Fossil Fuel Operations sector: Oil and Gas Production and Transport Emissions

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1. Introduction

The petroleum resources that are extracted and transformed into usable products for today's economy are not equal. In reality, their characteristics, production methods, operational stewardship—and thus, their climate impacts—vary widely (Gordon et al., 2022). By treating oil and gas as homogeneous, we miss opportunities to reduce greenhouse gas (GHG) emissions from the sector. Taken together, emissions from production, refining, and transportation of oil and gas represent more than 15 percent of global anthropogenic emissions. Therefore, these are critical sectors to mitigate to limit global temperature rise below 1.5 degrees C.

Numerous approaches—bottom-up, top-down, and hybrid methods—exist today to evaluate emissions from petroleum systems. Top-down methods typically record emissions via tower-based measuring stations, drive-by detection, and fly-over techniques, including satellites, aircraft, and drones. Meanwhile, bottom-up methods assess emissions from the ground-up, often estimating emissions based on equipment counts and component-specific emission factors for leaks during the production process. No single method of emissions accounting is entirely decisive. A hybrid ecosystem including systems modeling, remote sensing, and direct measurements is necessary to provide information that better facilitates widespread reductions across the sector.

Recent studies suggest that methane from oil and gas systems has traditionally been undercounted in corporate- and country-level reporting systems (Alvarez et al., 2018; Yu et al., 2022). In part, this is due to difficulty quantifying methane resulting from the burning off of unwanted natural gas during oil extraction, a process known as flaring (Plant et al., 2022). More substantially, methane is undercounted because bottom-up methodologies are unable to capture stochastic, large emission events–referred to as "super emitters"– where massive quantities of methane leak into the atmosphere (Rutherford et al., 2021). Super-emitters can comprise less than 5 percent of discrete, individual sources, yet represent more than 50 percent of total emissions (Brandt et al., 2016). In the last few years, the deployment of top-down, remote sensing technologies has captured the effects of super-emitter events at the regional level.

Findings suggest these events account for as much as 20 to 60 percent of regional methane emissions (Cusworth et al., 2022). The message is clear: improving detection, measurement, and quantification of super-emitting methane sources is critical for improving emissions estimation and mitigation.

The Climate TRACE production and transport sector emissions estimates rely on methodology established by the Oil Climate Index + Gas (OCI+) tool. The OCI+ tool is built on three underlying models that estimate emissions from the oil and gas supply chain: (1) the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) assesses the upstream (production and some transport) portions of the petroleum lifecycle, (2) the Petroleum Refinery Life Cycle Emissions Model (PRELIM) assess emissions from midstream oil refining, and (3) the Oil Products Emissions Model (OPEM) quantifies downstream end use transport and consumption emissions from oil and gas products. More information on the OCI+ tool can be found here: https://ociplus.rmi.org/. The OPGEE model is explained further below, the PRELIM model is explained in the TRACE refining sector methodology, and OPEM is not used for emissions estimates from TRACE oil and gas sectors, since end use is encompassed by other TRACE sectors. OPGEE was developed by a team from the California Air Resources Board and Stanford University (Brandt et al., 2021). OPGEE has been peer-reviewed and used internationally by policymakers (Masnadi et al., 2018). Through the use of novel analyses of remote sensing data to generate inputs for OPGEE, Climate TRACE provides critical insight into global sources of GHG emissions from the oil and gas sector.

2. Overview: Materials and Methods

The OCI+ is an open-source, hybrid systems tool that quantifies emissions from oil and gas production, processing, refining, shipping, and end uses. OCI+'s upstream component, OPGEE, covers emissions from all operations that are involved in producing and transporting crude hydrocarbons to the refinery gate, as well as gas molecules to the point of end use consumption. OPGEE is the foundational model to estimate emissions for this TRACE sector. Figure 1 provides a flowchart of the OCI+ models and how their inputs and outputs feed into each other.

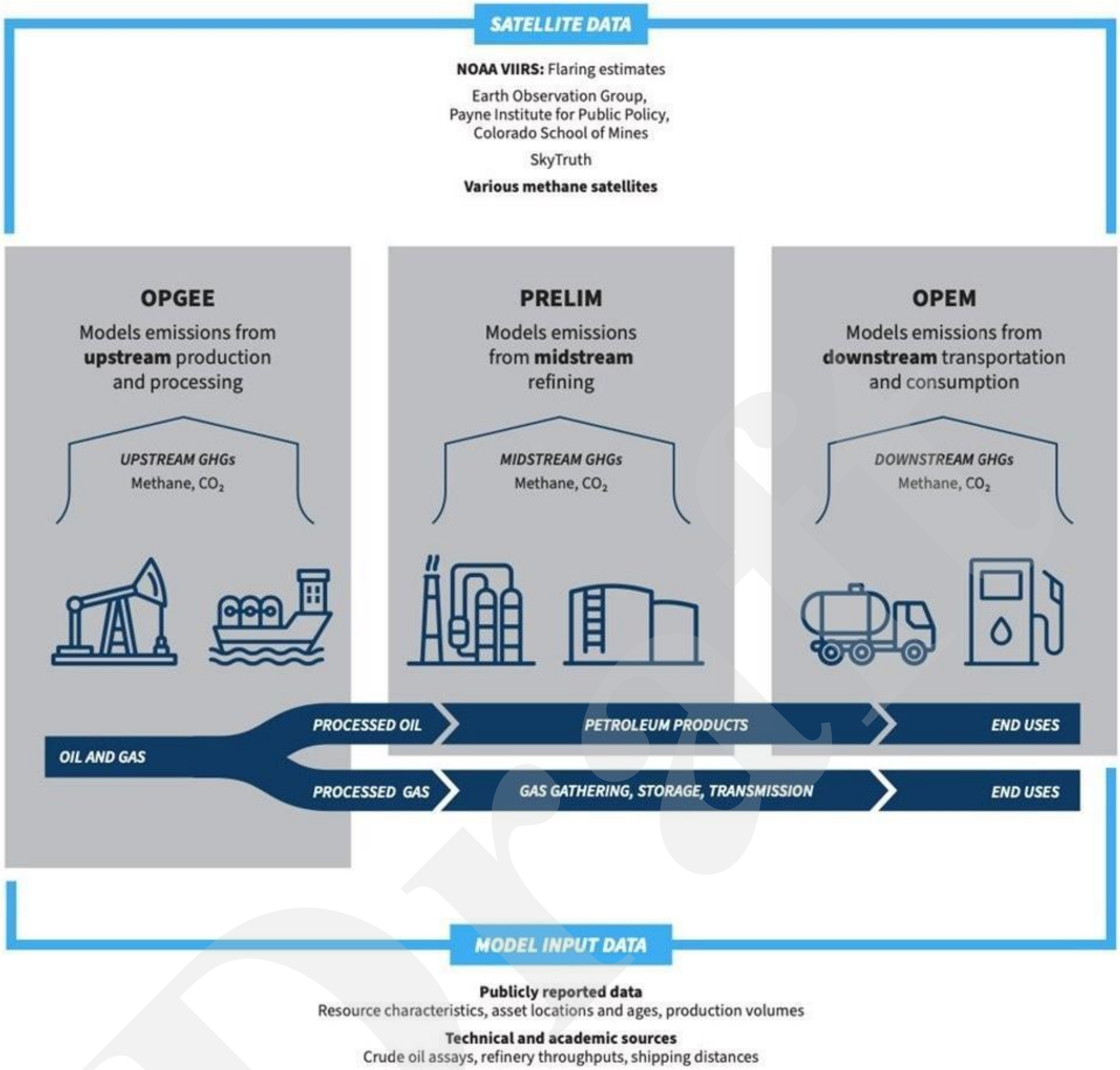

Figure 1. The OCI+ quantifies GHGs from the upstream, midstream, and downstream components of the petroleum lifecycle. The upstream and midstream portions, OPGEE and PRELIM, were used in Climate TRACE's models for oil and gas production and transport, and refining (TRACE refining is in a separate methodology document). Here, "upstream" refers to drilling, extraction, pre-processing, and transport of crude oil and natural gas. "Midstream" refers to oil refining. The "downstream" components of the life cycle – transportation of refined products and consumption by end users – are not discussed here.

Climate TRACE production estimates used OPGEE to model global oil and gas fields and subfields, hereafter identified as "assets". These "asset-level" results were aggregated to country-level emissions. Climate TRACE relied on both bottom-up reported data and activity data, as well as novel analyses of remote sensing data, to provide inputs for models.

