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Methane emission intensity metrics: unmasking the trade-offs

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Abstract
Reducing methane emissions is essential to slowing near-term climate warming, and the oil and gas industry is a major anthropogenic source offering some of the lowest-cost, most readily-available mitigation options. Regulators, investors, and voluntary initiatives are increasingly focused on differentiating oil and gas by the methane emitted during production and delivery. For example, the European Union—the world's largest fossil fuel importer—is implementing an import standard with a maximum methane intensity, and major producers representing nearly half of global production have pledged to reduce emissions to near-zero levels (0.2% loss rate). However, consistent methane intensity metrics are needed to provide meaningful comparisons across the diverse industry, chosen from the myriad options. Using industry-reported and aircraft-measured emissions data from Canada and the U.S., we show that different metrics considerably alter the ranking of best/worst methane performers. Methane loss rate (methane lost per methane produced) better ranks gas producers, while energy intensity (methane lost per energy produced) more favourably ranks oil producers. Since neither metric alone provides a complete picture, we recommend reporting both. The methane loss rate measures gas-handling performance, while energy intensity provides a broader look at resource production efficiency. Together, these metrics will provide a diversity of user groups with the data they need to make effective decisions.

1. Introduction
Reducing both methane (CH_4) and carbon dioxide (CO_2) emissions is essential for addressing climate change, but their impacts differ: CO_2 accumulates in the atmosphere, driving long-term warming, while methane is a potent short-lived climate forcer, meaning its mitigation offers a unique opportunity to slow the rate of increase in near-term warming[1–4]. Among anthropogenic methane sources—such as oil and natural gas, coal, agriculture, and waste—the oil and gas sector has received the most attention in recent years due to the demonstrated (cost-)effectiveness of abatement technologies[5,6]. Accurate, measurement-based emission quantification remains the key to effective mitigation, and growing international commitments, regulations, and technological advancements have improved mitigation prospects[7]. Increasingly, oil and gas producers and governments are linking market access to methane performance, and there is a need for transparent and consistent metrics to calculate and report methane emissions intensity – the emissions per marketed hydrocarbons. However, the lack of standardized metrics and methodologies creates challenges for comparability and enforcement.

Defining consistent emission intensity calculation methods for fossil fuel supplies is essential for international comparison, but intensities have been expressed in myriad ways, calculated at different aggregation levels (e.g., site-, operator-, or field-level), and using different normalizing factors. The impacts of choosing one metric over another is unclear, and the overlap of units and terminology often leads to confusion about which metric is being presented. Broadly speaking, there are two types of methane intensity metrics used to quantify upstream emissions: (1) gas-based and (2) oil and gas-based intensity. Gas-based intensity compares

methane emissions to natural gas (or methane) produced/marketed, while oil and gas-based intensity relates emissions to combined production, usually in terms of produced energy. While methane emissions has been the primary focus, some metrics attempt to also include CO_2 or other greenhouse gas emissions (e.g., from flaring or indirect emissions) on a CO_2-equivalent (CO_2e) basis.

Despite the lack of consistency, emission intensity thresholds exist in regulatory requirements and as part of voluntary initiatives globally. Some of the most prominent targets rely on gas-only metrics. For example, the Oil and Gas Climate Initiative (OGCI) and Oil and Gas Decarbonization Charter (OGDC) – representing nearly half of global oil and gas production – have committed to the near-zero methane loss rate of 0.2%[8,9]; the United States' Waste Emissions Charge required producers to pay a fee for emissions above 0.2% methane loss rate[10]; gas-only performance requirements have also been set in China[5] and in part of Canada[11,12]. There are also oil and gas-based metrics and targets outlined by industry initiatives[13–18] and regulators[10,19]. Finally, the European Union – the world's largest importer of fossil fuels – will impose methane intensity limits on imported oil and gas, starting in 2030[20].

We explore available methane emission intensity metrics for characterizing oil and gas supplies. We describe their calculation methods/variants, terminology, and provide example usage globally. Using industry-reported, producer-level emissions data from Canada, and aircraft-measured regional emissions in both the United States and Canada, we explore the potential implications/biases of choosing one intensity metric over another. Our findings demonstrate the value of both classes of intensity metric for transparent reporting, supporting their use across the diverse global oil and gas industry. We limit this discussion to methane emissions from oil and gas production, but emissions from processing and transmission systems flow easily from production metrics, as the denominator is the throughput of the system.

2. Methane Emission Intensity Metrics

Table 1 summarizes key intensity calculation protocols and intensity targets for different industry initiatives and regulatory jurisdictions, illustrating the wide variety of methane (or CO_2e) emission intensity requirements that currently exist. Even for protocols/jurisdictions using the same metric, the application to different site types, the use of emissions allocation, and the choice of denominator can all vary. While there has been widespread adoption by industry of the OGCI/OGDC metric – covering nearly half of global oil and gas production – they have been deployed inconsistently.

Table 1. Summary of oil and gas industry intensity metrics and targets, highlighting differences in their methodology (i.e., applicability, calculation method, and the use of emission allocation). Formulas using emission allocation are considered oil and gas-based intensities, even if resulting metrics may only apply to either oil or gas.

