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Letter

Consistent Metrics Needed for Quantifying Methane Emissions from Upstream Oil and Gas Operations

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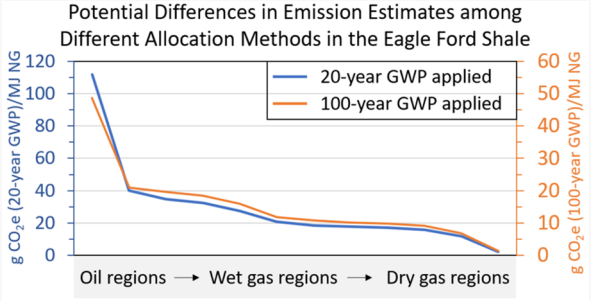
ABSTRACT: Methane emissions from oil and natural gas sources are often characterized as a methane emissions intensity, which is typically defined as methane emissions divided by natural gas production. Reporting methane emission intensities implicitly assigns all methane emissions from production activities to natural gas, but many of the regions that supply large amounts of natural gas to world markets simultaneously produce natural gas, natural gas liquids, and oil. The importance of whether methane and other greenhouse gas emissions from production activities are allocated to natural gas alone or to multiple products was examined using data from the Eagle Ford Shale production region in south central Texas. In the Eagle Ford, differences in emission allocation methods can produce differences in estimated emissions of 50−110 g CO_2e/MJ of natural gas. This is comparable to the difference in combustion emissions between coal and natural gas.



INTRODUCTION

Natural gas production and use have increased substantially over the past decade. In the United States, now the world's largest natural gas producer, approximately 40.9 trillion cubic feet of natural gas was produced in 2019, providing more than 40 quadrillion BTU (quads) of energy. In contrast, 15 years earlier, in 2004, approximately 24 trillion cubic feet of natural gas was produced, delivering ∼25 quads of primary energy.[1] Globally, natural gas provides approximately 140 quads of primary energy, and the United States exported 4.6 trillion cubic feet of gas to these markets, an amount that has increased by a factor of 5 since 2004. This means that natural gas from the United States, now largely produced using horizontal drilling and hydraulic fracturing of shale formations, is both an important domestic energy source and a global product.

Increased use of natural gas can result in lower carbon dioxide emissions if it displaces the use of coal or petroleum; however, these lower greenhouse gas emissions of natural gas can be eroded by emissions of methane. Methane, the principal component of natural gas, is a greenhouse gas with a global warming potential (GWP) 28−34 times higher than carbon dioxide over a hundred year period.[2]

As global trade in natural gas increases, users of natural gas are increasingly calling for accounting of greenhouse gas emissions associated with producing the fuel, including methane emissions. For global trade in natural gas to effectively account for greenhouse gas emissions, clear, consistent, and transparent metrics for greenhouse gas emission reporting are needed. The emissions reporting systems currently in place, however, are heterogeneous and can lead to significant differences in the greenhouse gas emissions attributed to natural gas from different types of sources.

Methane emissions from oil and natural gas sources are often reported as a methane emission intensity. Methane emission intensity has generally been defined either as methane emissions divided by methane production or as methane emissions divided by natural gas production. This measure of methane emissions has been reported in many measurement studies, including "top-down" measurements, and "bottom-up" measurements".[3] While this metric has the merit of being readily understood, it also has the potential to lead to double counting of methane emissions in oil and gas production regions that produce both natural gas and hydrocarbon liquid products. In the United States, the Permian, Bakken, Denver Julesburg (Niobrara), Eagle Ford, and southwestern Marcellus production region all produce substantial quantities of hydrocarbon liquids along with natural gas, and the gas produced in these regions accounts for a substantial fraction of total United States production.