The OPGEE approach to estimate oil and gas production and transport emissions is provided in section 3. OPGEE modeling results are described in section 4.

3. Materials and Methods: OPGEE - Oil and Gas Production and Transport Emissions

3.1 Asset Definition

The emissions data from the production and transport is reported at two levels of granularity: (1) field level and (2) sub-field level. The two levels are described below.

Oil and gas fields. Oil and gas production assets were defined and selected by their unique names and, in most cases, matched to field boundary polygons provided by the Rystad Energy UCube dataset (https://www.rystadenergy.com/). These polygons existed for most fields outside the United States, as well as for California. United States fields not in California were defined in terms of macro-geological formations, such as the Permian Basin or Marcellus shale. In a few cases, these geological formations were split up into individual assets based on the geographical boundaries of the states or provinces in which they were located (e.g., Permian Texas and Permian New Mexico). Assets that contained a complex combination of products were defined more granularly to account for specific components of the geological formation (ex. Eagleford Shale - volatile oil, Eagleford Shale - dry gas etc). OPGEE is a lifecycle engineering model, meaning it includes emissions for each asset based on all extraction sites, wells, storage facilities, gathering stations, boosting stations, crude oil pipelines, gas compression stations, and gas transmission lines associated with the asset.

For the oil and gas production field-level assessment, emissions were generated for about 700 oil and gas fields globally, representing about three-quarters of global production. The assets are located in 90 countries, and the countries represented produce over 98 percent of the world's oil and gas. Modeled oil and gas resources were selected based on their volumetric size, and geographic, geologic, chemical, and physical diversity. Fields producing less than 5 barrels equivalent per day of oil and gas were removed from the dataset. The final arbiter of the global resources selected was data availability. Numerous additional oil and gas resources can be modeled if greater data transparency were voluntarily provided or mandated.

Fields were geolocated by their coordinates as given in the Rystad Cube. Commonly, when multiple assets were in the same field (e.g., two different production sites with different operations in the same field), these were aggregated under a single field name and the average of the coordinates was taken. Any missing coordinates were sourced from desk research of public sources.

Oil and gas sub-fields. In the United States, sub-field level emissions are provided. These emissions estimates are much more granular than the field-level emissions described above. For example, in large oil and gas fields within the United States, operation and ownership of the field is complex and varied. The sub-field level estimates report emissions at the operator level (with the exception of Permian, which is reported aggregated as Permian New Mexico and Permian Texas).

3.2 OPGEE Model

3.2.1 Emissions Sources

The OPGEE model is divided into modules and broken up by major production stages. Over 100 emission sources were classified across all process stages. For a full and detailed accounting of all the OPGEE modules, stages, and processes, see Brandt et al. (2021). For the current discussion, this section provides a broad overview of the emissions sources covered by OPGEE, the gases included in the current analysis, and the parameters required as model inputs to estimate emissions. Emissions sources included:

- **Flaring.** Combustion of natural gas as a means of depressurizing an extraction or processing site. Flaring predominantly generates CO_2 and CH_4 emissions.
- **Venting.** Leaking of natural gas as a means of depressurizing an extraction, processing, or transmission site. Venting predominantly generates CH_4 emissions.
- **Fugitive losses.** Natural gas leaks originating from the equipment used in the production, processing, compression, and transmission of crude hydrocarbons.
- **Super-emitter events.** Large natural gas leaks (emissions rate generally 25 kilograms of methane per hour or greater), intentional or otherwise, occur in the production, processing, compression, and transmission of crude hydrocarbons.
- **On-site fuel usage.** Combustion of fuels on-site to power vehicles, drilling rigs, and other equipment.
- **Biogenic emissions.** Emissions caused by changes to the ecosystem at the extraction site, either as a result of deliberate site preparations (combustion and/or clearing of biomass) or indirect impacts on the local environment.
- **Embodied emissions.** Emissions associated with the manufacture of the materials used at the extraction site (cement, casings, etc.). Emissions associated with the consumption of electricity at the site.

3.2.2 Gases

It should be noted that, in addition to CO_2 and CH_4, OPGEE also assesses volatile organic compounds, carbon monoxide, and nitrous oxide. However, absolute volumes of these trace gases could not be easily teased apart for this analysis. Therefore, these emissions were included in the overall CO_2 equivalency results reported at the asset and country level and were not estimated on the level of individual gases.

3.2.3 Key Inputs

To estimate total emissions from all the sources and gases listed above, OPGEE requires some key inputs to establish the parameters of the model. Prior research has demonstrated emissions results to be sensitive to these inputs. Key inputs included:

- **Field age**. The number of years since the first year of production for the field. Age can be an indicator of depletion and predict greater energy expenditure per unit of production.
- **Field depth.** The depth of drilling operations. Deeper fields may be more energy intensive.
- **Oil, gas, and water production volumes**. Larger hydrocarbon production volumes indicate more emissions-generating activities. A high water-to-oil or gas-to-oil ratio can predict higher energy expenditure for the processes of separating fluids and extracting products.
- **Gas composition.** The ratio of different gas species in the reservoir. For instance, dry gas fields tend to have high (>90%) CH_4 content compared to wet gas fields, which have higher C2-C5 components.
- **Injection characteristics.** Gas, steam, and/or water may be injected into extraction sites to increase the flow of oil to wells, or manage the pressure at a site. The substance, volume, and methods of injection can all impact the emissions generated during production.
- **Well characteristics.** The number, type, depth, diameter, and production volume of wells impact the energy expenditure for a unit of production from a field.
- **Reservoir characteristics.** The pressure and temperature at the depth of the drilling operation.
- **Crude API gravity.** The inverse of the density of a petroleum liquid relative to water. Oils with higher API gravities are lighter and lower API gravities are heavier.
- **Production methods.** The extraction methods and emissions management techniques implemented at sites within a field. For instance, fracking is often associated with higher emissions.
- **Means and distance of transport.** The pipelines, transmission lines, vehicles, and management practices associated with transporting product from a field. For instance, gas may be distributed regionally from the point of production via pipeline, or liquefied and transported transoceanically via tanker. See note in **Liquefied natural gas (LNG), oil and gas transport distances** section about the need for careful analysis when it comes to attributing transport emissions.

- **Flaring volumes and efficiency.** Higher flaring volumes generate more emissions. Flare efficiency determines the ratio of combusted and uncombusted gas products that are generated.
- **Super-emitter events.** Large and/or frequent super-emitter events generate more emissions.

While the list above serves as a general summary, OPGEE can ingest more than 50 data inputs to estimate emissions. However, for most fields, a complete dataset containing every key input was not available. In these cases, OPGEE used the available inputs to generate reasonable estimates for the missing parameters. For instance, if the water-to-oil ratio for a field is unknown, OPGEE can estimate this parameter based on API gravity and field age. The default estimates OPGEE uses for missing parameters were based on a body of historical datasets tracking thousands of global oil and gas fields. See Brandt et al. (2021) for detailed information.

3.3 Datasets for ground truth and activity data

Many publicly reported, technical, and academic sources served as ground truth and activity data for OPGEE. These include industry-specific journals, scientific studies, government agency websites, and reputable news sources. Additional upstream activity data come from Rystad Energy's UCube (however, only derivative products are published). Other than Rystad UCube and Oil and Gas Journal data, which require subscriptions, all sources are openly available. Table 1 summarizes key input data sources for OPGEE.

Table 1. Data used as inputs to OPGEE

OPGEE Model Inputs for Oil and Gas Production and Transport		
Input	**Source**	**Critical Regions & Field Types**
Field age	Derived from Rystad Energy UCube	All global fields
Field depth	Technical industry references & publicly reported sources (e.g., Science Direct)	Brazil, China, Offshore assets
Gas-to-oil ratio	Derived from Rystad Energy UCube and satellite-derived flare volumes	All global fields
Production volumes	Derived from Rystad Energy UCube	All global fields
Gas composition	Technical industry references & publicly reported sources	Coal bed methane assets, sour and acid gas assets (high sulfur, methane, or CO2 content)
API gravity	Derived from Rystad Energy UCube & publicly reported sources (e.g., One Petro)	Global oil fields
Injection characteristics	Technical industry references (e.g., Oil and Gas Journal) & publicly reported sources	Canadian oil sands, extra heavy oils, high water content fields
Production methods	Derived from Rystad Energy UCube & publicly reported sources (e.g., Offshore Technology)	Fracked fields, enhanced oil recovery fields
Transport means and distances	Public databases (IEA Sankey, BP Statistical Review of World Energy, Global Energy Monitor Gas Infrastructure Tracker)	All global fields

3.4 OPGEE Settings

Within OPGEE, there are a variety of settings that users can select to customize implementation of the model. This section describes several key settings that were selected for this analysis.