Metric	Protocol, Jurisdiction	Formula	Applicable To	GHG(s) Considered	Units	Target	Notes
Gas-Based Intensity	OGCI[21]	$\frac{V_{CH_4,emit}}{V_{gas,mark.}}$	All Production	CH_4	%	0.20	OGDC aligned with this target[8]
	U.S. WEC[22]					0.20	For sites conserving gas; if none, the alternate target must be met (see below)
	China[5]					0.25	
	Sk., Canada[11]	$\frac{m_{CO_2e,emit}}{m_{CO_2e,possible}}$ (see note*)	Oil Sites Only	CH_4, CO_2		4 – 36	Large operators only. Vent/fugitives and flaring CO_2e*. Different targets by year and region.
	Sk., Canada[12]			CH_4		5 – 20	As above but considering only vent/fugitive CO_2e emissions.
	OGCI[21]	$\frac{m_{CO_2e,emit}}{E_{mark.}}$		CH_4, CO_2	kg_{CO2e}/BOE	NA	100-yr GWP CO_2e values.

Oil and Gas-Based Intensity	U.S. WEC[22]	$\frac{m_{CH_4,emit}}{E_{mark.}}$	All Production	CH_4	t_{CH4}/million BOE	10	Oil-only exemption to gas-based U.S. WEC metric.
	Co., U.S.[19]	$\frac{m_{CO_2e,emit}}{E}$		CH_4, CO_2, N_2O	t_{CO2e}/kBOE	34.4 – 6.8	Targets vary by operator size and year
	MiQ[17]	$\frac{m_{CH_4,emit}}{E_{mark.}}$		CH_4	g_{CH4}/BOE	Various	Graded for intensities below 2000 g_{CH4}/BOE. For gas-oil ratio below ~9000
	NGSI[13]	$\frac{x_{gas} \cdot V_{CH_4,emit}}{V_{CH_4,mark.}}$	Natural Gas Only, using Emission Allocation	CH_4	%	NA	
	ONE Future[15]	$\frac{x_{gas} \cdot V_{CH_4,emit}}{V_{gas}}$				0.28	Company target per marketed methane; national 1% target per produced methane
	GTI Veritas[14]	$\frac{x_{gas} \cdot V_{CH_4,emit}}{V_{CH_4,mark.}}$				NA	
	MiQ[16]	$\frac{x_{gas} \cdot m_{CH_4,emit}}{m_{CH_4,mark.}}$				Various	Graded for intensities below 2%. Gas-only sources are added to the energy-allocated emissions.
	MiQ[18]	$\frac{x_{gas\ or\ oil} \cdot m_{CO_2e,emit}}{E_{mark.\ gas\ or\ oil}}$	All Production, using Emission Allocation	CH_4, CO_2, N_2O	g_{CO2e}/million Btu or g_{CO2e}/bbl	NA	Allows the use of 20- or 100-year GWP CO_2e values.

Where x is the energy fraction of a product ("gas" or "oil") to the combined production; m is mass, V is volume, E is energy – each denoted with specific subscripts for "marketed" or "produced" amounts of methane (CH_4), gas, or combined oil and gas where not specified (e.g., $E_{mark.}$).
*Possible CO_2e emissions are a proxy for gas production, converted using published emission factors[23,24]. Similarly, emitted CO_2e is calculated from these emission factors and reported whole gas volumes.

2.1. Gas-Based Intensity

Gas-based intensities relate emissions only to natural gas production, evaluating the gas-handling performance of the producer/region. The most common such metric is the "methane loss rate" (MLR), which is the ratio of emitted methane to produced (or marketed) methane, expressed in [%] as either a mass or volumetric ratio. Studies and recently collected measurement-based data have found a wide range of methane loss rates at the regional level: <1% to 100% (per produced/gross gas production). At the national level for the U.S., Canada, and Mexico, respectively, loss rates of 2.3-3%[25,26], 2.1%[27], and 4.7%[28] have been observed. However, questions often arise about the comparability between gas-only and mixed oil and gas production regions. Indeed, more oil-focused production tends to have higher methane loss rates – see for example, the ~20% loss rates in oil-focused Saskatchewan (up to 100% in the Lloydminster region[29]) vs. ~0.4% in gas-focused British Columbia, Canada[27]. Nevertheless, these metrics yield intelligible values about the gas-handling performance of any hydrocarbon production region and have become an important metric for international commitments (OGCI/OGDC). However, the ability to apply progressively updated methane loss rates downstream is only possible for natural gas, not oil products.

A less common variant of the gas-based metrics is a CO_2e emission intensity, where CO_2e emissions are normalized by *potential* CO_2e emissions (i.e., if all produced gas were emitted). Initially used in Saskatchewan[11], Canada, this approach has since been replaced with a calculation effectively equal to a methane loss rate[12]. The initial approach proved challenging because it required estimates of emissions from flaring and combustion in engines, which remain highly uncertain, and because the use of only a 100-year time horizon for CO_2e risks introducing confusion about temporal trade-offs[30]. Aside from the challenges of this CO_2e intensity, the key variants in gas-based intensities are generally related to the choice of normalizing factor for the methane emission numerator.