For regions that produce liquid hydrocarbon products along with natural gas, methane emissions must be allocated to one or more of the products. A methane emission intensity metric implicitly assigns all methane emissions to natural gas. This

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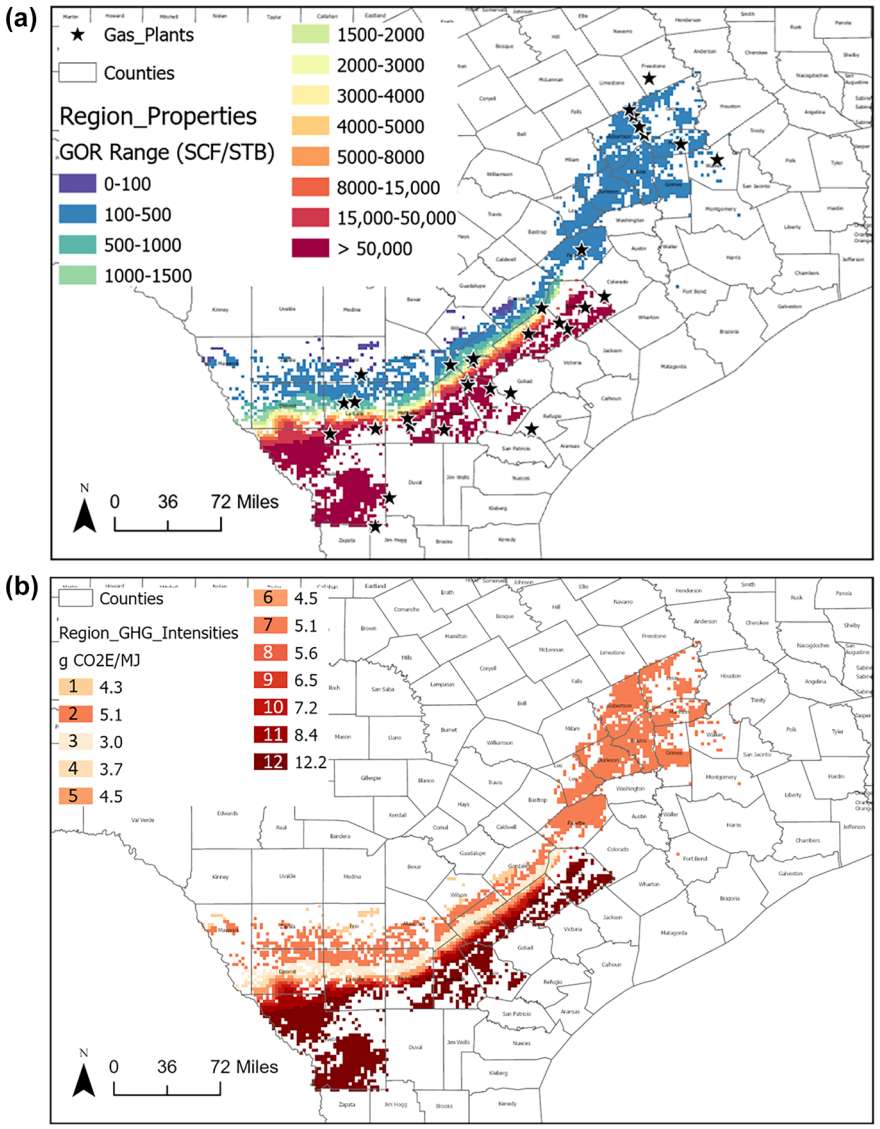

Figure 1. Gas-to-oil ratios of Eagle Ford wells (a) and variation in greenhouse gas emission intensities (emissions divided by energy content of all products) (b).[8,14]

emission allocation is not consistent, however, with emission allocation schemes used for other types of fuels. The life cycle assessment (LCA) community has developed approaches to distributing emissions from multiproduct processes to individual fuel products. As an example, consider the evaluation of greenhouse gas emissions associated with gasoline fuels, as they are evaluated for compliance with the California Low Carbon Fuel Standard (LCFS)[4] or renewable fuel standards for transportation fuels. In performing these evaluations, emissions from petroleum refineries must be allocated among the multiple products produced by a refinery. For example, greenhouse gas emissions associated with the energy consumed in a crude oil distillation column are allocated among all of the products and product precursors emerging from that column (gasoline, diesel, jet fuel, lubricating oil, and others), based on the energy content of the products.[5−7] If straight run gasoline emerging from a crude oil column accounts for 10% of the energy content of the product and product precursor streams emerging from that column, it would be assigned 10% of the emissions associated with operating the column.

