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Attribution of production-stage methane emissions to assess
spatial variability in the climate intensity of US natural gas
consumption

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E-mail: gruberte@gatech.edu**Keywords:** climate change, natural gas, carbon footprint, methane, spatial attribution, leakageSupplementary material for this article is available [online](#)

Abstract

Although natural gas is often viewed as a commodity fuel with limited variability due to standardization for pipeline transportation, life cycle impacts of natural gas vary substantially. Greenhouse gas (GHG) intensity is one of the most policy-relevant environmental characteristics of natural gas, particularly as decarbonization efforts proceed. Given that natural gas is mostly methane, a powerful GHG, methane emissions from the natural gas system contribute substantially to the GHG intensity of natural gas. Research has established that methane emissions from natural gas systems are climatically relevant and higher than long understood, in part due to variation in production-stage emissions by basin. This work combines recent estimates of basin-level US production-stage methane emissions, data on US natural gas production, consumption, and trade, and a spatial evaluation of pipeline connections between production basins and consumer states to generate first-order estimates of the production-stage methane emissions intensity of natural gas consumed in the United States. Although natural gas is a commodity product, the environmental footprint of a given unit of natural gas varies based on its origin and infrastructural needs. We find that production-stage methane emissions intensity of delivered natural gas by state varies from 0.9% to 3.6% (mass methane emitted from natural gas production sites per mass methane withdrawn). These production-stage emissions add 16%–65% (global warming potential (GWP)-100; 38%–157%, GWP-20) to combustion carbon dioxide emissions. Other sources of life cycle methane emissions downstream of production can be similar in magnitude. Natural gas consumed in Arizona, Kansas, and New Mexico has the highest estimated production-stage methane emissions intensity, largely due to reliance on high-emission basins. Limitations include emissions-related data gaps and sensitivity to allocation approaches, but results demonstrate decision-relevant variability in the GHG impact of natural gas.

1. Introduction

Global climate change is driven by anthropogenic greenhouse gas (GHG) emissions (Intergovernmental Panel on Climate Change 2014). In the United States (US), about 75% of estimated GHG emissions on a CO₂ equivalent (CO₂e) basis are CO₂ emissions from fossil fuel combustion, using 100 year global warming potentials (GWPs-100) from the Intergovernmental Panel on Climate Change (IPCC)'s Fifth Assessment Report (AR5) (EPA 2020). Combustion

CO₂ emissions are relatively easy to quantify because of the direct stoichiometric relationship between carbon in an input hydrocarbon and the carbon in the oxidation product, CO₂. Fossil fuels are extensively traded with high-accuracy public records of flows (e.g. EIA 2020c), so combustion CO₂ emissions can be accurately calculated and attributed without direct emissions measurements.

Among GHGs, the ability to accurately quantify and attribute emissions without direct measurement is essentially unique to combustion CO₂. Other major

GHGs, including methane (CH_4) and nitrous oxide (N_2O), generally enter the atmosphere via direct emissions (like leaks or venting) that are not linearly caused by production or consumption. As a result, emissions of these gases can be estimated but not precisely calculated without direct measurements. For example, estimated emissions of methane, the second-most important GHG from a climate change perspective (Intergovernmental Panel on Climate Change 2014), are either nonspecific (e.g. based on direct atmospheric measurement) or depend heavily on assumptions about difficult-to-measure processes, like leakage and other emissions from the fossil natural gas sector (Brandt *et al* 2014, 2016, Alvarez *et al* 2018). Furthermore, uncertainty about how to characterize non- CO_2 GHGs relative to CO_2 as climate pollutants (e.g. in the form of GWP) presents policy and other challenges associated with climate change mitigation. For example, estimates of the climate intensity of methane relative to CO_2 as measured by GWP increased by about 60% between 1996 and 2014 (Grubert and Brandt 2019), and the value of GWP as a characterization factor is contested (Boucher *et al* 2009). Substantial uncertainty about the magnitude, intensity, and attribution of methane emissions to users poses challenges for policy design and enforcement.

