The extent to which these factors matter in practice is an open question for economic research. As suggested by the EXCO-Williams dispute, midstream market structure and regulation could interact with F&M in important ways.

External Costs of F&M

F&M generate two types of pollution: GHGs and local air pollutants. Quantifying the external health and environmental costs of pollution from F&M is a key question for researchers and policy makers.

Producers can reduce F&M by capturing gas. The effect of capturing the gas on external costs depends on the alternative use of the gas, such as power generation or residential heating. These alternative uses are unlikely to emit equivalent GHGs to F&M for a variety of reasons. For example, gas combustion for power generation is efficient relative to upstream flaring.[22]

As discussed earlier, the climate costs of 1 ton of methane are larger than those of CO_2. This holds true for NGLs: the 100-year GWP of the NGLs butane, ethane, and propane are 7–10 times larger than CO_2 (Hodnebrog, Dalsøren, and Myhre 2018). Emitting these hydrocarbons to the atmosphere imposes higher climate costs than combusting them, whether combustion is through flaring or another productive use.

Even if flaring reductions increase natural gas consumption one-for-one, the fact that flares are not fully efficient suggests that reducing flaring will have net climate benefits. Environmental conditions can reduce flare efficiency (Strosher 2000; Leahey, Preston, and Strosher 2001; Gvakharia et al. 2017), and flares can fail to light. Inefficient and unlit flares release hydrocarbons directly into the atmosphere. An aerial survey in the Permian by the Environmental Defense Fund (EDF) found that more than 10 percent of flares had incomplete combustion. EDF estimates that, on average, flares vent 7 percent of their gas (EDF 2020). This is higher than the 2 percent estimate used in government GHG inventories (US EPA 1996). Much of the flared gas associated with oil production contains NGLs, which generate more CO_2 in combustion than methane does. NGLs are petrochemical feedstocks and could be converted into plastics and other materials instead of being flared or vented. Flaring can also release black carbon, itself a contributor to climate change (Johnson and Kostiuk 2002; Stohl et al. 2013). As discussed in "Quantifying Emissions," recent measurements of US upstream methane emissions

[22] In reality, this is more nuanced, because there are several margins of adjustment. For instance, some wells might not be drilled, reducing O&G production. Upward pressure on prices would reduce consumption. On the other hand, if F&M reductions increase gas supply as firms sell gas instead of flaring it, this could theoretically reduce gas prices and affect power-dispatch decisions. Evaluating these effects is beyond the scope of this discussion.

Table 1 Climate costs from flaring ($/mcf)

Flare efficiency (%)	Bakken mix ($)	Pure methane ($)
100	5.00	2.70
98	5.38	3.23
93	6.31	4.54
0	23.76	28.89

Note: See appendix D for calculations.

tend to be limited to a particular time and place, so it is difficult to compare them or form precise annual estimates of the associated climate costs. Nevertheless, we believe it is important to communicate the general scale of these damages. Quantifying a more comprehensive external cost of US F&M is an important topic for future (likely multidisciplinary) research.

We first address the climate costs of reported flaring and venting. Table 1 shows how NGL content and flare efficiency affect the climate cost of flaring, a point made by Kleinberg (2019). Using the federal SCC and SCM, we calculate that flaring pure methane at the 98 percent efficiency assumed by EPA generates climate costs of $3.23/mcf (see appendix D for details). This is greater than the average spot price of US natural gas in 2020, which was $2.03/mcf. Because of the NGLs present, flaring the Bakken-associated gas mixture analyzed in Brandt et al. (2016) results in higher climate costs than flaring pure methane. Flaring the Bakken gas mixture at 93 percent efficiency—the average efficiency estimated by EDF (2020) in the Permian—results in higher climate costs of $6.31/mcf.

Using these marginal climate-cost estimates as lower and upper bounds, we calculate that reported US flaring and venting generated between $0.9 and $1.8 billion in climate costs in 2015. This figure rises to between $1.7 and $3.4 billion in climate costs in 2019, or about 0.5–1 percent of the value of US O&G production that year.[23] These calculations exclude unreported venting and leaking as well as downstream emissions, and they assume that all of the reported flaring and venting was, in fact, flaring. We note that reported flaring and venting fell in 2020.

