POLICY FORUM

ENERGY AND CLIMATE

Global carbon intensity of crude oil production

New data enable targeted policy to lessen GHG emissions

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Producing, transporting, and refining crude oil into fuels such as gasoline and diesel accounts for ~15 to 40% of the "well-to-wheels" life-cycle greenhouse gas (GHG) emissions of transport fuels (*1*). Reducing emissions from petroleum production is of particular importance, as current transport fleets are almost entirely dependent on liquid petroleum products, and many uses of petroleum have limited prospects for near-term substitution (e.g., air travel). Better understanding of crude oil GHG emissions can help to quantify the benefits of alternative fuels and identify the most cost-effective opportunities for oil-sector emissions reductions (*2*). Yet, while regulations are beginning to address petroleum sector GHG emissions (*3*–*5*), and private investors are beginning to consider climate-related risk in oil investments (*6*), such efforts have generally struggled with methodological and data challenges. First, no single method exists for measuring the carbon intensity (CI) of oils. Second, there is a lack of comprehensive geographically rich datasets that would allow evaluation and monitoring of life-cycle emissions from oils. We have previously worked to address the first challenge by developing open-source oil-sector CI modeling tools [OPGEE (*7*, *8*), supplementary materials (SM) 1.1]. In this Policy Forum, we address the second challenge by using these tools to model well-to-refinery CI of all major active oil fields globally—and to identify major drivers of these emissions.

We estimate emissions in 2015 from 8966 on-stream oil fields in 90 countries (SM 1.4.4). These oil fields represent ~98% of 2015 global crude oil and condensate production. This analysis includes all major resource classes (e.g., onshore/offshore and conventional/unconventional) and accounts for GHG emissions from exploration, drilling and development, production and extraction, surface processing, and transport to the refinery inlet (collectively called "upstream" hereafter). These results are based on data from nearly 800 references, including government sources, scientific literature, and public technical reports (SM 1.4.1, 1.4.4, and table S17). Proprietary databases are used to supplement these data when information is unavailable in the public domain (generally for small oil fields). The latest Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potential (AR5/GWP100) factors are used in this work (SM 1.2.1).

COUNTRY-LEVEL UPSTREAM CARBON INTENSITY

Figure 1 presents the first upstream country-level volume-weighted-average CI estimates and their corresponding error bars (see fig. S22 for the global upstream CI map). Error bars are computed by using probabilistic uncertainty analysis solely associated with missing input data (SM 1.7 and 2.4). The CI estimates of some countries with poor data quality (e.g., Russia) in Fig. 1 are more uncertain (SM 1.4.6 and 2.3).

The global volume-weighted-average upstream CI estimate—shown by the vertical dashed line in Fig. 1—is 10.3 g CO_2equivalents (CO_2eq.)/megajoule (MJ) crude oil (+6.7 and –1.7), with country-level intensities ranging from 3.3 (Denmark) to 20.3 (Algeria) g CO_2eq./MJ. Carbon dioxide and methane contribute on average 65% and 34% of total CO_2eq. emissions, respectively (SM 2.2). The total petroleum well-to-refinery GHG emissions in 2015 are estimated to be ~1.7 Gt CO_2eq., ~5% of total 2015 global fuel combustion GHG emissions. This estimate of total emissions is ~42% higher than an industry-wide scaling of an estimate for 2015 from the International Association of Oil and Gas Producers (based on datasets comprising 28% of global production with uneven geographical coverage). See SM 3 for exploration of the differences between our analyses.

Emissions in Fig. 1 can vary substantially over time (*9*), but time-series data are generally missing on a global basis and so are not explored here. In general, oil production declines with oil field depletion but is also accompanied by a substantial increase in per-MJ GHG emissions due to use of enhanced recovery practices. Other factors (e.g., oil price, geopolitics) could also affect oil production and thus the temporal CI (*9*).

Gas flaring (burning) practices have a considerable influence on the CI. If not economically salable, this gas is either flared, reinjected, or vented (directly emitting methane). The estimated share of flaring emissions in the global volume-weighted-average upstream CI is 22% (i.e., 2.3 g CO_2eq./MJ). Flaring data are not widely reported by governments or companies, so for most regions, our analysis relies on satellite-estimated volumes computed using nighttime radiometry (SM 1.2.4 and 1.4.3.18). Some important conventional crude oil producers with above-average global CI, such as Algeria, Iraq, Nigeria, Iran, and the United States, are also among the top 10 countries in flaring observed via satellite. The contributions of routine flaring to the total volume-weighted-average CI of these countries are estimated herein to be ~41, 40, 36, 21, and 18%, respectively. Variability between flaring data sources results in greater uncertainty for countries with high contribution of flaring to their CI. Figure S27 shows that gas venting instead of flaring increases the estimated GHG emissions substantially (SM 1.2.4 and 2.6). However, currently there is no reliable remote-sensing technology for measuring gas venting.