One of the most policy-relevant consequences of uncertainty in non-combustion CO_2 GHG emissions is the challenge of evaluating the climate intensity of natural gas. Although combustion emissions per unit of input energy from standardized, pipeline quality natural gas are similar regardless of source and infrastructure, methane emissions and other life cycle impacts are not. Natural gas, being mostly methane, is a major contributor to climate change if released in its unburned form, making intentional or unintentional releases (here summarized as ‘emissions’) in the natural gas production, transportation, and delivery process important to quantify and mitigate (Caulton *et al* 2014, Saunio *et al* 2016, Ravikumar and Brandt 2017). As of 2018, natural gas accounts for about a third of US primary energy consumption (EIA 2019), with consumer use roughly evenly divided across electricity generation (38%), commercial and residential uses (31%), and industrial uses (31%) (EIA 2020b). This diversity of uses is unusual for an energy resource. As a result, natural gas supplies are subject to both different life cycle processes that contribute to emissions (Grubert and Brandt 2019) and different counterfactuals, depending on the application-specific alternative fuel. For example, for electricity generation, natural gas competes with coal and renewables; for residential and commercial uses, natural gas competes with electricity; and for industrial uses, natural gas competes with electricity and to-be-determined alternatives for deep decarbonization, all with variable system efficiencies and other relevant characteristics. Thus, the specific GHG

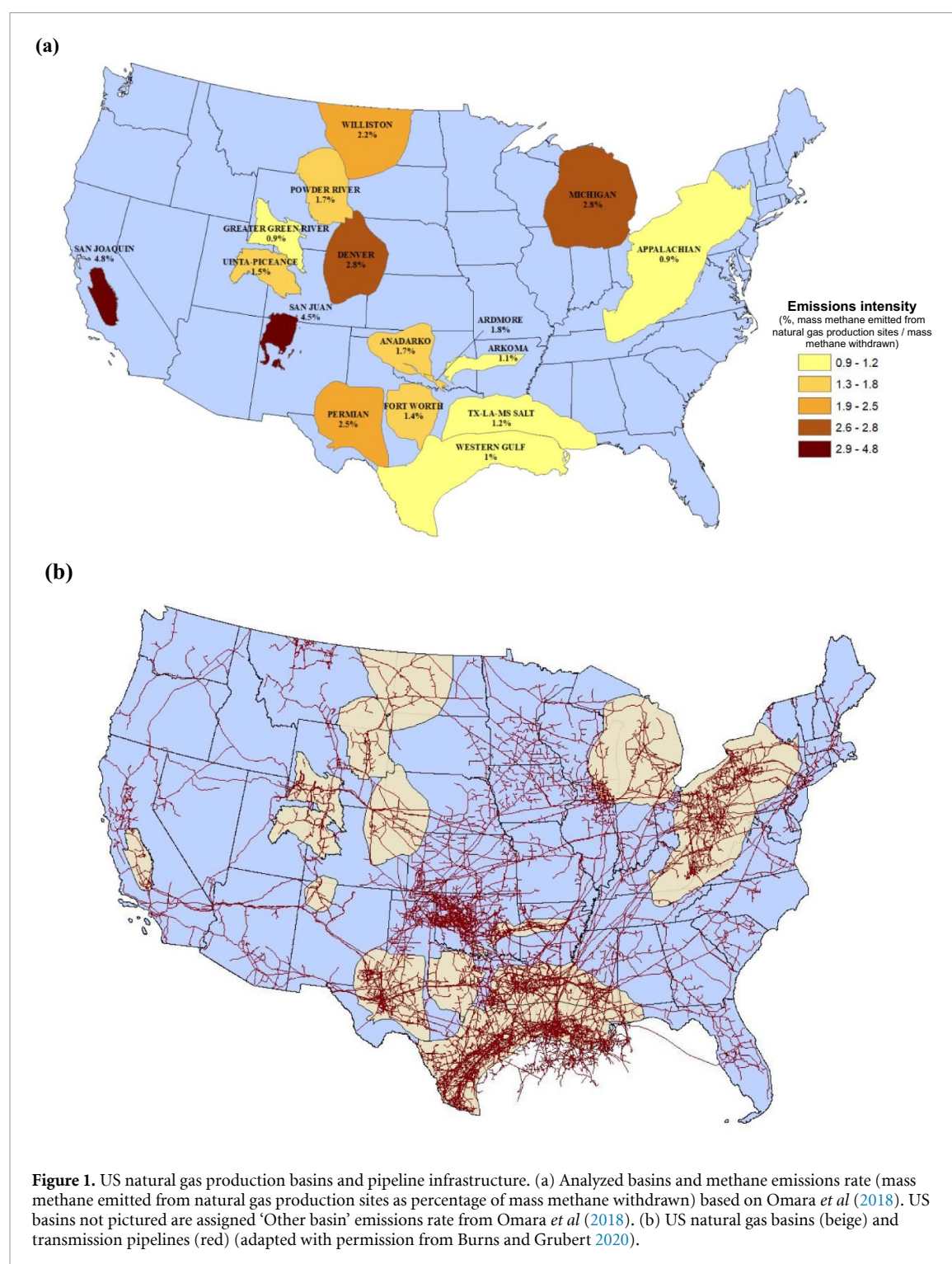
footprint of a given natural gas supply is difficult to estimate based on readily available data and is policy- and climate-relevant because the GHG intensity of the alternative varies by application.