3.4.1 General Settings

Product-specific boundaries. OPGEE users can set boundaries for which stages of the upstream hydrocarbon production process should be included in the model's emissions estimates for a given asset. For oil-dominant fields, meaning the primary economic product from the field is crude oil, Climate TRACE opted to include emissions from all processes leading up to the crude oil product's arrival at a refinery. Meanwhile, gas-related emissions were included only at the level of activities within the field itself (i.e., no gas transport emissions were included). This was a practical decision and model best practice given that oil-dominant producers often do not have physical connectivity or economic incentive to supply small gas volumes to gas networks. For gas-dominant fields, where the primary output is gas, the emissions results included processes all the way to the point of gas distribution, whereas oil-related emissions were restricted to activities within the field itself. If a field produced large amounts of both oil and gas, the oil and gas components were run as separate sub-fields, and their emissions aggregated into the total for the asset.

Production methods. If an asset had some component products that were produced via both conventional and fracking methods, these were split into two sub-fields with different settings (frack on, frack off), and their emissions were aggregated into the total for the asset.

Methane venting, fugitives and flaring. The methane venting and fugitives (VF) portion of the model requires "component" or "site" level analysis to be selected. Site-level methods for estimating VF emissions leveraged empirical data from site-level emissions measurement campaigns, typically performed at or beyond the facility fence-line. Component-level methods for estimating fugitive emissions start with a list of components present at a site and estimate leakage by component. The model authors recommended the component-level method to be used in Climate TRACE analysis. All fields and sub-fields are modeled at the component level except for in Norway, where fields are run at site level to accommodate the representation of on-shore renewables used to power offshore extraction platforms.

Flare slip, also called "methane slip", is another source of methane due to flaring. Flare slip occurs when a flare malfunctions and excess methane is not burned off and thus is not converted to CO_2 (remains as methane). For most assets, methane combustion efficiency for flares was set to 90%. A handful of countries and regions with enforced efficiency regulation were set to 98%, such as Canada, Norway, and the Permian New Mexico field.

Model outputs and barrel of oil equivalency (BOE). Oil and gas field inputs were specified based on the datasets in section 3.3. The model was run to calculate GHG emissions outputs for each oil and gas asset. Under California regulations, OPGEE reports GHG-emissions outputs in units of grams CO_2 equivalent per megajoule (gCO_2e/MJ) of petroleum products generated. CO_2 equivalent was calculated using both 100-year and 20-year global warming potential for all gases. These outputs were converted into emissions per barrel of oil equivalent ($kgCO_2e/boe$) by multiplying them by the weighted lower heating value of all processed oil and gas products (lower heating value is an energy density metric measured in megajoules per barrel of oil equivalent), which is output in OPGEE's Energy Summary tab.

3.4.2 Settings for Special Cases

OPGEE offers numerous settings to best reflect real-world production and transport operations specific to individual fields.

Liquefied natural gas (LNG), oil and gas transport distances. Gas fields where a significant portion of the gas product feeds into an LNG plant, as determined with the Rystad Ucube dataset, were run with the LNG setting "on". All other fields transmit and distribute gas via pipelines only and do not generate liquefaction, LNG transport, or regasification emissions.

Distances for LNG transport (tanker), crude oil transport (tanker), and gas transmission (pipeline) were established at the country-level and used for all assets in those countries. The sole exception is Cook Inlet, Alaska, which was assigned its own distance to reflect local gas consumption instead of using U.S. country values. All distances were calculated by first determining whether produced oil and gas was primarily consumed in-country or exported to a main off-taking nation (IEA 2019; BP 2022). If products were primarily consumed in-country, we used publicly available oil and gas pipeline datasets to calculate the distance from production sites to the country's largest city, where large-scale refining and gas consumption was likely to occur (e.g., gas production in southern Argentina to Buenos Aires) (Global Energy Monitor 2022). If products were primarily exported, we used a combination of publicly available cross-border pipeline datasets and shipping routes to calculate the distance from the area of production to the main offtaker (e.g. offshore Norway oil and gas production to Paris).

Careful attribution is needed when considering transport emissions. This is especially true for gas transport emissions, which can be a significant portion of emissions from a gas supply chain. While oil and gas is transported around the world, it is very difficult to track the actual path and destination for any given set of produced molecules. The OPGEE model accounts for emissions that occur as a result of moving crude oil and natural gas via general modes, such as pipelines and ocean and LNG tankers. These are linked back to the field of origin, even though the actual emissions may have occurred outside of those bounds. For example, Algeria exports gas to Europe and it may travel hundreds of miles to get there, such as via the Trans-Mediterranean Pipeline, shown in Figure 2. The pipeline spans 2,475 km and links Algeria to Italy (source: GEM). Various pipeline sections are owned and operated by Sonatrach (Algeria), Sotugat (Tunisia), and ENI (Italy). When modeling a gas field in Algeria, pipeline transport emissions are estimated and linked back to the Algerian gas field even though they may actually be occurring over Tunisian or Italian-owned areas.

Our emissions for transport reflect the emissions that the atmosphere 'sees' given the oil and gas produced from that asset and/or in that country.

Figure 2. The Trans-Mediterranean Pipeline that links Algeria to Italy.

Coal bed methane. In some fields, natural gas was extracted from underground coal beds. These fields, which can be identified in the dataset by having "coal bed methane" in their name, were assigned specific gas composition percentages H_2S (2%), methane (93%), CO_2 (5%), field depth (800 ft), reservoir pressure (329 psi) and temperatures (84°F). Water reinjection practice was turned on, and water-to-oil-ratio (WOR) was calculated by dividing the gas-to-oil-ratio (GOR) by 2000.

Additional special cases. For Norwegian fields Gudrun, Johan Sverdrup, Gjoa, and Troll, natural gas-fired equipment, such as reinjection compressors, were substituted to instead be powered by renewable electricity. Snohvit, Shah, In Salah, Sleipner West, and Greater Gorgon fields, which have high CO_2 content, were run with carbon capture and sequestration parameters "on", instead of the default which assumes that purged CO_2 is vented into the atmosphere. Assets located in California were assigned land carbon richness and development intensity inputs to align with those from California Air Resources Board analysis (CARB 2021) .

3.5 Remote Sensing Integration

In addition to ground truthing and using activity data, Climate TRACE incorporated remote sensing data to estimate flaring at oil and gas fields, as well as methane leakage factors for OPGEE.

3.5.1 Asset, infrastructure and remote sensing data

To estimate flaring volumes, we used the Visible Infrared Imaging Radiometer Suite (VIIRS) derived Gas Flaring product. VIIRS detects global gas flaring at 750 m resolution every 24 hours. The National Oceanic and Atmospheric Administration's (NOAA) VIIRS instrument, flying on the Suomi National Polar Partnership (SNPP) satellite, is uniquely designed to detect a heat signature produced when unwanted facility gas is burned off. The product is derived from detection at shortwave- and infrared bands (M10 and M11 bands) of 1.6 and 2.2 µm. At night, these bands are indicators of combustion sources and are thus ideally suited for finding flares. Flares were distinguished from wildfires by temperature (flares are designated at T > 1,400K) and persistence (wildfires are typically not persistent beyond a few days, while flares are). Figure 2 highlights VIIRS flaring volume locations for 2019. Data was accessed through the data portal of the Earth Observation Group, Payne Institute for Public Policy, Colorado School of Mines (https://eogdata.mines.edu/products/vnf/).