As the major global producers of unconventional heavy oils, Venezuela and Canada have high country-level CI. This is due to energy- and CO_2-intensive heavy oil extraction and upgrading. Enhanced oil recovery by steam flooding contributes to high CI in other locations, such as Indonesia, Oman, and California (USA).

Although some giant North Sea offshore fields have shown rapidly increasing per-bbl (barrel) emissions due to depletion (*9*), they have low upstream GHG intensities when compared to many other global oil fields. This is in part due to stringent regulations on gas processing and handling systems and renewable electric-power-from-shore initiatives. Saudi Arabia is the largest global oil producer but has a small number of extremely large and productive reservoirs. The country has low per-barrel gas flaring rates and low wa-

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ter production—resulting in less mass lifted per unit of oil produced and less energy used for fluid separation, handling, treatment, and reinjection—and thus contributing to low CI.

FIELD-LEVEL UPSTREAM CARBON INTENSITY

Figure 2 shows a global field-level CI curve for our 8966 fields (sorted cumulatively). This illustrates the CI heterogeneity of global crudes (SM fig. S19 and Results Data Excel file). Fields in the highest 5th percentile emit more than twice as much as the median field. Upstream mitigation measures should focus on fields in the upper end of the CI curve.

Although crude density (requiring thermal extraction methods) and flaring are key determinants of a high CI (SM 1.5), the second figure shows that flaring is the more prevalent driver: For the highest CI quartile (i.e., >1.2 g CO_2eq./MJ) in this figure, 51% of crude volume comes from high flare fields (yellow, red), while 18% comes from heavy oil fields (yellow, blue). Only 4 and 9% of crude volumes from the rest of the sample (i.e., ≤11.2 g CO_2eq./MJ) come from high flare and heavy oil fields, respectively.

The cumulative CI curve uncertainty due to missing input data is computed via a Monte Carlo simulation and presented in fig. S25 (SM 1.7 and 2.4).

POLICY IMPLICATIONS

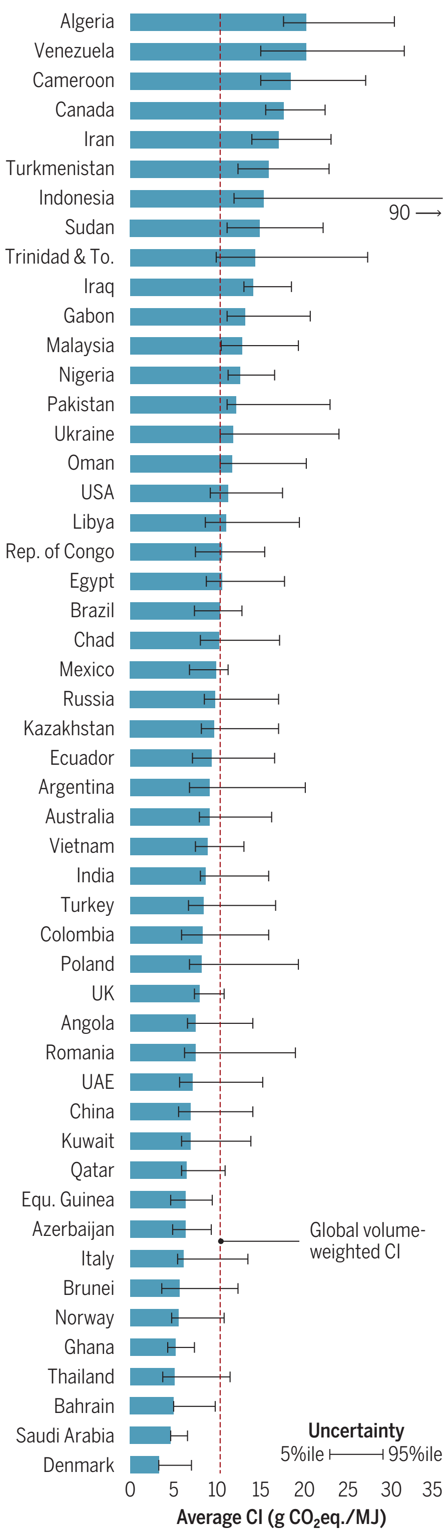
Although oil alternatives like electric vehicles are rapidly growing, society is likely to use large volumes of oil in the coming decades (*10*); thus, mitigation of crude oil CI is key. Our tools and dataset allow for improved analysis of the benefits of emissions mitigation policies. We highlight three broad strategies to reduce GHG impacts: (i) resource management, (ii) resource prioritization, and (iii) innovative technologies.