We next address methane. Alvarez et al. (2018) estimate that the O&G sector emitted approximately 11 million tons of methane in 2015. Applying the latest federal SCM of $1,500/ton yields climate costs of $16.8 billion. This is an order of magnitude larger than our estimate of the climate costs of reported 2015 flaring. Updated methane estimates comparable to Alvarez et al. (2018) are not currently available. However, 2019 emissions were likely to have been higher than 2015 emissions. First, US O&G production increased by 30 percent and 24 percent, respectively, from 2015 to 2019. Second, the Permian produced a larger share of O&G in 2019 relative to 2015. Zhang et al. (2020) and Schneising et al. (2020) estimate that methane emission rates in the Permian Basin during 2018–2019 were approximately 60 percent higher than the national estimate in Alvarez et al. (2018).

[23]To compute the value of O&G production, we use EIA estimates for monthly total US field production of crude oil and US Natural Gas Gross Withdrawals. We multiply these by the monthly average WTI spot price and Henry Hub spot price. The value of 2015 US oil production was $182 billion in 2020 US$ and gas production was $94 billion. The value of O&G production in 2019 rises to $257 billion and $106 billion.

Flaring, venting, or leaking associated gas also emits EPA-designated criteria pollutants such as nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter, and volatile organic compounds (Buzcu-Guven and Harriss 2012; US EPA 2018, 2019). Actual emissions of each pollutant depend on many localized factors, and existing studies on flaring and emissions use relatively small samples (Strosher 2000; Kostiuk, Johnson, and Thomas 2004; Fawole et al. 2019). Blundell and Kokoza (2022) empirically estimate the causal impacts of Bakken flaring on respiratory health. Although flaring has caused increased hospital visits associated with respiratory ailments, the low population density of North Dakota has limited the scale of external health costs. More work can be done to construct inventories of local air pollutants for major producing basins. As Blundell and Kokoza (2022) find, the external costs of emissions depend on localized health and ecosystem impacts.

Quantifying and valuing F&M externalities remains a policy-relevant research frontier. Uncertainty around the quantity of emissions will hopefully improve as measurement technology advances. Flare composition and efficiency varies across wells, and both factors affect climate costs. Potential health impacts from F&M depend on the composition of flared gas, as well as weather conditions and proximity to population centers. Finally, the benefits of F&M abatement policies depend on the external costs of the alternative use of the gas. The external cost of the alternative could be zero if the gas is left in the ground. If the gas is captured instead, it could include emissions during transportation and consumption.

Policy Options for F&M

We now review current policies and discuss an agenda for F&M policy research. We direct the interested reader to Rabe, Kaliban, and Englehart (2020) for a detailed review of state-level F&M policies and to the Department of Energy (DOE 2019) for a review of state and federal flaring policies.

Current F&M Policies

Texas and North Dakota require firms to obtain flaring permits and report most flared volumes. Although permits in Texas specify how much a well is allowed to flare, there are no statutory limits on upstream flaring. Producers are also allowed to vent for 24 hours at a time during specified events such as liquids unloading or upset conditions (i.e., malfunctions or failures in certain equipment or processes that disrupt the flow of oil or gas). They are not required to report venting from exempt categories such as drilling, completion, or tank releases.[24]

The North Dakota Industrial Commission (NDIC) implemented new flaring and venting regulations in 2014. NDIC Order 24665 established annual gas-capture targets as a percentage of gas production (NDIC 2014). Targets were to increase each year until 2020, when they would reach 91 percent. Operators that did not meet targets would be required to curtail production. The order allowed the first well in a Bakken spacing unit to flare unlimited quantities. Subsequent infill wells are allowed to flare unlimited quantities for 90 days, at which point they become subject to gas-capture targets. The NDIC relaxed flaring regulations once in 2015 and twice in 2018 (NDIC 2015, 2018, 2020). We estimate that, during 2019, Bakken wells

[24] 16 Tex. Admin. Code §3.32.

captured 81 percent of their gas and Permian oil leases captured 95 percent of their gas (see table 3 in appendix C).