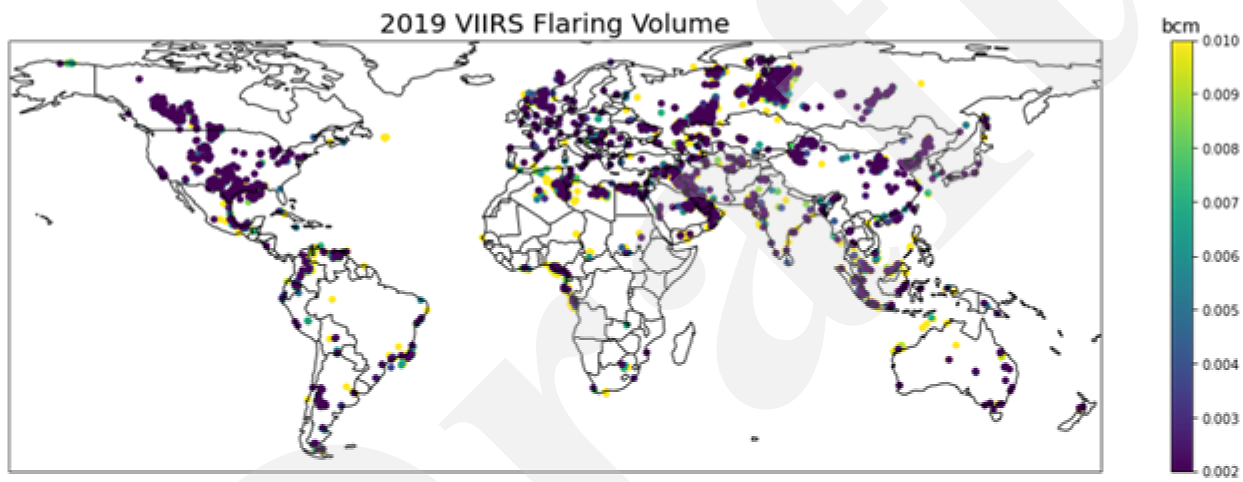

Figure 3. 2019 VIIRS flaring volumes in billions of cubic meters (bcm).

To assign flares to fields, we use two methodologies and different associated data, depending on whether or not the asset is within the U.S. or not.

- Within the U.S., flares are assigned by matching VIIRS geolocated flares to the nearest piece of oil and gas infrastructure, and matching the piece of infrastructure to a field. Infrastructure and operator information was compiled by individual state oil and gas agencies (e.g., Colorado Oil and Gas Conservation Commission)- these state-level records were compiled by FracTracker in their 'National Well Report' and the Global Oil and Gas Infrastructures (GOGI) database. Field locations were provided by Rystad and provide centroid latitude and longitude values for fields within the U.S..
- Outside the U.S., flares are assigned by matching VIIRS geolocated flares that fall within a field boundary. The field boundary polygons are provided by Rystad, and a buffer is added around the field to account for uncertainties in both polygon locations

and VIIRS flare locations, to capture flares that are attributed to the oil and gas production of that asset.

3.5.2 Flaring Integration

While flaring can occur all along the oil and gas supply chain, the VIIRS gas flaring product has observed that 90% of the flaring occurs in upstream production areas, while only 8% occurs at refineries, and 2% at LNG transport facilities (Elvidge et al., 2015). This flaring process produces both CO_2 and CH_4 (uncombusted gas 'slip'), and thus is essential in getting accurate GHG emissions estimates from the oil and gas sector. In collaboration with researchers at the Colorado School of Mines who process the VIIRS flaring observations, RMI quantified these emissions and produced a derived modeling metric, the flaring-oil-ratio (FOR, units of standard-cubic-feet per barrel-of-oil-equivalent or scf/bbl), which relates flaring to oil production at a field. FOR was computed by dividing the VIIRS variable flr_volume (volume of flared gas in billions of cubic meters, converted to standard cubic feet) by a field's oil production. A high FOR indicates a large amount of flaring per barrel of oil produced at a given field, and vice versa for a low FOR. It is worth noting that associated gas venting, which can come from malfunctioning flares, was modeled as a separate emissions source in OPGEE.

As mentioned above, an important part of deriving the FOR variable was assigning the satellite-observed flares to the correct oil or gas asset. To do this, RMI performed geolocation matching using all available oil and gas field polygon shapefiles from the Rystad GIS UCube database (this includes almost all fields outside of the U.S.) as well as publicly available polygons for California fields. A buffer was added around the polygons to account for uncertainties in the flare or field boundary locations. Any flares that fell within the available polygon buffered boundaries were assigned to that oil or gas asset. If a flare fell within two overlapping polygons, the flare was assigned to a field based both on distance to centroid and oil production as equal weights. For fields without polygon files (most fields modeled in the U.S.), a flare that fell within a radius of 10 miles (~16 km) of the field was assigned to that asset (a self-defined threshold choice). The exception was in the significantly larger Permian TX field, for which the distance threshold used was 50 miles (~80 km). Figure 4 details the flaring geolocation matching approach.

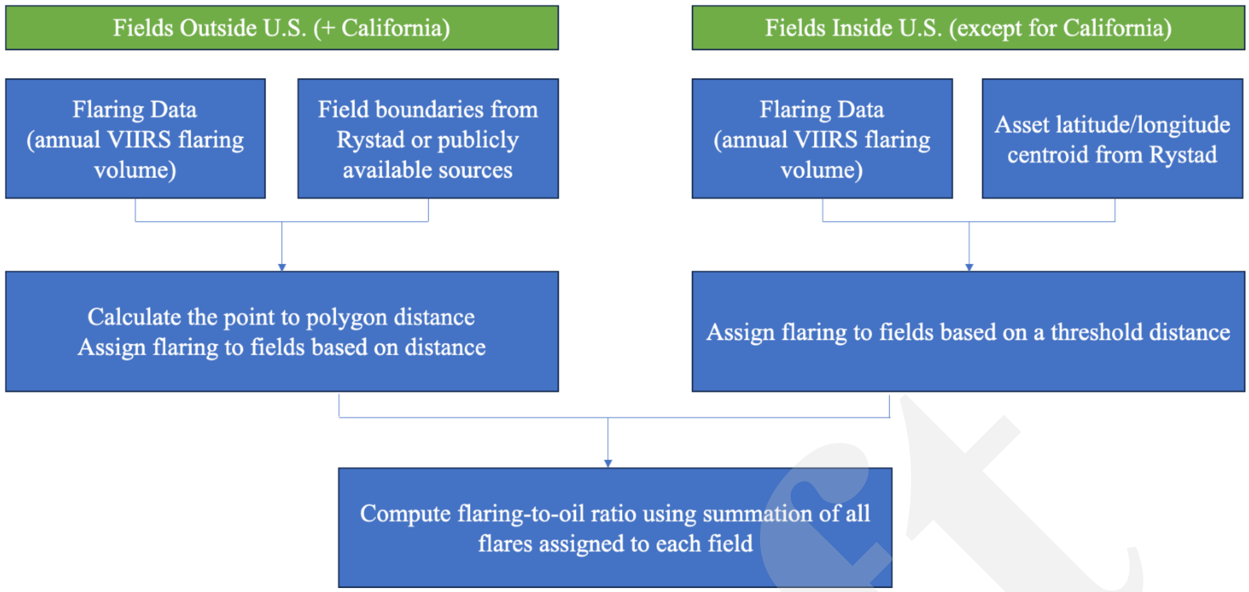

Figure 4. Approach to assign VIIRS flaring data to oil and gas assets based on the "World, except for U.S., and California" and "U.S. except for California".

3.5.3 Super-emitter methane detection with remote sensing

RMI's modeling approach incorporated results from several recent scientific studies on methane super-emitters. First, findings from Cusworth et al. (2021), which deployed aircraft surveys over the Permian Basin and attributed detected plumes to specific types of infrastructure, were used to inform RMI's model for fugitive loss rates for specific types of equipment, including storage tanks, wellheads, gathering and boosting stations, and processing equipment in Permian TX and Permian NM assets. In addition, Lauvaux et al. (2022) identified that extra-large super-emitters, or ultra-emitters, represent as much as 12 percent of global methane emissions. In their study, the TROPOspheric Monitoring Instrument (TROPOMI) on board the Copernicus Sentinel-5 Precursor satellite detected over 1000 super-emitters over the Middle East, Russia, Algeria, and Turkmenistan. By aligning the location of some of these detections with modeled assets, RMI adjusted OPGEE's default estimates for the fugitive loss rates for upstream equipment components in Algeria's Hassi R'Mel and Tin Fouye fields (Figure 5). Similarly, gas transmission pipeline fugitive loss rates were adjusted for the Permian basins in the USA, as well as all assets in Russia and Turkmenistan. Locations that did not have aligned detections had their defaults left as is.