The climate impacts of methane emissions in the US have been an object of intensive study since the emergence of the shale gas industry (Howarth *et al* 2011, Alvarez *et al* 2012, Kongschnik and Boling 2014). The general consensus is that methane emissions in the life cycle of natural gas production and delivery are uncertain, variable, and likely underestimated in official records (Brandt *et al* 2014, 2016, Alvarez *et al* 2018). Based on US average emissions estimates and GWP as a characterization factor, methane emissions add about 30% to natural gas’ GHG footprint on a 100 year basis and double it on a 20 year basis (Alvarez *et al* 2018). On an energy basis, combustion CO_2 emissions from natural gas are about half those from coal (EIA 2018), historically its main competitor in the electricity sector. As such, these methane emissions are both decision-relevant and climatically significant (see, e.g. efforts under the Clean Power Plan to prioritize natural gas- over coal-fired generation for climate reasons (EPA 2015), or the French government’s blocking of a recent proposed liquefied natural gas deal on the grounds that methane emissions from US natural gas are too high (Eaton and McFarlane 2020)).

Methane emissions rates vary meaningfully by natural gas source (production basin) (Omara *et al* 2018). In extreme cases, production-stage emissions alone mean that natural gas from specific basins might have life cycle GHG emissions similar to coal on a 100 year GWP basis (Hausfather 2015). We thus ask: how do production-stage emissions affect the GHG intensity of natural gas consumption by state?

2. Methods

This work builds on the approach described in Burns and Grubert (2020). We combine an assessment of the US natural gas pipeline network with information about 2018 US natural gas production, consumption, and interstate flow to create a first-order, spatially explicit attributional estimate of production-stage methane leakage associated with natural gas consumption at the US state level. The overall goal is to use known information about physical infrastructure to estimate GHG intensity variability of natural gas consumption associated with basin of origin. Prior investigations have evaluated methane emissions of natural gas production at the national or basin level but have not explicitly matched these emissions to consumers in an infrastructurally grounded way. The remainder of this section describes data sources and analytical approach. Relevant data, calculations, assumptions, and results are included in the supplementary data file (SI) (available online at stacks.iop.org/ERL/16/044059/mmedia), an Excel model.



2.1. Data

This work prioritizes use of public, regularly updated data to facilitate access, future updates, and historical investigation. Data on natural gas flows and infrastructure are from US federal sources (DHS 2020, EIA 2020a, 2020b); see SI for details.

Production-stage methane emissions estimates for US basins are not maintained in federal, frequently updated databases. One major challenge for data selection is that assumptions, statistical approaches, and other considerations can vary

substantially across studies. As such, given the goal of characterizing relative production-stage methane emissions intensity associated with natural gas consumption, we prioritized use of a comprehensive data source reporting basin-level estimates of production-stage methane emissions based on a shared set of assumptions. Omara *et al* (2018) is selected due to its comprehensive coverage for US production (17 specific basins accounting for 96% of production, in addition to an 'other basin' category, using year 2015 base data; figure 1).

2.2. Analysis

As methane emissions data are available at the basin level, but production data are available only at the state level, this analysis allocates state-level production to individual basins as follows. If a producing state contains only one natural gas basin (e.g. the Appalachian basin in Pennsylvania), all state production is assigned to that basin. If a producing state contains multiple natural gas basins, production is assigned based proportionally according to natural gas processing capacity by basin in the state, with minor adjustments made to reflect relative production by basin based on state-level production trends between 2015 (base year for Omara *et al* (2018)) and 2018 (base year for this analysis).