Both Texas and North Dakota impose severance taxes on oil and natural gas production. However, Texas exempts associated gas volumes that are flared upstream (Texas Comptroller 2021). North Dakota has a similar exemption but only for the first year of a well's production (ND House Bill 1134; Legislative Assembly of North Dakota 2013). When gas flared upstream is exempted from severance taxes, this lowers the opportunity cost of flaring relative to capturing the gas. One policy consideration would be to equalize the tax treatment of flared versus captured gas.

Most attempts to regulate methane emissions have focused on command-and-control policies (as opposed to market-based incentives) such as Leak Detection and Repair (LDAR) or technology standards. At a federal level, EPA developed a rule in 2016 with prescriptive LDAR and emissions-control technology standards.[25] However, the rule was never fully implemented before it was challenged in court and replaced with a less stringent policy.[26] EPA proposed an updated, more stringent rule in November 2021.[27] At the time of this writing, the rule is undergoing public comment. Colorado and Pennsylvania also have specific upstream and midstream requirements for LDAR and methane emissions reporting. These LDAR standards focus on leaking, but not flaring, and do not provide continuous monitoring or emissions quantification.

Future Policy Options

Marks (2022) estimates that initial methane abatement would generate net social benefits, but costs increase steeply after about two-thirds of abated emissions. He estimates that a \$3.17/mcf methane tax would decrease emissions by 60 percent, achieving \$1.8 billion in annually avoided climate costs. Taxing methane at \$28/mcf (the SCM) would reduce emissions by almost 75 percent (Marks 2022, table 3). Both Lade and Rudik (2020) and Johnson and Coderre (2012) similarly find that moderate flaring taxes could reduce flaring significantly.

Alternative market-based instruments might also be considered. For instance, portfolio standards, rather than regulating every element of a firm's operations, require the firm to achieve an overall environmental target; examples include automobiles, motor fuels, and electricity markets (Austin and Dinan 2005; Holland, Hughes, and Knittel 2009; Upton and Snyder 2017). North Dakota uses a portfolio standard for flaring, in the sense that a producer must meet environmental standards across its entire portfolio of wells rather than at each individual well. Markets for "responsibly sourced" or "green" gas are also developing (Krupnick and Munnings 2020). These markets allow producers with environmentally responsible practices to differentiate their gas with the goal of selling their green gas for a premium.

Environmental economics theory shows that efficient policies will account for differences in the external costs of "bads," such as F&M. In theory, the stringency of efficient F&M policies would even vary by location and gas composition if the external costs also vary. However, in practice, F&M policies will need to make trade-offs among simplicity, monitoring costs, and efficiency. These trade-offs can be stark. For example, flaring is easier to monitor than methane

[25] 40 CFR 60 OOOOa.
[26] 85 FR 57018, 85 FR 57398.
[27] 86 FR 63110.

and could be a target of stringent regulations. However, if venting is a substitute for flaring, then stringent flaring limits could lead to more venting. Absent curbs on harder-to-monitor methane, this might limit or even reverse the climate benefits of a flaring policy. Calel and Mahdavi (2020) raise this concern at an international level. Another example is the trade-off between taxing methane using inventory-based estimates versus measured emissions. Inventory-based taxes incentivize firms to optimize inventories of emission sources, not emissions themselves. Directly targeting reductions in measured emissions may lead to lower abatement costs but higher monitoring costs. Inventory-based policies become less efficient when emissions factors differ from actual average emissions, as they currently do (Alvarez et al. 2018; Rutherford et al. 2021).

Several features of F&M lend themselves to considering policies such as targeted inspections, alongside specific requirements or technology standards. Monitoring F&M and attributing them to specific producers pose significant challenges for emissions pricing, whereas a few salient component types (tanks, flares, pneumatic devices) are responsible for a large share of emissions (Rutherford et al. 2021). Engineering simulations suggest that finding and repairing many of these sources is cost-effective for producers, even in the absence of regulatory requirements; however, these simulations produce considerable variation in costs and benefits across sites (Kemp, Ravikumar, and Brandt 2016).