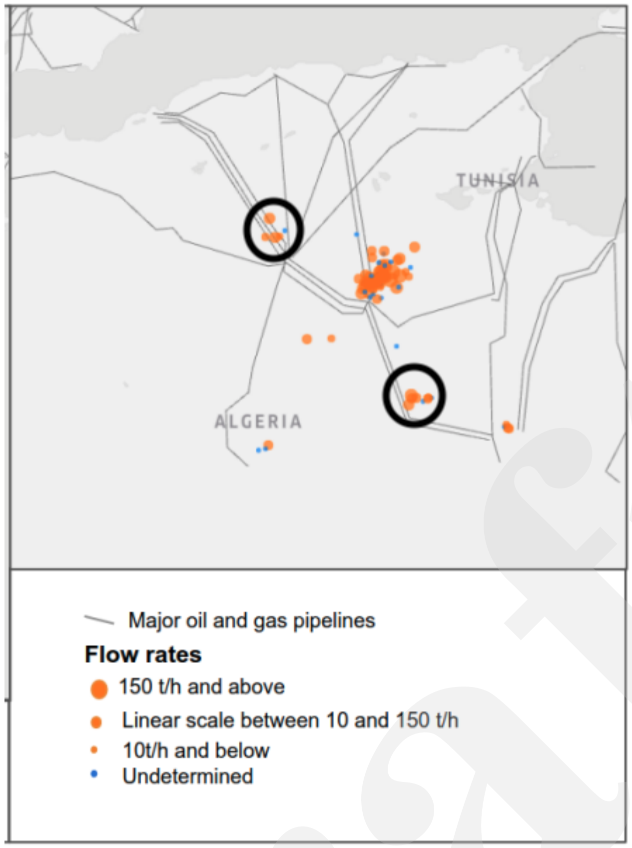

Figure 5. Methane emission detections (orange dots) over Algeria, from Lauvaux et al. (2022), overlaid with approximate locations of Hassi R'Mel and Tin Fouye fields (black circles).

Figure 6 shows the effect on methane emissions results from adjusting OPGEE's fugitive methane loss rates for three assets in Algeria, Turkmenistan, and the U.S.. In the case of Permian NM, our adjustments to upstream fugitive methane brought our overall result into close alignment from a recent study of the New Mexico Permian between October 2018 and January 2020 that found overall site loss to be about 194 tonnes per hour (+72/-68, 95% CI) (Chen et al., 2022).

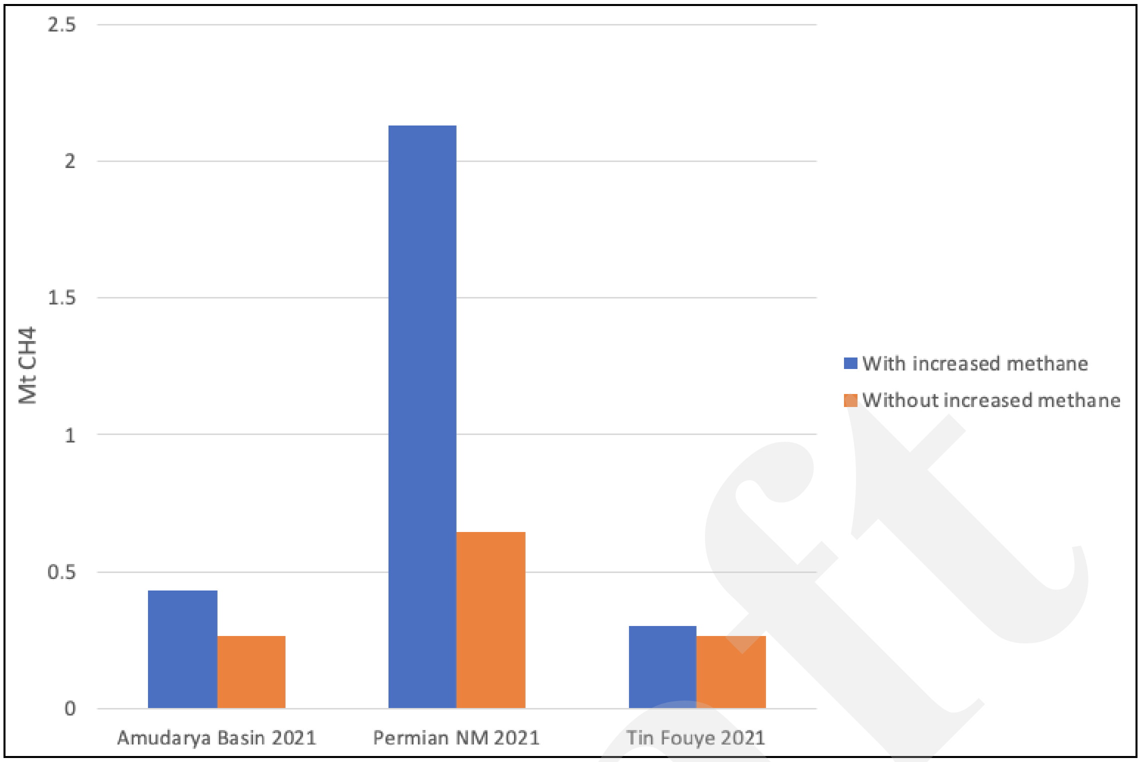

Figure 6. 2021 methane estimates from three assets - Amudarya Basin, Permian NM, and Tin Fouye - before (orange) and after (blue) adjusting OPGEE's inputs for fugitive methane loss.

3.6 Country-level estimation

Country-level estimates for methane, CO_2 and CO_2 equivalencies were generated by averaging the emissions intensities (in kg/boe) from field-level results in each country, weighted by individual fields' annual total oil and gas production. This produced a weighted-average country-level emissions intensity in kg/boe, which was then used to calculate the country level total emissions by multiplying total country annual oil and gas production measured in boe. This process ensures that a country's total emissions can be estimated when only a subset of all oil and gas assets in a country were modeled. For example, if 10 oil and gas fields in Country X were modeled following the asset-level approach, a country-level emissions intensity is assigned by a production-weighted averaging of the intensities of the 10 fields. Country X total emissions were calculated by multiplying the country-level emissions intensity by Country X's total production in a given year. In a few cases, assets with outlier emissions intensities (those that were unlikely to be representative of the country's assets as a whole) were removed from the production weighted averaging process so as to not inflate country level estimation (e.g., Brent, United Kingdom). If all of a country's assets were modeled, country level emissions were estimated by simply adding up emissions from all assets.

3.7. Confidence and Uncertainty

Confidence levels for the oil and gas production and transport sector were determined based on three things: (1) the number of known inputs provided to the OPGEE model to estimate emissions, (2) limitations of the model, and (3) comparability with other emissions inventories. First, if there is higher confidence in a sources'’s emissions estimates had more details known about an asset’s operations and, thus provided to the model as inputs, then the confidence was considered “high”. If there were not many known inputs and the model was allowed to default on many variables, the confidence for that field is considered “low”. Conversely, if most or all of the model inputs were sourced from data providers, the confidence for that field is high.

Second, the original version of the OPGEE model was built to assess emissions from oil fields, and more recently has been expanded to include modeling of gas fields. The confidence in modeling oil fields is higher than modeling gas fields, so the confidence has universally been set to low for all gas fields given the model limitations around these field types.

Third, if TRACE country-level CO_2 and CH_4 estimates of oil and gas emissions were largely different from the IEA inventory *and* not easily explained by differing methodological approaches, Climate TRACE set the assets in that country to be marked with low confidence.

Note that uncertainty numbers were not provided for the oil and gas production and transport sector this year. However, the team has developed a detailed methodology that will allow uncertainty estimates to be presented in future data deliveries. To estimate uncertainty, the OPGEE model will be run in multi-realization mode. Allowing the model to run 100+ times for a given asset allows the model to sample many times from the distributions that are used in Monte Carlo simulations within the model. By running the model 100+ times allows the model to stabilize and statistical estimates of uncertainty can be obtained. Given the heavy computational requirements of this modeling, paired with the many thousands of assets in this sector,

4. Results: Oil and Gas Production and Transport

One of the most important findings from the oil and gas production and transport sector is that there is a very large range of emissions intensities (emissions per barrel of oil equivalent). Emissions can vary by 10x to extract the same oil or gas, depending on reservoir characteristics, operational practices, equipment maintenance, and more. Figure 7 shows a box and whisker plot of carbon dioxide emissions intensity from oil and gas assets in the United States alone, with an interquartile range of 8x. Prioritizing use of oil and gas resources with the lowest emissions intensity during the energy transition would mean less emissions to the atmosphere in the long run.