2.1.1. Calculation Variants

Normalizing by Produced or Marketed Amounts

Methane emissions can be normalized by produced (gross) or marketed (net) gas/methane amounts. When benchmarked against produced amounts, a loss rate suggests that X% of the gas produced at the wellhead is lost to the atmosphere. This value is most readily used by industry and regulators because it describes the fraction of gas still available for mitigation or conservation. When benchmarked against marketed methane (i.e., produced amounts minus any methane lost, flared, or burned in engines), a loss rate suggests that for each amount of gas delivered further down the supply chain, another X% was lost to the atmosphere. This value might be more useful to purchasers/consumers of the resulting gas, but it cannot be applied to all sites since not all have gas sent to sales. (To address this issue, the U.S. Waste Emission Charge required an energy intensity threshold be met for non-gas conserving sites). An intensity benchmarked against marketed amounts is always higher than or equal to those using produced amounts. While some jurisdictions publish both marketed and produced natural gas volumes, this is not uniformly true globally, with marketed production more likely to be available.

Normalizing by Methane or Whole Gas

While many gas-based intensities normalize methane emitted by *methane volumes*, the OGCI and U.S. Waste Emissions Charge loss rates instead normalize by *whole gas volumes*. This was done for simplicity – it does not require any knowledge of gas composition. However, this means that loss rates per whole gas are essentially always smaller than a typical methane loss rate. Although the difference between them is minimal for high-methane content gas, lower-methane gas—for example, 50% methane—will report a per-whole-gas loss rate that is half the methane-to-methane loss rate. Normalizing by methane amounts is therefore preferable since it provides consistent loss rates across differing gas compositions.

2.2. Oil & Gas-Based Intensity

Emissions intensity can also be calculated considering both oil and gas, here referred to as "energy intensity" (EI). Most often expressed as a mass of methane per unit of hydrocarbon energy produced/marketed, e.g., g_{CH4} per MJ of energy or barrel of oil equivalent (BOE). This intensity yields less intuitive values than the gas-only metrics, but it has the benefit of being definable even when no gas is sent to market. And since crude oil and natural gas are both fundamentally energy products – and often co-produced – emissions per unit energy is a useful measure of the trade-off of climate harm to end product, even if it mixes two distinct types of hydrocarbons. More consistently than gas-only metrics, energy intensities can be transferred and updated as products travel through their respective supply chains. These metrics can also consider non-methane greenhouse gas emissions, however, these approaches are impacted by the CO_2e time horizon selected, which risks undervaluing methane's net radiative forcing. And while oil & gas-based metrics can also be normalized by marketed or produced amounts, the key variations in their calculation are the choice of units and the assumed energy content of the oil and gas produced.

2.2.1. Calculation Variants

Units

The energy intensity (units of [g_{CH4}/MJ] or [g_{CH4}/BOE]) can be transformed into an energy loss rate, with units of [MJ/MJ] and therefore also [%], since the energy content of the emitted methane is known. While this formulation uses conveniently universal units, it risks being confused with gas-only intensities, which are almost always expressed as a percentage. Further, this energy loss rate formulation underestimates the true energy loss rate since lost energy from emitted non-methane gas is typically omitted. Finally, this energy loss rate is not as a direct statement about methane performance as the methane loss rate since it also depends

on the gas-oil production mix (see Sect. 3.1), which makes it more difficult to incentivize methane mitigation clearly.

Another variation of the energy intensity expresses this oil and gas denominator as barrels of oil equivalent (BOE). While this reports emissions per unit volume, the BOE is in effect a statement of energy. A barrel of oil in the U.S., for example, is 5.8 million BTU (~6120 MJ)[31] and there are 6000 cubic feet (~170 m^3) of natural gas per BOE[10]. However, since crude oil and natural gas both vary in energy content, generic BOE conversions risk neglecting energy content differences in both products and increasing the uncertainty in these metrics.

Energy Content Assumptions
Knowledge of crude oil and natural gas energy contents is required to calculate the energy intensity. In the U.S., oil and gas heating values are typically gleaned from the American Petroleum Institute (API)[13–16,31], but it is unclear whether such data would be more broadly applicable; alternatively, energy content for crude oil can be estimated knowing the oil density[32,33]. Interestingly, the API notes that while higher heating values (HHV) are common in Canada and the U.S., lower heating values (LHV) are preferred elsewhere. While the differences tend to be small (HHV is often only 5-10% higher than LHV), this can add uncertainty to international comparison if the two standards are mixed.

2.2.2. Allocation Methods

Methane emissions can be readily assigned to the marketed product for a production site yielding only crude oil or natural gas, but production wells often handle mixtures of marketable hydrocarbons. For mixed production, detailed allocation of emissions to each product would need to be done in a transparent and empirical fashion, often requiring data that is not uniformly available. Instead, simple emission allocations can be done on the basis of relative energy content, mass, or value[34], although energy-based allocation is most common since these hydrocarbon products are primarily energy carriers, and prices are highly variable[34]. For example, if 60% of marketed energy comes from natural gas, 60% of the methane emissions for that region are attributed to the gas. The most common such allocation protocol was proposed by the Natural Gas Sustainability Initiative (NGSI)[13], but variations on this method have since emerged[14–16]. The NGSI method allocates emissions to natural gas based on its fraction of marketed energy, and dividing by marketed methane amounts, calculates an intensity in percentage units (see Table 1), however, this intensity is often mistaken for a methane loss rate.