Monitoring and Measurement

As highlighted in "Quantifying Emissions," measurement of F&M is challenging. Firms currently self-report flaring to regulators. Self-reporting can economize on auditing expenses and reduce the firm's risk by replacing large, uncertain fines with smaller, certain fines when violations are reported (Kaplow and Shavell 1994). However, self-reporting also enables mismeasurement and misreporting. The accuracy of self-reports can depend on the enforcement costs of auditing and administering fines, policy stringency, and monitoring-technology accuracy (Malik 1993). Furthermore, leaked volumes often are either not known or not reported.

Remote sensing may be able to help detect misreporting and scale up the process of monitoring each firm's F&M. However, each remote-sensing technology has its own temporal and spatial limitations and detection thresholds (National Academies of Sciences, Engineering, and Medicine 2018; Fox et al. 2019). For example, handheld cameras have lower detection limits, which enable finding many small leaks that may be large in aggregate, but their upper detection limits miss superemitters. Satellites with daily global coverage become more accurate when aggregated, but atmospheric conditions and limited spatial resolution prevent them from identifying individual emitters—particularly when wells from multiple operators are close together.[28]

Accommodating limitations in measurement requires new research. Estimating localized emissions from coarse spatial and temporal measurements will require advances in statistical methods, as will integrating measurements from multiple technologies. Incorporating noisy emission measurements into the design and enforcement of F&M policies will require advances in economic theory.

[28]The spatial resolution of VIIRS is approximately 0.75 km^2 (Elvidge et al. 2013). The resolution of TROPOMI is 3.5 by 7 km (Hu et al. 2018). Both are large enough to cover multiple producing locations.

The economic literature on nonpoint source (NPS) pollution may contain lessons on how to integrate remote-sensing technology into policy. NPS pollution comes from many small sources, such as vehicles and farms, instead of a few large sources that can be easily monitored, such as power plants. The NPS literature studies regulatory mechanisms when it is costly to monitor pollution and determine its source (Xepapadeas 2011; Kotchen and Segerson 2020). NPS mechanisms for F&M could involve taxing observable production inputs or the outputs produced; setting taxes based on regional ambient emissions (emissions that are detectable in the air near a source, rather than observed directly at the source) measured through remote sensing; or hybrid schemes with differential fees based on the precision of the remote-sensing or leak-detection technology in use. The precision and accuracy with which firms can be linked to remotely sensed emissions is an applied question. An F&M NPS mechanism would depend on the technical capabilities of sensors, the spatial and temporal distribution of firms and emissions, and the development of statistical and machine-learning techniques to quantify emissions.

Conclusion

F&M are significant, linked environmental-policy issues for US shale O&G operations and the O&G value chain more broadly. In this article, we provide an interdisciplinary literature review and marshal granular data to identify constraints in the O&G supply chain to explain upstream F&M. Our empirical observations suggest that constraints at multiple points in the natural gas supply chain can cause emissions from upstream operations. Our back-of-the-envelope calculations suggest that the climate cost of upstream methane emissions is an order of magnitude larger than the climate cost of upstream flaring alone. Using the IAWG (2021) SCC and SCM for 2020, we calculate that reported 2015 flaring imposed climate costs of \$0.9–\$1.8 billion based on EIA data, and US upstream methane emissions imposed a cost of \$16.8 billion that year based on the emission estimates in Alvarez et al. (2018).

We highlight several areas where economists can contribute to F&M research. First, causal inference methods can help identify why F&M occurs and evaluate F&M policies. Second, interdisciplinary research can improve understanding of both the external cost of F&M and the abatement cost. Third, economic research can help inform the effectiveness and efficiency of proposed policies, particularly under imperfect monitoring. Researchers should be aware of how the existing market structures in the O&G industry, such as contracting for midstream services, affect F&M and potentially interact with policy in unexpected ways. Similarly, just as economists are attuned to issues of economic structure and uncertainty, they should also be aware of the complex engineering systems at work and the scientific uncertainties around the quantities, costs, and physical causes of F&M. Particularly in forward-looking analyses, accounting for these factors may require collaboration with other disciplines in the engineering and natural sciences.

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