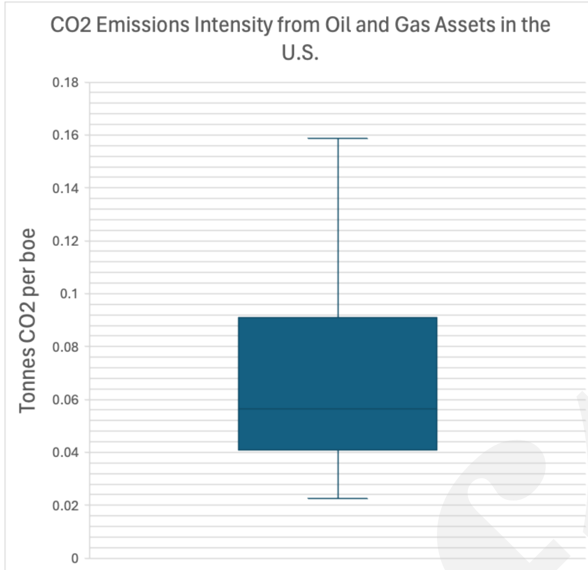

Figure 7 Box and whisker plot showing 5th, 25th, 50th, 75th, and 95th percentile CO_2 emissions intensities from modeled oil and gas assets in the United States.

Figure 8 shows the top 10 countries with highest emissions from the oil and gas production and transport sector. Russia is the largest emitter for all years, emitting between ~2 to ~2.5 billion tonnes for years 2015 to 2022. The U.S. is the second largest, emitting between ~1.4 to ~1.75 billion tonnes for years 2015 to 2022. The third highest emitting country, Iran, emitted between ~0.4 to ~0.6 billion tonnes between 2015 to 2022, nearly half of the Russian and U.S. emissions followed by U.S, and both these countries have more than double the emissions and the USA have particularly high emissions, more than double that of the third highest emitting country, Iran, for all years modeled.

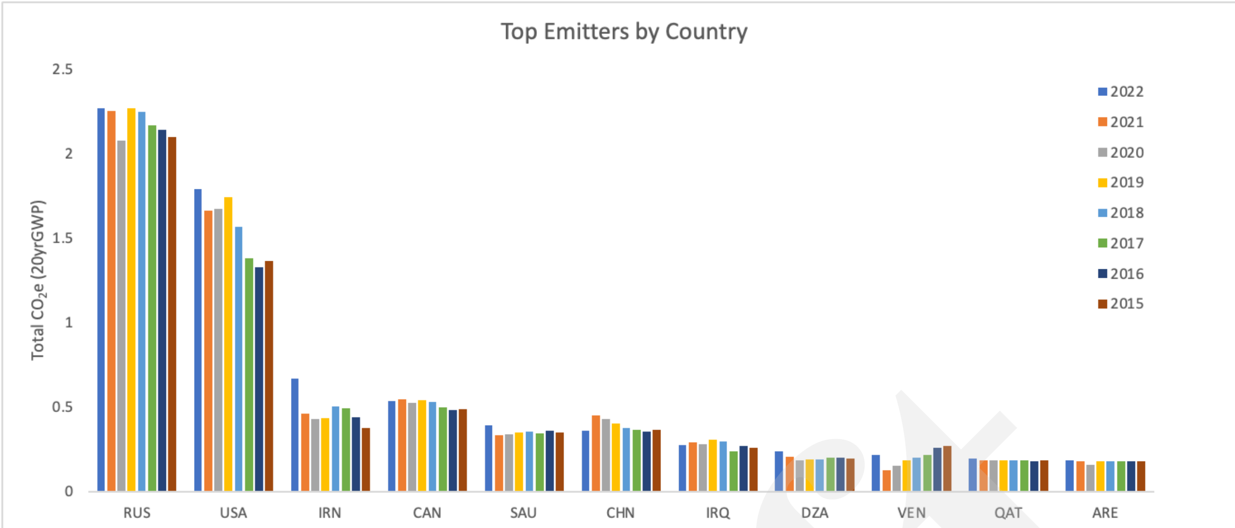

Figure 8 Top 10 global oil and gas production and transport emitters, for years 2015-2022. The y-axis unit of measure is billion tonnes of CO_2e 20 year global warming potential (GWP).

Figure 9 shows the top flaring countries by volume for modeled assets. Countries that flare high volumes of gas, such as Russia, Iraq, Iran, and the U.S. , are also amongst the top overall emitters in Figure 8. Notably, Canada is the fourth largest overall emitter in Figure 8, due to its high volumes of production, but does not have high flaring volumes and does not rank in the top 10. Flaring inefficiencies also contribute to overall methane emissions--in our analysis, flaring efficiency is estimated at 90%, meaning 10% of flared gas escapes as uncombusted methane. Flaring accounts for approximately 12.5% of total methane emissions from oil and gas production and transport, as shown in Figure 10. Increasing flaring efficiency or capturing and selling the gas that would otherwise be flared is a low hanging fruit in reducing emissions in this sector. Oftentimes addressing flaring as an emissions reduction strategy is low cost or even profiting for operators.

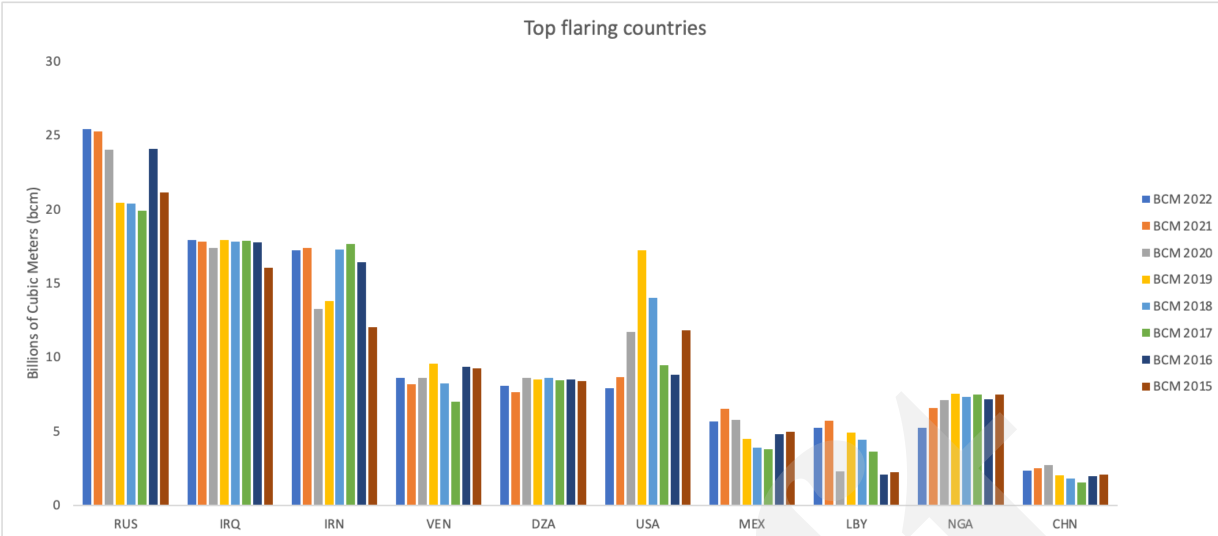

Figure 9 Top 10 countries by flaring volume (bcm) for years 2015 to 2022. The y-axis unit of measure is billions of cubic meters.

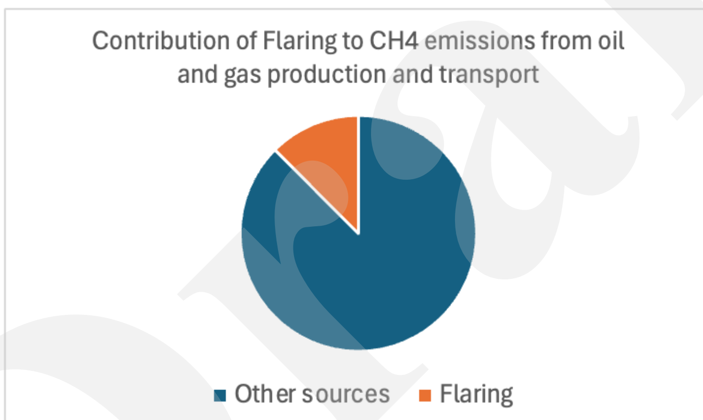

Figure 10 Contribution of flaring to total methane emissions from oil and gas production and transport.

4.1 Comparison with Other Emissions Inventories

Our asset-level emissions intensities are compared against comparable estimates for global oil and gas fields published in Masnadi et al. (2018) and the Oil Climate Index + Gas (RMI 2022).

Additional comparable sources for absolute CO_2 equivalent and methane emissions include: Global Registry on Fossil Fuels (GRFF), Global Fuel Emissions Inventory (GFEI), Emissions Database for Global Atmospheric Research (EDGAR), United Nations Framework Convention on Climate Change (UNFCCC) National Submissions, and International Energy Agency (IEA) Methane Tracker. We do not always include a numeric comparison to all existing inventories because several are based on similar underlying datasets and therefore do not offer new country-level estimates.