3. Results

3.1. Relationship between Gas-only and Oil & Gas Metrics

At our assumed oil and gas properties (Sect. 5), Figure 1 shows how the methane loss rate (gas-only metric) and energy intensity (oil and gas metric) are related through the gas-oil ratio. While other factors will impact this relationship (e.g., methane content of the gas, differences in energy content of oil and/or gas), these variations will have only a minor impact relative to the ~1000:1 difference in volumetric heating value between oil and gas. The figure also presents alternate forms of energy intensity: the NGSI methane intensity and the energy loss rate. The absolute values of these two alternate forms are similar, but the NGSI intensity is approximately 50% higher than the energy loss rate, because of a factor of $HHV_{v,gas}/(HHV_{v,CH_4} \times VF_{CH_4})$ between them, where VF_{CH_4} is the assumed methane volume fraction of the gas and HHV_v are volumetric heating values for whole gas and methane. Nevertheless, this demonstrates that the different oil and gas-based metrics are functionally equivalent despite their different formulation, interpretation, and absolute values.

Importantly, Figure 1 shows that at a given methane loss rate, oil-focused production regions (i.e., low gas-oil ratio) will have a lower energy intensity than gas-focused production. This is sensible considering an oil region with 5% methane loss rate loses a much smaller fraction of its produced energy than a gas-only region with the same loss rate. Even though gas-focused regions tend to have lower methane loss rates because gas is their primary product, oil-focused production could still yield a lower energy intensity. This could lead to the erroneous conclusion that mixed oil and gas production is less methane-intensive than gas-only, which is not necessarily true. Under a methane intensity-based import standard, this would lead to a preferential consumption of products from the mixed oil and gas production region over gas-only.

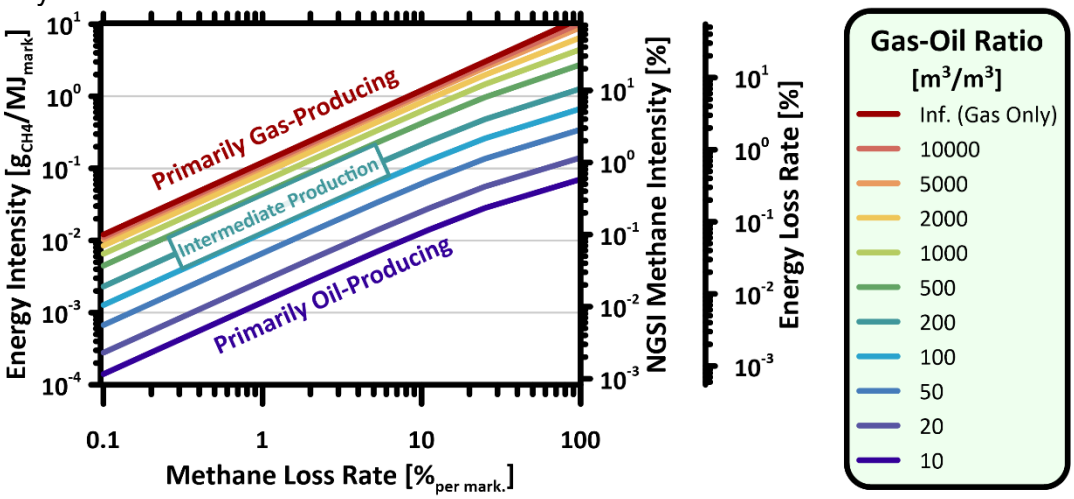


Figure 1. Comparison of methane loss rate and energy intensity (and its alternate form as an energy loss rate) for some hypothetical oil and gas production region, with gas-oil ratios (GOR) as noted. Note that a GOR above ~1750 is generally considered a gas field[35].

3.2. Producer-Level Comparisons (Reported Emissions)

In Figure 2, we compare the annual producer-level emission intensities by well type in 2021 for Alberta and Saskatchewan, Canada, per produced amounts. Figure 2a shows that crude/heavy crude oil producers can have lower energy intensity than gas producers even if the latter have lower methane loss rates. When we compare the relative ranking (Figure 2b and c; intensity ranked from lowest (1) to highest), gas producers tend to rank better under methane loss rates, but perform comparatively worse under energy intensity.