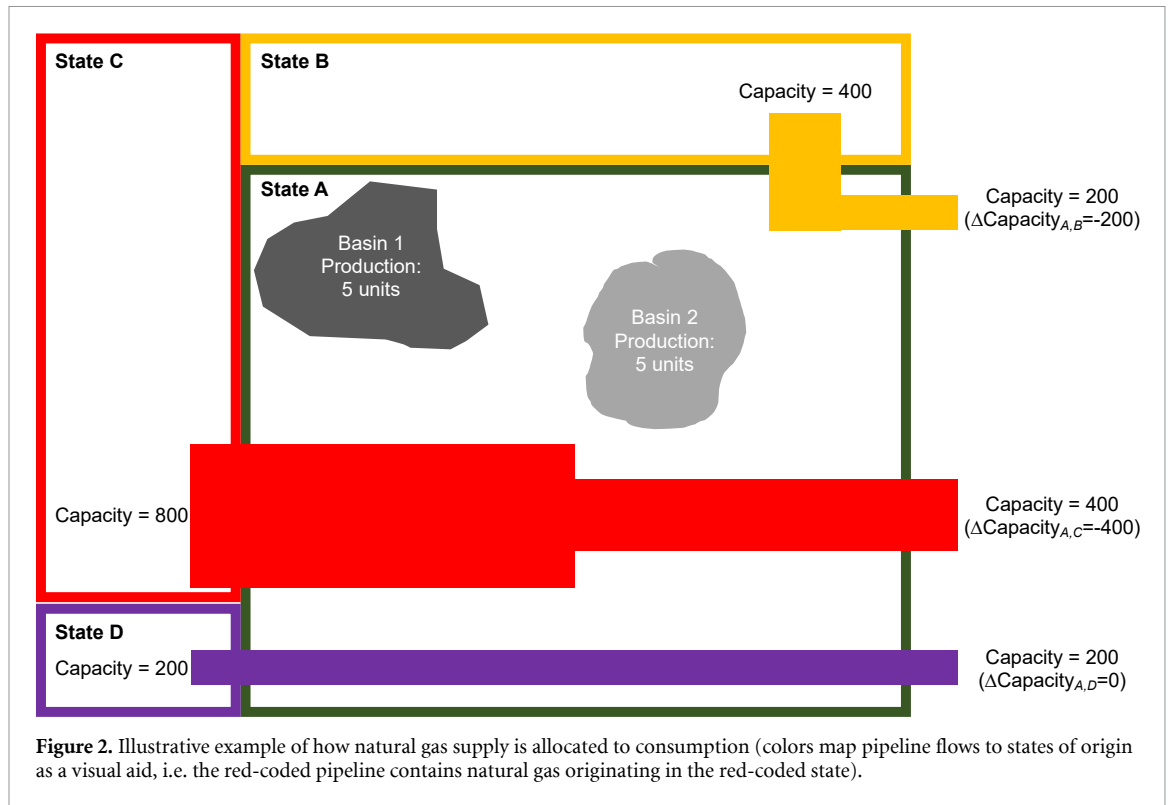
Cherokee Platform production in Kansas and Oklahoma is included in ‘Other US basins’ given low production, similar emissions rate, and difficulty in disaggregating Kansas and Oklahoma production from the Cherokee Platform and unspecified basins based on processing plant locations. Production from 12 states accounting for a total of 39 million cubic feet (mmcf) d^{-1} of 2018 production ($\ll 1\%$ of US dry natural gas production) is excluded from analysis based on a state-level production cutoff of 10 000 mmcf yr^{-1} . Federal offshore (2400 mmcf d^{-1} , 3%) and Alaskan (880 mmcf d^{-1} , 1%) natural gas production are excluded from analysis due to their small contribution, lack of emissions data, and because oil drives those production activities (a rough estimate based on EIA-reported annual average production and spot prices suggest federal offshore natural gas production was worth less than 10% of federal offshore oil production in 2018; 63% of Federal offshore and 98% of Alaskan natural gas was withdrawn from oil wells). Emissions rates from natural gas entering the US from Canada and consumed in the US, which accounts for 2.5% of US consumption in this analysis (SI), are arbitrarily assumed to match those of the Omara *et al* (2018) estimates for the nearest US basins (Williston for natural gas entering from Manitoba and westward provinces; Appalachian for natural gas entering from Ontario and eastward provinces) by default. Given the lack of information on Canadian natural gas methane emissions and the precise origin of Canadian natural gas consumed in the US, we also include a sensitivity analysis for low, medium, and high leakage rates (SI). Natural gas originating outside the US and Canada but consumed in the US, which accounts for an estimated 0.2% of US consumption in this analysis, is assigned the simple-average emissions rate from named US basins included in this analysis. Methane emissions associated with natural gas produced but not consumed in the US (i.e. exports) are not assigned to US consumption.