Similarly, if an oil and gas production region generates natural gas, natural gas liquids (NGLs, largely ethane, propane and butanes), and petroleum liquids (crude oil and condensate), then greenhouse gas emissions associated with the production region would be assigned to all of the products (natural gas, NGLs, and petroleum liquids), based on the total energy content of each of the product flows. This distribution of emissions among products is referred to as an allocation method and is used in LCA tools, which in turn may be used in evaluating compliance with regulations. While other allocation methods, based on mass, or market value, are possible for products from oil and gas production regions, energy allocation is a rational choice given that the products are valued for their energy content rather than their mass, and market values can fluctuate over time. In regions such as the Eagle Ford Shale of south central Texas, which produce substantial quantities of natural gas, natural gas liquids, and oil, substantial fractions of greenhouse gas emissions are attributed to each product. A recent assessment concluded that approximately half of the greenhouse gas emissions in the Eagle Ford region would be assigned to natural gas and half to natural gas liquids and oil,

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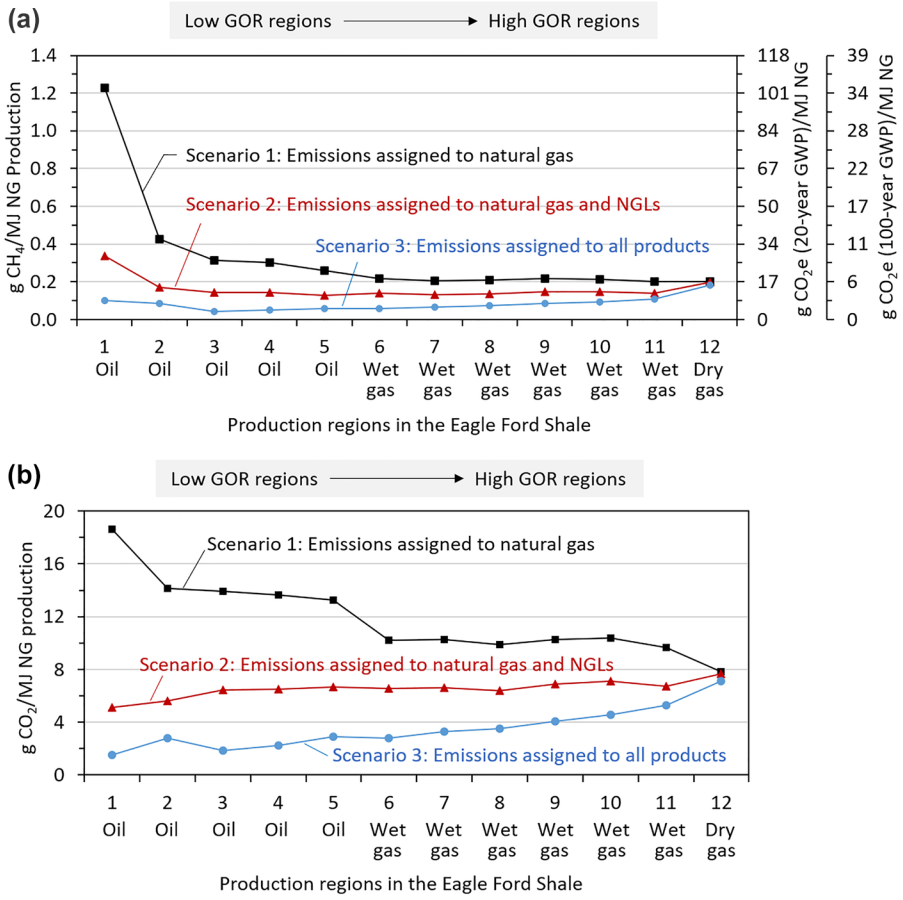