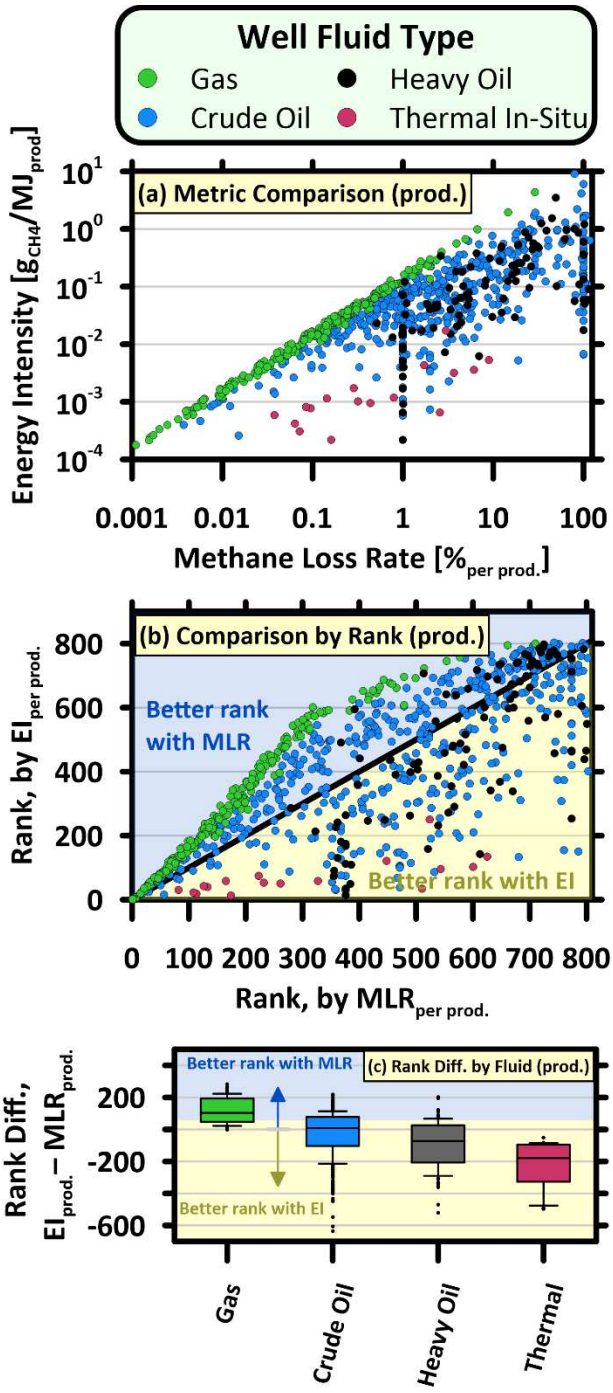


Figure 2. Comparison of methane loss rates (MLR) and energy intensities (EI) in Alberta and Saskatchewan, Canada, based on reported emissions and production. Each dot represents a producer / well type combination, meaning a single producer may appear more than once if they have multiple types of producing wells. The figure shows (a) absolute metric comparison, (b) rank comparison, and (c) the rank difference between metrics. A better rank (i.e., closer to 1) indicates lower intensity. This figure is reproduced as SI Fig. S1 for marketed amounts.

Looking at the absolute ranking of producers with different well types under either intensity metric (Figure 3), we see the trade-offs between metrics more clearly. For example, Figure 3a shows that using methane loss rate, the vast majority of gas producers rank better than crude and heavy oil producers; meanwhile, using energy intensity, there is considerably more overlap. This is important for understanding which operators are impacted by an intensity threshold set in

one metric versus the other. If a threshold is set as a methane loss rate, most oil producers are impacted before any gas producers; if set as an energy intensity, a mix of oil and gas producers are affected. However, it is important to remember that both metrics provide useful information that is not readily gleaned from the other: methane loss rates assess gas-handling performance directly, and the energy intensity evaluates more general resource production efficiency.

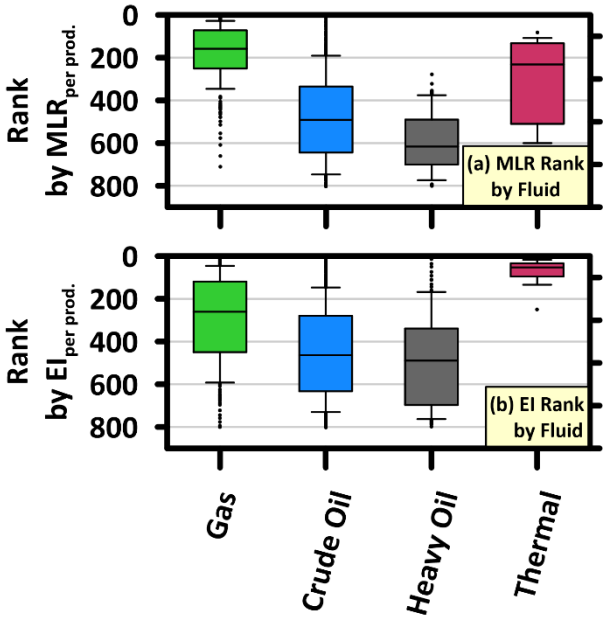


Figure 3. Absolute ranking of oil and gas well type producers in Alberta and Saskatchewan for (a) methane loss rates (MLR) and (b) energy intensities (EI). While gas types are mostly better ranked versus oil in methane loss rate, there is much more overlap in rankings under energy intensities. Box edges represent the 25th and 75th percentile; whiskers the 10th and 90th percentile.