Each state’s natural gas consumption is modeled as deriving first from its own production, up to the point where either all demand is met (proportionally by production basins) or all production is allocated, whichever is first; and then from states from which it had net positive receipts. The main analytical challenge, addressed in this work by using information about the pipeline system to assign flows, is determining how much natural gas that enters a state from a given source is consumed in that state versus exported further, and tracing these flows back to basins of origin. For example, California receives large volumes of natural gas from Arizona, which receives far more than it consumes from New Mexico. New Mexico produces large amounts of natural gas, in addition to having net receipts from Colorado and Texas, both of which are also producers; and Texas has net receipts from Oklahoma, which in turn is a major producer that imports from Colorado. In this example, California’s net receipts from Arizona ultimately originate in New Mexico, Colorado, Texas, and Oklahoma.

The pipeline system’s redundancy and networked nature means that consumption cannot be assigned to supply based on simple pipeline traces (figure 1(b)). The key assumption made in this analysis is that reductions in physical pipeline capacity within a state are reasonable proxies for the relative contribution of supply from a given pipeline to consumption in that state—that is, if a pipeline is smaller when it leaves a state than when it entered, we assume the state consumed some natural gas and use this value to allocate known 2018 natural gas consumption across suppliers. For each consuming state, changes to physical pipeline capacity from state entry to state exit are summarized by pipeline operator and assigned to a state of origin using geographic information system (GIS) (figure 1(b); SI, ‘Pipeline Summary’). States are assumed to consume natural gas only from pipeline operators with a drop in physical pipeline capacity within the consuming state. Consumption is allocated proportionally across states of origin based on share of net negative natural gas movement across the consumer state.

As an illustrative example, let Prod_x be natural gas production in state x , with $\text{Prod}_{x,j}$ production in state x from basin j ; and Cons_x be natural gas consumption in state x , with $\text{Cons}_{x,y}$ the consumption in state x of natural gas received from state y . Further, for pipelines entering state x from state n , let $\Delta\text{Capacity}_{x,n}$ be the total capacity of pipelines originating in state n upon exit from state x less the total capacity of the same pipelines upon entry to state x . Let i be all states for which $\Delta\text{Capacity}_{m,i}$ is negative. Now consider the example illustrated in figure 2, and assume $\text{Prod}_A = 10$ and $\text{Cons}_A = 100$.

Then the attributional rules assign supply to consumption in state A as follows:



$$\text{Cons}_{A,A} = \min(\text{Prod}_A, \text{Cons}_A) = \min(10, 100) = 10 \text{ units from state } A$$

$$\text{Cons}_{A,B} = (\text{Cons}_A - \text{Cons}_{A,A}) \times \frac{\Delta \text{Capacity}_{A,B}}{\sum_i \Delta \text{Capacity}_{A,i}} = (100 - 10) \times (-200 / -600) = 30 \text{ units from state } B$$

$$\text{Cons}_{A,C} = (\text{Cons}_A - \text{Cons}_{A,A}) \times \frac{\Delta \text{Capacity}_{A,C}}{\sum_i \Delta \text{Capacity}_{A,i}} = (100 - 10) \times (-400 / -600) = 60 \text{ units from state } C$$