Figure 2. (a) Emissions of methane assigned to natural gas in 12 subregions in the Eagle Ford oil and gas production region, assuming all emissions are assigned to natural gas (Scenario 1). Emissions are allocated between natural gas and natural gas liquids (Scenario 2). Emissions are allocated to oil, natural gas, and natural gas liquids (Scenario 3). (b) Carbon dioxide emissions attributed to natural gas for the same scenarios.

using energy-based allocations.[8] A similar assessment for the Permian Basin would assign only about 30% of greenhouse gas emissions to the natural gas product, if emissions were attributed based on the energy content of the produced oil, natural gas, and natural gas liquids. In contrast, almost all emissions would be assigned to the natural gas product in basins that produce few liquid products.

Consistency in allocation methods is important if different routes to low carbon fuels are to be compared. Without accounting for coproducts in oil and gas production regions, greenhouse gas emissions associated with natural gas production will be overestimated compared to peer fuel pathways, including petroleum and biofuels, for which coproducts have been allocated emissions (e.g., electricity in the case of cellulosic ethanol or animal feed in the case of corn grain ethanol).[9,10] Further, should oil from a natural gas production region be assigned greenhouse gas emissions without considering that all methane or total greenhouse gas emissions in that region had been assigned to natural gas, double counting of emissions will be an inevitable outcome. Double counting has been addressed for other coproduced energy products but not in the instance of oil and gas region products.[11] To illustrate the magnitudes of differences in reported greenhouse gas emissions that can result from different emissions allocation methods, this letter uses data from the Eagle Ford Shale in south Central Texas.

MATERIALS AND METHODS

Case Study Region. The Eagle Ford Shale is an oil- and gas-producing region in south central Texas that includes oil wells, wet gas (oil and natural gas production) wells, and dry gas wells. Data from 2013 are used in the assessment, since the performance of a 2013 basin-wide emission inventory was evaluated using observational data.[12] In 2013, the Eagle Ford Shale produced approximately 1 million barrels (bbl) of oil (approximately 160 million liters) and 4 billion standard cubic feet (scf) of gas per day (approximately 0.11 billion m^3 gas/day), leading to an average gas-to-oil ratio (GOR) for the region of 4000 scf/bbl.[13] However, GORs at individual wells, and in subregions within the Eagle Ford, range from less than 2000 to more than 50,000.[13] This wide range in GORs makes the subregions within the Eagle Ford representative of a broad range of natural gas production regions.

Greenhouse Gas Emissions. Greenhouse gas emissions for 12 subregions within the Eagle Ford have been reported by Chen et al.[8] These subregions are shown in Figure 1a and have GORs that range from less than 2000 in regions 1−5 (oil wells) to >50,000 in region 12 (dry gas wells).[14] Emissions were estimated at the equipment level at well sites and at the facility level for gathering and processing facilities. Production of methane, ethane, propane, butanes, and liquid products were estimated and tracked at the individual well level,[8] allowing emissions to be allocated to either single products or multiple products. A mapping of greenhouse gas emission

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intensities, where the emissions are normalized by all of the energy products, is provided in Figure 1b. Details of system boundaries and sources of data are provided in the Supporting Information (SI).

Methane Emission Allocation Scenarios. Energy-based allocation is applied in this work since oil and gas products are primarily energy products. Methane emissions allocated to natural gas were calculated for three scenarios in each of the 12 subregions of the Eagle Ford: (1) assign all methane emissions to the natural gas product, (2) assign all methane emissions to the natural gas and the NGLs, allocating emissions between the natural gas and NGLs based their energy content, and (3) assign methane emissions to natural gas, NGLs, and oil, allocating emissions among the three products based their energy content. Scenario 1 is consistent with a methane emission intensity reporting scheme. Scenario 3 is consistent with commonly used LCA allocation approaches.[5] Scenario 2 is an intermediate choice that highlights the importance of distinguishing between the natural gas product and all of the produced gases (methane, ethane, propane, and butane). Methane emissions will be reported in units of g of methane emissions per MJ of energy content of the products. Results also are reported as carbon dioxide equivalents (CO_2e) per MJ of energy content of the products, using global warming potentials[15] of 28 (100 year GWP) and 84 (20 year GWP).