Like Climate TRACE, The IEA Methane Tracker estimates all CH_4 emissions that occur across segments of the oil and gas supply chain, including production, gathering and processing, refining, transmission, and distribution. The foundation for the estimates is the U.S. GHG Inventory, which is used for developing emissions intensities for venting, fugitive, incomplete flaring, broken down by production subsectors: on and offshore, and conventional and unconventional. With the U.S. intensities serving as a baseline, multipliers are developed for each country based on several factors, including regulatory effectiveness, age of operations and infrastructure, etc (International Energy Agency, 2021). IEA also incorporates satellite-derived ultra-emissions of methane from Kayrros analytics based on Sentinel-5P TROPOMI.

Figure 11 compares Climate TRACE results for top methane-emitting countries with IEA 2021 estimates and Figure 12 compares Climate TRACE emissions results for several UNFCCC annex-1 country inventory submissions. Overall, Climate TRACE results for country-level emissions align most closely with IEA Methane Tracker results compared to any other inventory. In 2021, IEA estimated global methane from oil and gas production and transport to be approximately 82 megatons (Mt). Climate TRACE estimated this total to be approximately 80 Mt. However, Climate TRACE Annex 1 results are more than double that of UNFCCC Annex 1 estimates in Figure 12. Moreover, TRACE estimates demonstrate an increase in 2016-2019, while UNFCCC estimates display a flat trajectory.

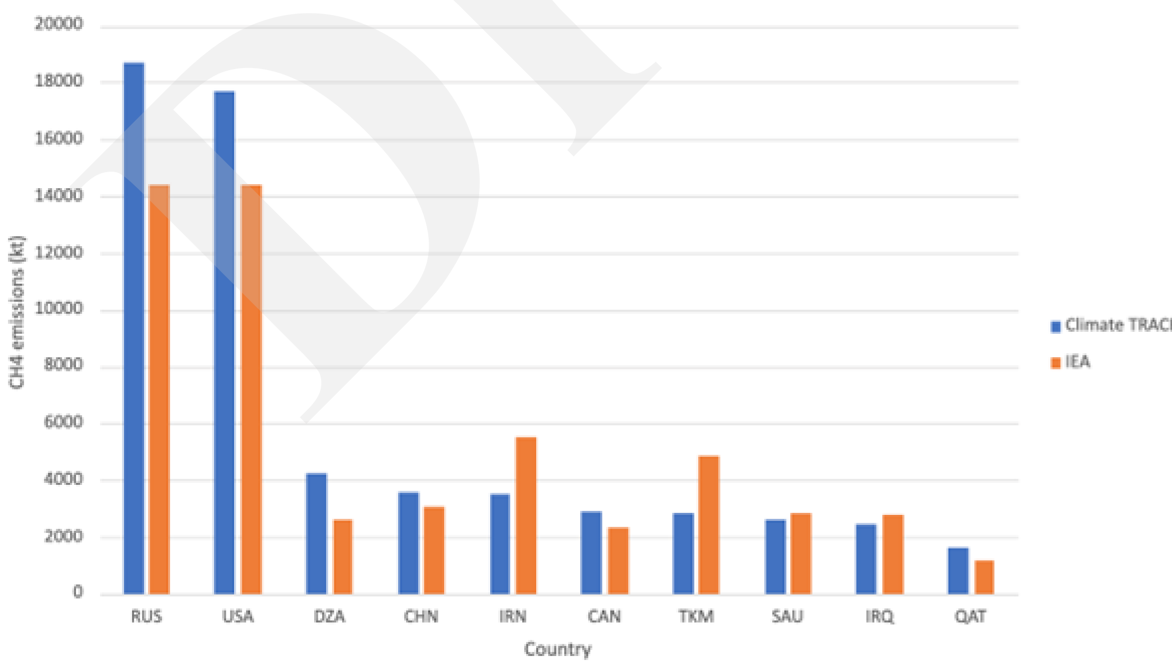

Figure 11 Top 10 global methane emitters, comparison with IEA Methane Tracker 2021.

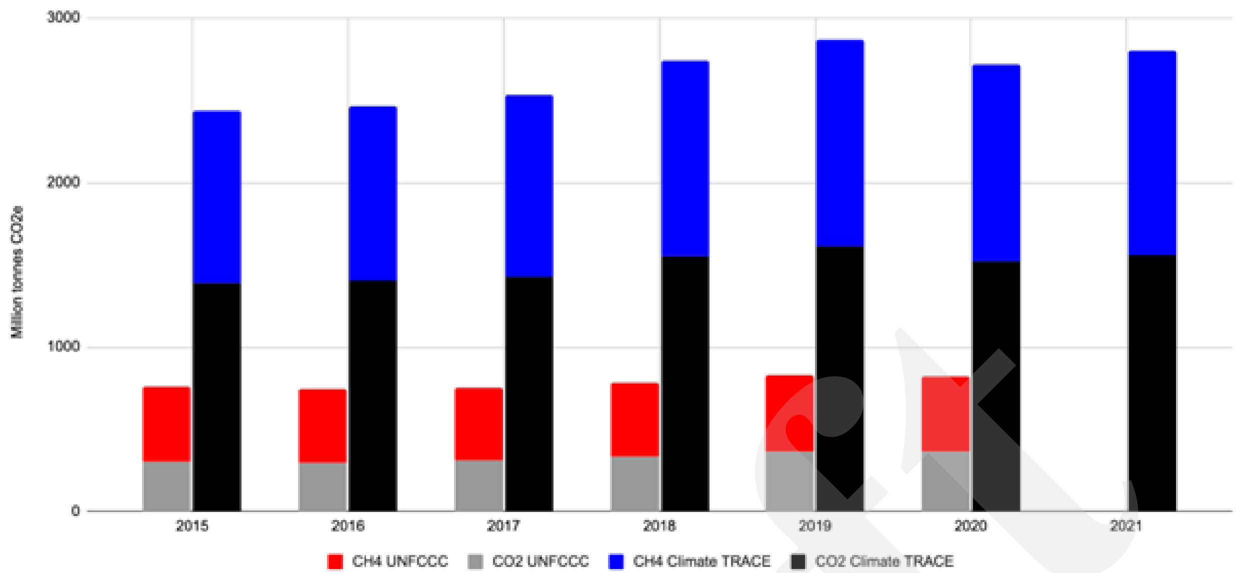

Figure 12 Comparison of CO_2 and CH_4 estimates for UNFCCC Annex 1 countries (100 year GWP). Comparison includes 19 countries for which comparable UNFCCC data was available, including Russia, U.S.A., Australia, Bulgaria, Canada, Germany, Denmark, Spain, France, U.K., Greece, Croatia, Italy, Japan, Kazakhstan, New Zealand, Norway, Netherlands, and Ukraine.

The significant difference between Climate TRACE and UNFCCC estimates can be partly attributed to UNFCCC emissions reporting style. The UNFCCC inventory is based on national inventory submissions from two groups of countries—Annex 1 and non-Annex 1 countries (United Nations 2021). Annex 1 comprises forty-three countries, mostly advanced economies. To measure production and refining emissions, Non-Annex 1 countries rely primarily on "Tier 1" methodology, which use default emission factors and relatively simple equations provided by the Intergovernmental Panel on Climate Change (IPCC). Annex 1 countries may develop country-specific emission factors for CO_2 and CH_4 based on fuel properties (*i.e.,* carbon content, heating value) and use activity data such as fuel consumption statistics. This is consistent with the IPCC "Tier 2" approach. Countries with higher levels of visibility into their refining and production processes may use more detailed data, such as from national inventory and reporting programs. Starting at the facility or even process-unit level, some countries create high resolution, technology-specific emissions factors, described as a "Tier 3" approach. Because Non-Annex 1 countries are not required to report regularly or in a standard format, total country comparisons between Climate TRACE and UNFCCC global datasets are difficult.