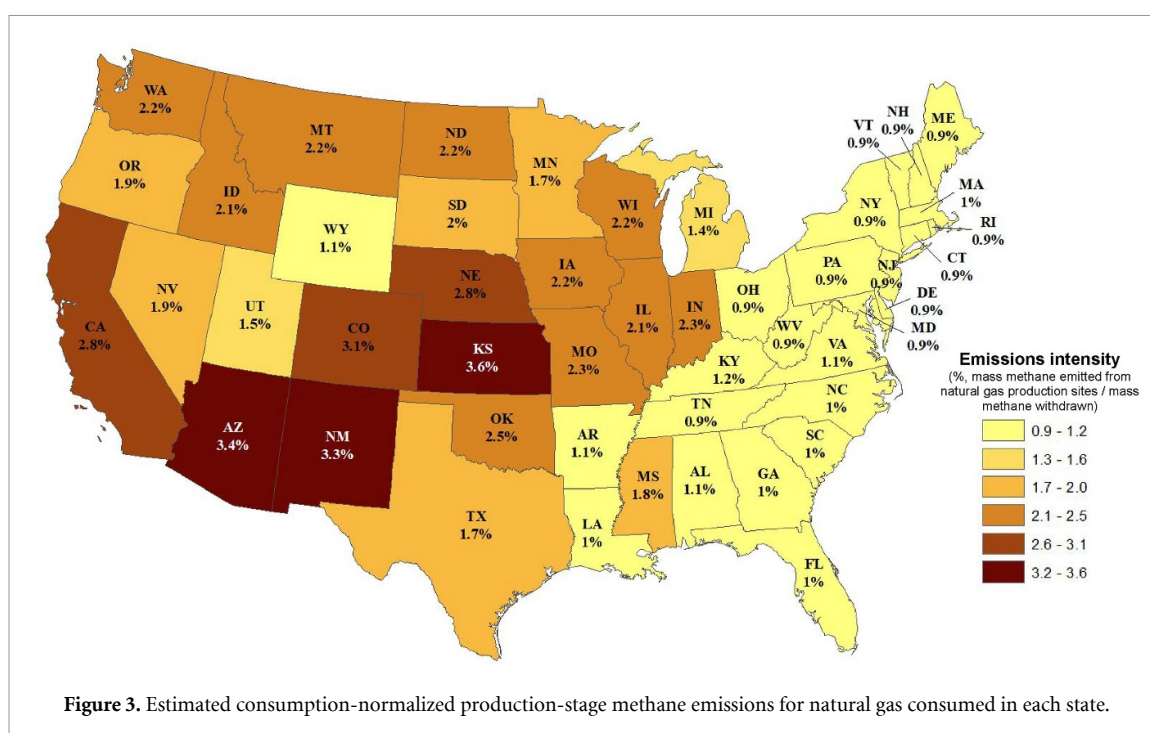
$$\text{Cons}_{A,D} = (\text{Cons}_A - \text{Cons}_{A,A}) \times \frac{\Delta \text{Capacity}_{A,D}}{\sum_i \Delta \text{Capacity}_{A,i}} = (100 - 10) \times (0 / -600) = 0 \text{ units from state } D.$$

Natural gas supply from within the consumer state x ($\text{Cons}_{x,x}$) is assumed to be proportionately distributed across production basins in state x . Natural gas receipts from other states y consumed in state x ($\text{Cons}_{x,y}$) are allocated to basins either based on a clear geographic relationship identified manually using GIS (e.g. Nebraskan imports from Colorado originate in the Denver basin via the Trailblazer Pipeline, east of the Rocky Mountains; see figure 1 and SI) or based on the average basin distribution of exported gas from state y , given gas comingling in heavily networked systems. This average basin

distribution is calculated iteratively based on relative volumes of self-production or net receipts from other states that are passed through rather than consumed in state x . The resulting natural gas attribution is thus infrastructurally grounded based on the pipeline network, while preserving observed 2018 trade relationships anchored to state-level 2018 natural gas consumption.

Consumption-normalized production-stage methane emissions for natural gas consumed in each state are reported as follows:

$$\sum_{i=\text{basin}} \left(\frac{\text{methane mass emitted from natural gas production sites}_i}{\text{methane mass withdrawn}_i} \times \frac{2018 \text{ natural gas consumption in state originating in basin}_i}{2018 \text{ total natural gas consumption in state}} \right).$$



See supplementary data file 1, tab ‘Emissions rate calculations,’ for exact calculations.

3. Results

Figure 3 shows the estimated consumption-normalized production-stage methane emissions for natural gas consumed in each state as defined above (see SI, ‘Emissions rate calculations’).

Consumption-normalized production-stage methane emissions by state range from 0.9% to 3.6%. The southwest and central US have the highest estimated natural gas production-stage methane emissions in the country, largely due to reliance on relatively high-emissions production regions like the Permian, San Juan, and ‘other’ basins in the mid-continent. By contrast, the East Coast is largely supplied by the low-emissions Appalachian basin, which includes the Marcellus shale (figure 1). Figure S1 shows sensitivity to lower and upper bound estimates for basin emissions rates taken from Omara *et al* (2018).

For natural gas produced in the US, this work’s estimated production-weighted average estimated production-stage emissions rate for 2018 is 1.4% (mass emitted from natural gas production sites/mass withdrawn), compared with 1.5% estimated in the source data (Omara *et al* 2018). The shift likely reflects a disproportionate increase in US production from lower-emissions basins (e.g. the Appalachian basin) between 2015 (source data base year) and 2018 (this study’s base year) (EIA 2020b). Interpretive caution is recommended given that only production and consumption, not emissions rates by basin, were adjusted to 2018.