Performance-oriented fuel quality standard programs based on life-cycle analysis models have been implemented successfully and have created new regional market drivers (e.g. in California, British Columbia, the European Union). Relying on market forces and credit/debit mechanisms, these fuel-agnostic policies do not dictate specific technologies to reduce the emissions but rather encourage innovation to comply with the quality mandates. To achieve greater impacts, such regional fuel standard policies are emerging nationally (e.g., Canada's Clean Fuel Standard) and, subsequently, worldwide. These regulations should recognize the climate impact heterogeneity of different crude oils (see the second figure) to reward improved production practices with clear per-barrel incentives for the lowest CI producers (*10*).

The current lack of transparency about global oil operations makes this type of

National volume-weighted-average crude oil upstream GHG intensities (2015)

The global volume-weighted CI estimate is shown by the dashed line (~10.3 g CO_2eq./MJ). Error bars reflect 5th to 95th percentiles of Monte Carlo simulation to explore the uncertainty associated with missing input data (see SM 1.7 and 2.4).



analysis particularly challenging. Labor-intensive data gathering (as undertaken here) still results in large uncertainty in emissions estimates (SM 2.3 and 2.4). Thus, it is important to adopt policies to make data from oil and gas operations publicly available. If done correctly, these data can be released without affecting competitiveness of enterprises. Countries including Norway, Canada, the United Kingdom, Denmark, and Nigeria have led in this respect. As countries pledge their commitments to reduce country-level GHG emissions and transparent reporting under the Paris Agreement, it is essential for energy-intensive industries (such as the oil and gas sector) to regularly report their annual carbon footprints. New industry efforts such as the Oil and Gas Climate Initiative are beginning to tackle this challenge.

CI curves for four hypothetical GHG mitigation case studies are shown in fig. S26 (SM 1.2.2 and 2.5). Two "no routine flaring" case studies restrict the flare-to-oil ratio (FOR) to be no higher than the global 5th and 25th percentiles. A fugitive emissions reduction scenario sets fugitive and venting emissions to be 0.2 g CO_2eq./MJ, approximately the volume-weighted average from Norwegian oil fields in 2015 (SM 1.2.2). Cases with no routine flaring (moderate and extreme) have global volume-weighted-average CI reduced from 10.3 (current world) to 8.7 and 8.3 g CO_2eq./MJ. Achieving the fugitive and venting reduction scenario results in 7.9 g CO_2eq./MJ. These case studies mitigate 15% [262 megatons (Mt) CO_2eq.], 19% (332 Mt CO_2eq.), and 23% (397 Mt CO_2eq.) of the current annual global upstream estimate, respectively. A fourth case study, including both stringent flaring reduction and minimal fugitive and venting emissions, reduces the global average to 5.8 g CO_2eq./MJ and results in ~43% (~743 Mt CO_2eq.) annual CI reduction.

A simple calculation suggests that upstream emissions from oil extraction can materially affect cumulative emissions caps. Assume a reduction in the current global volume-weighted-average CI to the current 25th percentile (reducing emissions by ~3 g CO_2eq./MJ). Such reductions would be possible using the mitigation case studies from fig. S26. Given that a typical barrel of crude oil yields ~6000 MJ, this would result in ~18 kg CO_2eq./bbl emissions reduction. Also note that IPCC scenarios—even with aggressive adoption of alternative fuels used for transport—still result in projected cumulative oil consumption of >1 trillion barrels in the 21st century. Thus, at least 18 metric gigatons (Gt) CO_2eq. (~12 Gt as CO_2 and ~6 Gt as CH_4) could be saved over the century by mitigating oil-sector emissions through wise resource choices and improved gas management practices. Considering additional mitigation op-

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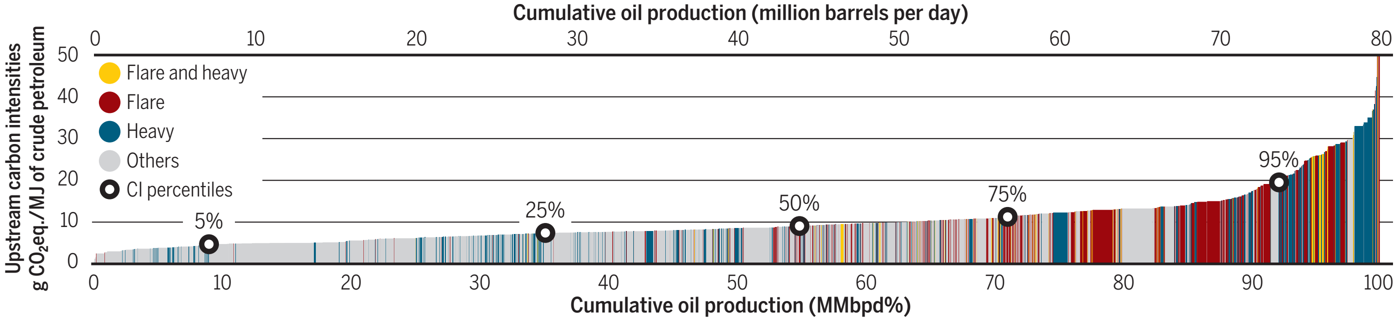
Global field-level upstream carbon intensity supply curve (2015)