Finally, we compared the ranking of producers by each metric normalized by marketed or produced gas amounts (SI Fig. S2). This shows that the relative ranking of producers using the energy intensity changes very little between marketed and produced denominators, suggesting that estimating marketed amounts from produced amounts (or vice versa) may be a reasonable approximation. The same cannot be said for the methane loss rate, where the oil-producing sites with little to no marketed production are pushed to comparatively worse rankings versus their intensity per produced amounts.

3.3. Regional Comparisons (Measured Emissions)

The differences in intensity metrics observed in the previous section, where the methane loss rate tends to rank gas sites better and the energy intensity more favourably ranks oil sites, can also be seen at the regional level in Canada and the United States (Figure 4). Plotting the intensities calculated from reported production and aerial emissions measurement data[36–39], we see that oil-focused regions (i.e., low gas-oil ratio) receive a better rank from energy intensities.

While the five highest intensity regions are the same using either metric, it is notable that their positions reverse between metrics. Graded by methane loss rate, two oil-focused regions (Saskatchewan, Uinta) have the highest intensities, followed by three gas-focused regions; graded by energy intensity, the three gas regions (Piceance, Greater Green River, Fayetteville) have higher intensities than the oil regions. At the other end, gas-focused British Columbia has the lowest intensity in both metrics, but the oil-focused Bakken ranks 2nd by energy intensity yet 10th by methane loss rate.

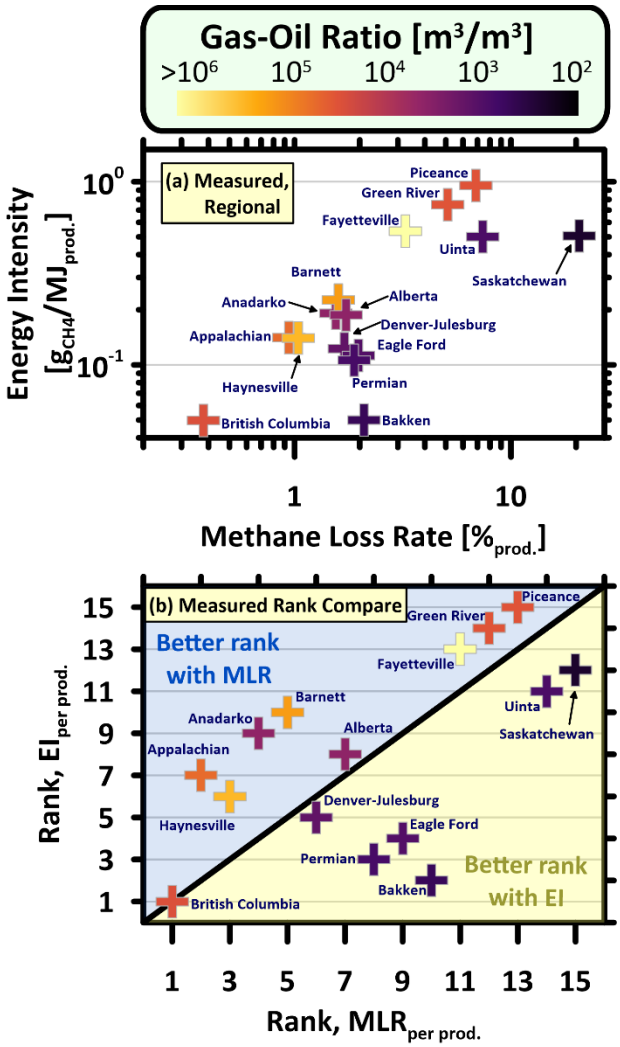


Figure 4. (a) Regional methane intensities and (b) rank comparison for Canada and the United States based on Bridger Photonics and MethaneAIR studies and reported production. Importantly, this shows that energy intensity tends to rank more oil-focused regions better also at the regional level.

3.4. Absolute Production Dependence

We found an interesting relationship between methane intensities and absolute production amounts in both the producer-reported emissions and regional aircraft measurements. Figure 5 shows that the methane loss rate tends to decrease with increased absolute production. This perhaps points to the effect of low-producing and/or older wells generally having higher emission intensities[40,41] related to sites falling into disrepair and/or because production and emissions decline at different rates, resulting in different intensities over time[40]. It may also be because gas-focused regions have more effective gas conservation equipment. In any case, this consideration might be useful in developing emission intensity thresholds for regions and operators – more productive regions with a higher degree of infrastructure integration might tend to have lower intensities.