Figure 3 reflects the default assumption that Canadian natural gas supplies have methane emissions that match those of nearby US basins. Figure S2 shows sensitivity to emissions rates for Canadian natural gas consumed in the US, with results shown for 1% (panel a), 3% (panel b), and 4.5% (panel c) production stage emissions (mass emitted from natural gas production sites/mass withdrawn). These illustrative equal interval sensitivity levels are chosen based on low (e.g. Appalachian basin, 1%; Texas–Louisiana–Mississippi Salt, 1.2%), medium (e.g. Michigan or Denver basins, 2.8%), and high (e.g. San Juan basin, 4.5%; San Joaquin basin, 4.8%) leakage levels associated with US production. Our mid-range scenario (3%) also matches a high-uncertainty estimate of natural gas production site-based emissions for the Red Deer region of Alberta, Canada (Zavala-Araiza *et al* 2018). California, the Pacific Northwest, the Midwest, and parts of New England are most sensitive to production-stage methane emissions rates associated with Canadian natural gas.

For natural gas supplies in some southwestern and central states, production-stage methane emissions alone add roughly 50% to combustion CO₂ intensity on a GWP-100 basis (see SI, ‘Emissions impacts on end uses’). In California, which has strict GHG intensity rules in the electricity sector (CEC 2006, Grubert *et al* 2020), methane emissions add 64% to natural gas-fired electricity combustion GHG emissions (GWP-100; +155% at GWP-20) assuming this work’s estimate for production-stage methane emissions associated with natural gas consumed in California, national-average methane emissions for gathering through transmission/storage (Alvarez

et al 2018), and no methane emissions at the power plant. In New York, despite relatively low estimated production-stage methane emissions associated with the natural gas supply, state climate law uses GWP-20 (NYSERDA 2019). Accordingly, natural gas-fired power plant GHG emissions are an estimated 76% higher than combustion CO₂ emissions (GWP-20; +31% at GWP-100) assuming this work's estimate for production-stage methane emissions associated with natural gas consumed in New York, national-average methane emissions for gathering through transmission/storage (Alvarez *et al* 2018), and no methane emissions at the power plant.

4. Discussion

This analysis demonstrates that existing data about natural gas flows and knowledge of physical infrastructure like processing plants and pipeline networks can be used to generate a first-order allocation of basin-specific upstream impacts, such as methane emissions, to end-users. This allocation helps differentiate environmental impacts across what has previously been represented as a homogenous commodity. This work shows that basin of origin has decision-relevant impacts on overall GHG emissions associated with natural gas consumption.

Direct application of these results to policy and decision processes is still challenging, as production-stage methane emissions attribution is subject to meaningful limitations. Specifically, attribution is sensitive to methodological decisions to the point where alternative interpretations could lead to qualitatively different results. Particularly as more natural gas users, state governments, and the federal government commit to strict decarbonization targets, including 'net zero' targets that rely on determining equivalent emissions for sometimes categorically different activities, accurately attributing GHG emissions is likely to become more important for compliance, financial responsibility for fees or taxes, and other increasingly formal regulatory processes. As this analysis shows, production-stage emissions associated with natural gas supplies are sufficiently variable, and estimates of the climate intensity of natural gas used in policy and beyond are sufficiently large, that accurate evaluation and attribution of methane emissions is highly relevant for climate action.

The inability to accurately calculate methane emissions without direct measurements is a key source of uncertainty, particularly because of the disproportionate contribution of unusual 'super emitter' events to total emissions (Zavala-Araiza *et al* 2015, Brandt *et al* 2016, Caulton *et al* 2019). Data gaps on spatial variability of methane emissions downstream of production mean that full life cycle results for spatially specific methane emissions estimates by state could be qualitatively different than the production-stage estimates presented here. These

data gaps are particularly relevant given that direct measurements are exceptionally difficult to acquire without data restrictions like location confidentiality. As such, it is difficult to confirm whether potentially emissions-relevant, spatially variable confounding variables (e.g. maintenance intensity; soil moisture; seismic activity; etc) have been sufficiently evaluated in development of activity factors. Another potentially significant source of error related to measurements is that this analysis is a 2018 snapshot for state-level (rather than basin-level) production, consumption, and trade, relying on 2015-base year estimates of basin-specific emissions rates. Emissions rates change across space (including equipment) and time in ways that are not easily and precisely predictable (Englander *et al* 2018), which is a challenge for accurate attribution.