Contribution of high flaring (labeled "Flare" with FOR >75th percentile of all fields) and oil density (labeled "Heavy" with API gravity ≤22°). Bar width reflects the oil production of a particular field in 2015. Global GHG intensity percentiles (5%, 25%, 50%, 75%, 95%) are 4.7, 7.3, 9.1, 11.2, and 19.5 g CO_2eq./MJ crude oil, respectively.



portunities across the crude oil supply chain (e.g., improved refining), 18 Gt is likely an underestimate; other studies have estimated up to 50 Gt CO_2eq. reduction potential (*10*). For a >66% chance to keep global average temperature increases below 2°C, a total of ~800 Gt CO_2 can be emitted from 2017 forward (*11*). The petroleum sector reduction potentials outlined above are material on this scale.

Extraction and processing of heavy oils and oil sands with current technologies is very energy- and carbon-intensive, and the ability to reduce the intensities is challenging. Although market forces have recently led to investment shifts based on economics alone (*12*), other mechanisms exist to reduce emissions. Solar-powered steam generators developed for heavy oil fields in Oman and California can provide substantial mitigation benefit. More broadly, use of solar energy could result in sectorwide emissions reductions on the order of 5 kg CO_2eq./bbl (~1.7 g CO_2eq./MJ) (*13*). For some key regions with high seasonality and poor economics of solar technology (like Canada), using energy inputs with low carbon intensity (e.g., hydrogen sourced from wind and biomass), capturing CO_2 from oil sands extraction and upgrading facilities, and investing in new low-carbon technologies (e.g., nanoparticle-assisted in-situ recovery, or CO_2-free production of H_2 from CH_4 via catalytic molten metals) would be beneficial. In addition, low-value but high-carbon products such as petroleum coke from upgraded oil sands could be sequestrated in lieu of combustion (*10*). Countries with diverse resources could reduce their national CI by prioritizing less carbon-intensive assets (e.g., tight oil), accompanied by stringent flaring and venting management.

Flaring rates can also be reduced. The Global Gas Flaring Reduction Partnership (GGFR) reported a nearly continuous increase in global flared gas from 2010 to 2016. Flaring is a management and infrastructure problem and is not an unavoidable outcome of crude oil production. Plans for new oil field development should incorporate conservation methods (i.e., capture, utilization, and/or reinjection) to eliminate routine flaring. Canadian regulations point to a method for enforcement: For offshore fields where flaring is excessive, production rate restrictions are imposed until flaring reductions are made (*14*). Initiatives like the World Bank GGFR Zero Routine Flaring by 2030 are a start, though these could be strengthened with international advisory, financial, and technical aid to help countries implement flaring reduction policies. Moreover, continuous monitoring and verification are essential not only for flare management but also for eliminating venting and fugitive methane emissions in the oil and gas sector. Modern surveillance using remote-sensing technologies (e.g., flare- and methane-sensing satellites) could be supported and expanded (*10*).

Methane fugitive emissions and venting from oil and gas facilities are poorly detected, measured, and monitored, and thus, can increase the uncertainty associated with CI estimates. Recently, the International Energy Agency (IEA) estimated 76 Mt methane emissions from global oil and gas operations in 2015, with ~34 Mt due to oil production (*15*). This prorates to ~4.6 g CO_2eq./MJ crude oil, higher than this study's estimate of methane contribution (~2.6 g CO_2eq./MJ averaged from all global fields, from all fugitive emissions and venting). In many cases, reducing methane emissions can result in additional revenues from the captured methane. IEA estimates that around 40 to 50% of current methane emissions could be avoided at no net cost. The cost of mitigation is generally lowest in developing countries in Asia, Africa, and the Middle East, but in all regions, reducing methane emissions remains a cost-efficient way of reducing GHG emissions (*15*).

Important questions remain with regard to the interactions of economics and emissions. The CI curve in the second figure reflects differences in CI, but crude oil production choices are obviously influenced by the interaction of local production costs and the global price of oil. A market structure without carbon prices neglects differences in CI shown in the second figure. Future work needs to examine the interaction of supply economics and CI for different resource classes.

Data-driven CI estimates such as this work can encourage prioritizing low-CI crude oil sourcing, point to methods to manage crude oil CI, and enable governments and investors to avoid "locking in" development of high-CI oil resources. However, future progress in this direction will rely fundamentally on improved reporting and increased transparency about oil-sector emissions.

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SUPPLEMENTARY MATERIALS

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