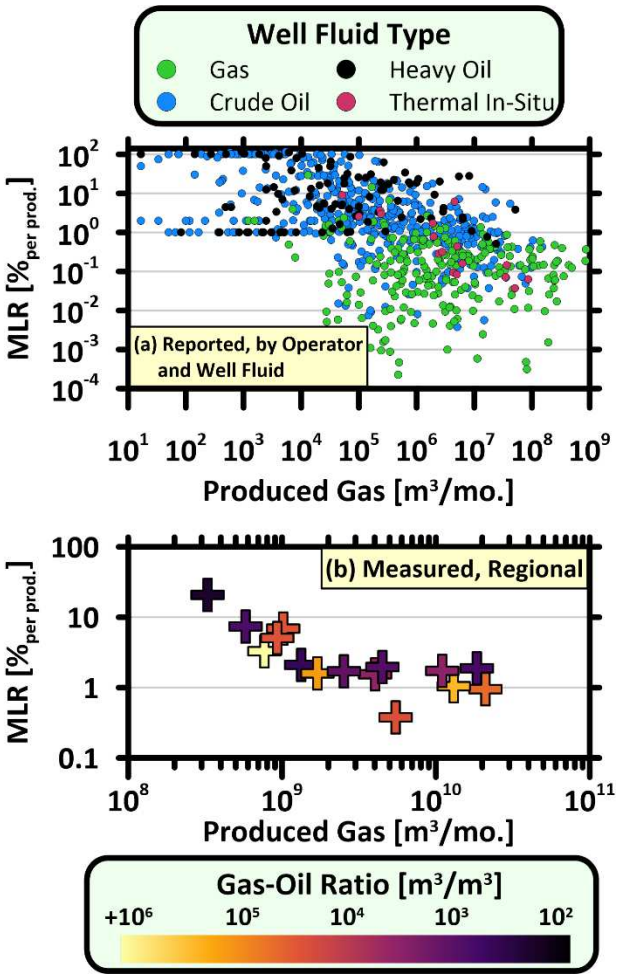


Figure 5. Methane loss rates tend to be lower for (a) producers and (b) regions with higher absolute gas production.

3.5. Allocation procedures do not change the energy intensity

While the allocation of upstream emissions has been recommended for differentiation of oil and natural gas products, current formulations offer limited assistance. When an energy-based emission allocation is used to calculate an *energy intensity*, it yields the trivial solution that oil and natural gas have the same intensity. This is evident since a ratio of, for example, 10% of emissions allocated to 10% of produced energy is the same as the ratio of 90% of emissions allocated to 90% of energy, regardless of the respective hydrocarbon types.

Meanwhile, the NGSI method, which allocates methane emissions to gas on an energy-basis and divides by marketed methane, yields two notable results: (1) an intensity cannot be defined for oil (there is no marketed methane in oil), and (2) the resulting NGSI intensity for natural gas is proportional to the energy intensity of the combined oil and gas. This latter point may not be immediately clear, but consider that the energy intensity for gas is $x_{gas} \cdot m_{CH_4,emit}/E_{gas,mark}$, where x is the energy fraction of the marketed gas; the NSGI intensity, meanwhile, is $x_{gas} \cdot V_{CH_4,emit}/V_{CH_4,mark}$. The marketed gas energy denominator of the former can be transformed into the volume of marketed methane by multiplying by $VF_{CH_4}/HHV_{v,gas}$.

4. Discussion

4.1. One metric is not sufficient, but both types provide useful information

One metric is insufficient to characterize oil and gas emission intensity. As shown in Figure 1, many combinations of GOR and methane loss rate yield the same energy intensity, and different producers can have the same methane loss rate across a wide range of GOR, yielding different energy intensities. Ultimately, a combination of gas-only (e.g., methane loss rate) and oil and gas-based (e.g., energy intensity) metrics is needed to better characterize methane performance.

Gas-only metrics are necessary because they evaluate a producer/region's gas-handling performance—this is a direct statement about methane mitigation performance, and about how much methane is left to mitigate relative to production. While the methane loss rate is intuitive, used alone, it faces difficulty in describing intensities for the diverse oil and gas industry, primarily because oil-focused production regions tend to have higher loss rates than gas-focused ones.

However, an oil and gas-based metric also provides useful information. Since fossil fuels are fundamentally energy products, knowing the emissions per unit energy tells us about the trade-off between emissions and salable product. That said, if used alone, this metric does not give a clear indication of methane performance since it also depends on the gas-oil ratio.

4.2. Report both Metrics

We recommend that both a gas-only and an oil and gas-based intensity metric be reported to provide a fuller picture of methane emissions performance. Among the available options, we recommend that two specific variants be reported:

(1) methane loss rate per marketed methane [%], and,
(2) energy intensity per marketed oil and gas [g_{CH4}/MJ].

Using methane loss rate per marketed methane gives more comparable results to methane-to-gas loss rates, and marketed amounts are more often available. (In this study, where no gas is marketed or loss rates exceeded 100%, we assigned 100% loss rates). Meanwhile, an energy intensity per marketed amount is desirable because it gives the best indication of relative climate impacts per salable products to buyers. Even if only produced amounts are available, marketed amounts of gas can be estimated knowing methane emissions (and perhaps flaring and on-site gas use volumes). Indeed, our operator-level case study in Canada showed that differences in energy intensity rankings between produced or marketed amounts were minimal (SI Fig. S2), suggesting that an approximation of marketed volumes would not impart significant bias in energy intensity.