Estimated flow relationships between production basins and consumer states as published here might not be easily extrapolated to past or future years, particularly because of substantial redundancy in the US pipeline system. Modeled flows depend heavily on manual manipulation of base year (2018) data for production, consumption, and interstate trade. Changes to spatial distribution of production and consumption could easily result in substantially different relationships and attributed production-stage methane emissions. For example, Pennsylvania did not produce more natural gas than it consumed until 2011 and was able to import sufficient natural gas prior to its production boom, relying on still extant pipelines (EIA 2020b). Relatedly, pipeline directionality can vary by season, and actual rather than net natural gas supplies could have different emissions profiles. In practice, the impact could be low: seasonality is most likely relevant along the heavily networked East Coast, with high northern winter demand for natural gas heat and high southern summer demand for air conditioning that affect the fate of Appalachian versus TX–LA–MS Salt and Western Gulf natural gas, but these three basins have similar estimated production-stage emissions rates (figure 1).

Other major sources of analytical uncertainty in this estimate are related to explicit assumptions rather than measurements, particularly related to allocation approaches. For example, when wells produce natural gas in addition to coproducts like oil and natural gas liquids (NGLs), how methane emissions are assigned to each coproduct has major implications for GHG intensity estimates. A close match between the number of wells defined as 'natural gas production sites' in the source data for this work's emissions estimates (Omara *et al* 2018) and EIA's designation of 'natural gas wells' based on gas–oil ratio (EIA 2020c), at 578 000 versus 570 000 natural gas wells out of 1030 000 total US oil and gas wells in 2015, suggests that Omara *et al* effectively use a well-level primary purpose allocation (2018). Allocating impact based on infrastructure's primary

purpose is an imperfect proxy for allocating impact based on the cause of the emission, resulting in all-or-nothing bias at the individual well (and maybe field) level. This approach, however, is easily implemented and likely better reflects emissions causation at the system level than assigning all emissions from combined oil, NGL, and natural gas production to the natural gas system, which overestimates emissions associated with natural gas relative to other products (Allen *et al* 2021).

Why does allocation approach matter? Although allocation might not matter significantly for policy implementation at the producer level if the same actors are engaged in natural gas, oil, and NGL production, where mechanisms like flare requirements apply to a well regardless of its product distribution, it is extremely important for evaluating emissions intensity of consumption. For example, consider a situation where methane is produced as a low-value byproduct of oil production, and the methane is commonly flared or vented rather than marketed. Assigning venting emissions to the natural gas system for that basin would not necessarily affect policy interventions on the producer side. An unintended consequence, however, is that assigning all methane emissions to the natural gas could result in penalties (e.g. a carbon tax) for would-be consumers who might otherwise recover flared or vented methane for use due to the high apparent emissions assigned to byproduct gas, while oil consumers would see no penalty for oilfield practices resulting in widespread venting. Allocation across coproducts is a common problem for environmental assessment, for both theoretical and implementation reasons: for a discussion of a similar allocation issue for water consumption from multipurpose reservoirs, see (Grubert 2016).

Another significant allocation assumption in this work is that states are assumed to consume their own production first. States have substantial regulatory authority for methane emissions (DOE 2019), so assuming that states consume their own production first means that states are assigned the emissions over which they exercise the most control, even if their own demand might not cause production of a marginal unit of in-state gas. More generally, the assumption that natural gas production should be allocated to natural gas users based on infrastructural relationships results in different conclusions than assumptions of demand-driven responsibility for marginal production from a given basin. For example, consider a situation where West Coast demand for natural gas grows significantly, resulting in diversion of natural gas produced in Texas from East Coast to West Coast markets enabled by a highly networked pipeline system. If Pennsylvania natural gas production grows as a result but physically supplies the East Coast users who were previously using Texas gas, which consumers are responsible for the Texas versus

Pennsylvania methane emissions? Although producer/consumer relationships are mediated by physical constraints like pipeline access, assigning production impacts to specific consumption based on physical flows is not the only reasonable attribution approach.

Variability in the GHG intensity of natural gas supplies can be large and decision-relevant, even when only production-stage emissions are evaluated. Assessing and attributing methane emissions to particular entities is likely to become more relevant given increasingly widespread and increasingly formal GHG targets at various levels of governance. More work is needed to accurately estimate and attribute methane emissions throughout the natural gas supply chain to specific sources and uses of natural gas, both related to data and standard assumptions about allocation, characterization, and drivers of spatiotemporal variability.

Data availability statement

All data that support the findings of this study are included within the article (and any supplementary files).

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