Carbon Dioxide Allocation Scenarios. The emission allocation scenarios used for methane were also applied to carbon dioxide emissions in each subregion. A large fraction of the carbon dioxide emissions in the Eagle Ford region are associated with gas compression and gas processing. Scenario 1 assigns all of these emissions to natural gas. Scenario 2 allocates these emissions between the natural gas and NGL products that are compressed and processed. Scenario 3 assigns some of these compression and processing emissions to oil products.

RESULTS AND DISCUSSION

Figure 2 reports methane emissions and carbon dioxide emissions assigned to natural gas under the three allocation scenarios. Scenario 1 assigns all of the emissions to natural gas. Scenario 2 assigns the emissions to natural gas and natural gas liquids based on their energy content. Scenario 3 assigns emissions to oil, natural gas, and natural gas liquids based on their energy content. For the methane contributions reported in Figure 2a, multiple vertical scales are presented, using a 100-year GWP for methane, a 20-year GWP for methane, and the mass of methane, all normalized by the energy content of the natural gas. If GWPs other than the 20-year and 100-year values used in this work are preferred, the mass of methane can be combined with alternate GWPs to calculate carbon dioxide equivalents.

The fractions of emissions assigned to natural gas using the three allocation scenarios are similar for methane and carbon dioxide; however, the carbon dioxide equivalents associated with the methane emissions are much larger than the carbon dioxide emissions, making the choice for methane emission allocation the most significant issue. The magnitude of the difference in total emissions allocated to natural gas can be up to 50−110 g CO_2e/MJ fuel, depending on the GWP chosen for methane. Since the difference in the combustion emissions between a MJ of coal (85% (mass) C, 25 MJ/kg heating value) and a MJ of natural gas (75% (mass) C, 50 MJ/kg) is approximately 70 g CO_2/MJ, the choice of allocation methods for upstream emissions will determine, for many natural gas supply chains that involve multiple products, whether life cycle greenhouse gas emissions for natural gas are greater or less than those for coal. The differences between allocation methods are largest for the oil-producing subregion of the Eagle Ford (regions 1−5), smallest for the dry gas production region (region 12), and intermediate for the wet gas regions (regions 6−11). Because it has these different types of production, the Eagle Ford and its subregions can be viewed as broadly representative of many types of production regions.

As global systems for characterizing emissions from natural gas value chains emerge, clarity and transparency are critical. For natural gas from wet gas and oil production regions, the choice of method for allocating emissions among the natural gas, natural gas liquid, and oil will have a significant impact on the greenhouse gas emissions attributed to these products. This choice of allocation method is a policy decision, informed by scientific and engineering analyses; it is not a purely scientific decision since, for all of the choices, all emissions are accounted for, and the choice merely determines how to assign the emissions among different products. To promote clarity and transparency, and until a global consensus is reached regarding the most appropriate allocation method for upstream oil and gas emissions, if normalized methane emissions are reported, they should be reported on three bases: normalized by the energy content of the natural gas produced, by the energy content of the natural gas and natural gas liquids produced, and by the energy content of the oil, natural gas, and natural gas liquids produced. If a normalized emission unit expressed as a percentage is desired, the methane emissions could be reported based on their energy content. This type of reporting requires knowledge of product flows in oil and gas production regions, but these data are broadly available, as described in the SI.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.estlett.0c00907.

Descriptions of data sources, discussion of system boundaries and uncertainties, and descriptions of sources of product flow information (PDF)

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Notes

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