4.3. Policy Consideration

This dual-metric approach offers a balanced and flexible framework for policy design. Reporting both metrics enables regulators to account for production mix differences among operators/regions, allowing better targeting of either gas-handling (via the methane loss rate) or broader resource efficiency (via the energy intensity). This has already been accomplished in some sense by the U.S. Waste Emission Charge, which imposed a maximum methane loss rate on gas-conserving operators (0.2%), or a maximum energy intensity (10 t_{CH4} per million BOE) on those without gas conservation, helping to incentivize oil-only producers to capture wasted gas. Alternatively, the dual-metric approach could set primary and backstop emission intensity

thresholds. For example, an energy intensity might be set for an oil-focused region, but a backstop methane loss rate limit could be set to disincentivize the highest loss rates at certain types of facilities. The dual-metric reporting provides a direct solution for domestic policy-makers to incentivize effective methane mitigation for oil and gas produced within their own jurisdiction, and a similar approach may be useful when applied to international oil and gas markets.

The EU's methane regulation, for example, requires that maximum methane intensity levels be set separately for crude oil and natural gas. The analysis presented in this study provides insight on how to achieve this. Emission thresholds—or intensity levels—may be set for natural gas and crude oil by first creating definitions of gas- or oil-focused production. This can be done empirically using basin-level GOR data. A maximum methane loss rate may then be set for the gas-focused GOR bracket; analogously, a maximum energy intensity can be set for both natural gas and oil produced from the oil-focused GOR bracket. However, these intensity thresholds must be set to achieve the objectives of the EU's methane regulation[20] (e.g., absolute global methane reductions, EU competitiveness and energy security), which might necessitate modelling the influence of different intensity thresholds (and potentially also GOR bracket definitions).

5. Methods

To explore how different methane intensity metrics grade producer performance, we calculated intensities for a hypothetical production region of varying gas-oil ratios, and for actual regional and operator-level production in the U.S. and Canada. We compared gas-only and oil and gas-based intensities using the "methane loss rate" (MLR) [%] and "energy intensity" [g_{CH4}/MJ]. The methane loss rate considers methane mass emitted per produced (gross) or marketed (net) methane mass, distinguishing between them as: [$\%_{per\ prod.}$] vs. [$\%_{per\ mark.}$]. For the energy intensity, we use higher heating values for hydrocarbon products, and again distinguish between produced or marketed energy as: [$g_{CH4}/MJ_{prod.}$] vs. [$g_{CH4}/MJ_{mark.}$].

For theoretical intensity calculations, we assumed the "generic" gas composition from the American Petroleum Institute[31] (80% methane, 15% ethane, 5% propane, by volume). We estimated the gas had a higher heating value of ~44.9 MJ/m^3. For crude oil properties, we assumed a light crude oil with API gravity of 35°. Similar to Brandt et al.[33], we used crude oil heating values from Schmidt[32], suggesting a higher heating value of 35,720 MJ/m^3. We considered a range of gas-oil ratios in production, from 10 m^3/m^3 to infinity (i.e., gas-only).

We calculated annual, operator-level intensities for Alberta and Saskatchewan, Canada, from public volumetric emissions/production data[42,43] for 2021. We augmented industry data from previous studies[44,45] that grouped reported emissions/production by operator and well type (and linked to gas properties[46,47]), with average oil properties[48], allowing for regional, producer-and well-type intensities to be calculated. Well type (crude oil, gas, thermal in-situ, and non-thermal heavy) was gleaned from the production facility types they were linked to. Well type serves as a proxy for key production characteristics—such as gas-oil ratio or processing requirements—that can strongly influence emissions and resulting intensities. In addition to the reported leak/vented emissions, the data also included flared and fuel use volumes. We assumed that flaring had a 98% combustion efficiency and that fuel use in engines had a 99% efficiency. Produced gas volumes were reported, and we calculated marketed gas production as gross gas minus gas vented/leaked, flared, and burned in engines. In this analysis, we aggregated sites by province, producer, *and* well type. While producer-level aggregation might combine production across well

types, calculating intensities by well type better illustrates the tendencies of different intensity metrics explored in Sect. 3.

Regional, annual emission intensities for Canadian provinces (2021) and U.S. basins (2023) were also calculated, using aircraft measurement-based studies using Bridger Photonics[37–39] and MethaneAIR[36] data, respectively. Canadian production data for the measured periods were accessed from provincial databases in Canada[42,43,49], and from Enverus for the U.S. Average methane content was assumed to be 85.7%, 86.6%, and 79.5% in B.C., Alberta, and Saskatchewan, respectively; B.C. values were based on federal government estimates for gas production sites[50] and Alberta and Saskatchewan were calculated as a gas production-weighted average of methane volume fractions from the producer-level data. For the U.S., methane content was assumed according to SI Table S1, ranging from 47% (Bakken) to 93% (Anadarko). In all cases, we assumed that the remaining gas proportions were reflective of the API “generic” gas content – three-quarters of non-methane gas was ethane, and one-quarter was propane – allowing us to estimate heating values.

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Data Availability
Industry-reported data for Alberta and Saskatchewan were accessed through provincial databases (https://www.petrinex.ca/Pages/default.aspx).

Author Contributions
Contributed to the conception and design: SPS, DX, DZA
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Competing Interests
The authors declare no competing interests.

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