Unlike the UNFCCC, and EDGAR, which generally apportion total fuel use to each sector and multiply by emission factors, OPGEE uses engineering process-level detail for particular fuel pathways and publicly available information wherever possible. While EPA emission factors are used for some emissions sources, generally speaking, OPGEE estimates are far more complex. For example, the energy consumed in lifting produced fluids—oil, water, and associated gas—to the surface is computed using the fundamental physics of fluid lifting, accounting for friction and pump efficiencies. The UNFCCC and EDGAR do not account for emissions using this approach. Moreover, the emissions are dynamic over time, as fields age and production characteristics change. Most estimates in OPGEE are based on statistical emissions distributions derived from published academic surveys, thousands of measured data points, and other public data sources. A specific and extensive effort was undertaken to build out the methane fugitives model (Rutherford et al., 2021). Numerous studies point to the fact that the U.S. inventory process undercounts its CH_4 emissions from oil and gas supply chain segments, including methane leaks at storage tanks and gathering lines (Yu et al., 2022). Because methane is weighted according to its higher GHG potential, when CH_4 is underestimated, so will CO_2 equivalent emissions.

Methodology comparisons are further complicated by the different ways in which countries report their emissions to the UNFCCC. In the transport sector, emissions from oil and gas transport - whether by pipeline or tanker - are not disaggregated and are difficult to add back into the production emissions estimate. OPGEE, on the other hand, includes oil transport to the refinery and gas transport to distribution in its asset-level emissions estimates.

Methodology comparisons also depend on the global warming potential (GWP) used to quantify the combined impact of CO2 and other GHGs, most importantly in this sector, CH4 emissions. When selecting a GWP to equate emissions of short-lived climate pollutants like methane into equivalent mass of carbon dioxide, the choice of timescale matters significantly (i.e., 100 vs. 20 year). Today's inventories use a 100-year timeframe; this GWP is inappropriate for methane, given its atmospheric lifetime of just twelve years. The Climate TRACE inventory offers the opportunity to express total emissions in both 100- and 20-year equivalency. Using a CO2-equivalent 20-year metric places a stronger near-term emphasis on reduction of short lived climate pollutants and can signal to policymakers, industry, and other stakeholders the climate benefit of prioritizing methane emissions mitigation.

Figure 13 highlights the importance of Climate TRACE's novel method of incorporating satellite evidence of methane superemissions into its estimation approach in geographies like Turkmenistan. Climate TRACE estimates emissions to be between 140 Mt to ~160 Mt CO_2e in the 100-year GWP for years 2015 to 2021. Other inventories report emissions between 20 to 60 Mt; this is higher than other inventories. Lauvaux et al. (2022) estimate that 1.25 Mt of methane emissions come from ultra-emitting sources each year in Turkmenistan. This is roughly equal to 37 Mt CO_2e in the 100-year GWP, or the entire UNFCCC or EDGAR inventory for the country as displayed in Figure 13. These two inventories are unlikely to capture such large emission events in their current accounting as described above.

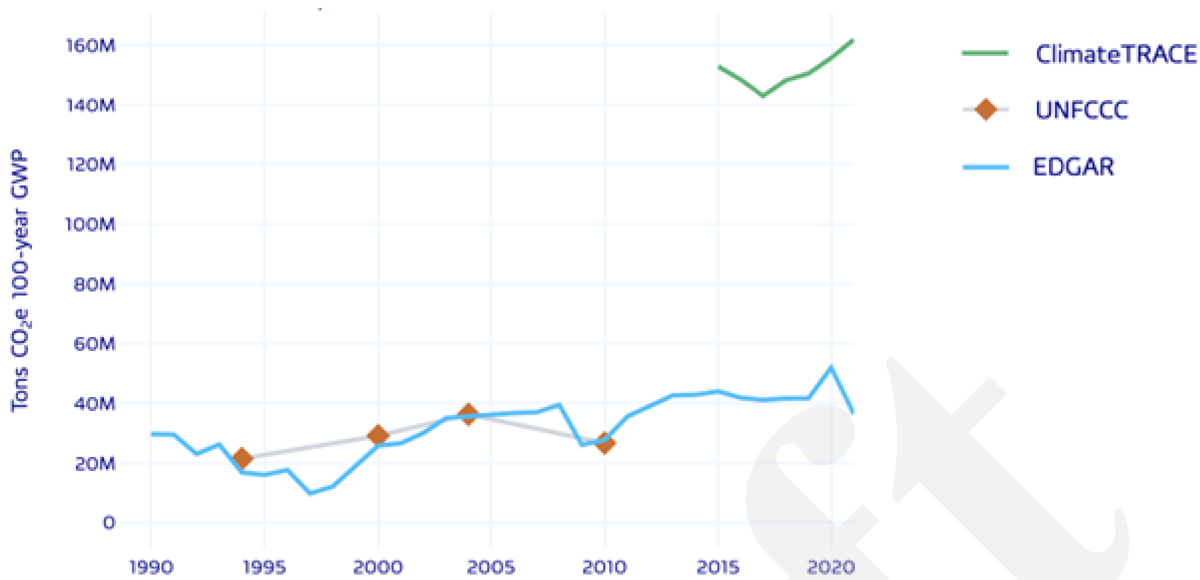

Figure 13 Comparison of tCO_2e (100 year) estimates for Turkmenistan by inventory. Climate TRACE (green lines), UNFCCC (orange dotted gray line).

5. Limitations

While remote sensing, data inputs, and ground truth data are sourced globally, data availability, quality and uncertainty across countries is uneven. For example, while VIIRS flaring volumes are available globally, North America has been relatively more heavily studied when it comes to fugitive methane emissions in certain subsectors and is more data rich compared to other regions. Moreover, worldwide knowledge around the magnitude, distribution, and duration of large emission events (e.g., upstream purposeful venting) is poor. The lack of global data coverage may result in estimates that are not representative in certain geographies (too high or too low). While not available in the current version of Climate TRACE, future versions of the platform will offer an uncertainty range in emissions, as well as an assessment of data availability in each country where an estimate is available. This will help prioritize how to fill gaps on a country-by-country basis.

6. Conclusion

To chart a clean energy transition, we must bring transparency to emission-intensive sectors like oil and gas. For production and refining, the Climate TRACE platform bolsters accountability that is currently lacking when countries self-report their emissions and offers all countries access to reliable, accurate, and timely emissions data across sectors. The information can empower leaders to pinpoint where efforts should be channeled to maximize impact.

More information and techniques will be applied to improve and refine our oil and gas sector emission estimates. For the OPGEE upstream model, we will continue to collaborate with our Stanford University partners to advance the model coding, improve flexibility, and prepare it to intelligently incorporate new sources of ground-truth data. We will boost country coverage percent of country assets modeled) to reduce scaling error, where possible, and highlight data gaps by advocating for improved data availability with stakeholders in specific geographies.

Since empirical measurements cannot be made over all facilities, in all geographies, all the time, this will require improving our models' capabilities to make smarter assumptions in data-poor environments. This includes the integration of current and emerging remote sensing technologies that have the capabilities to assess GHGs from oil and gas systems, including AVIRIS-NG, Carbon Mapper, MethaneSat, TROPOMI, and GOSAT. No singular remote sensing system can overcome all the hurdles to capturing the majority of GHG emission sources, but combining different technologies can work towards high resolution measurements, with credible verification and transparency, at scale. A promising future of emissions monitoring lies in a layered system that integrates a suite of measurement technologies, models, and reported data.

Acknowledgements
Special thanks to our partners at Climate TRACE, Development Seed, Carbon Mapper, Stanford University, the University of Calgary, NASA - Carbon Monitoring System, Colorado School of Mines, and Harvard University that helped with developing the models we deployed, building web tools to share results with public audiences, constructing this document, and working with us to integrate other approaches to and knowledge of oil and gas emissions into these estimates.

Supplemental section metadata

The country level files for the oil and gas production and transport sector include scaled-up estimates of CO_2 and CH_4 emissions, as well as carbon dioxide equivalencies. Countries that have a null value indicate that we did not model any assets in that country, though we know there is some degree of oil and gas production in that country. Countries that have a zero value for emissions indicate that there is no oil and gas production in that country.

The field level asset data file includes estimates of CO_2 and CH_4 emissions, as well as carbon dioxide equivalencies for aggregated oil and gas field assets. Field level assets in the United States field level assets were aggregated up from sub-field level assets and are more representative of emissions from an entire basin. The sub-field level asset file includes disaggregated oil and gas field emissions in the United States only. No sub-field level emissions were provided for outside the United States.

Emissions data are all freely available on the website. All inputs to the OPGEE model, with the exception of production volumes, are available by request. Emissions estimates broken out by supply chain segment (e.g., drilling, extraction and production, surface processing, etc.) are available by request.

Table S1 General dataset information for "asset-climate-trace_oil-and-gas-production-and-transport-field" and "asset-climate-trace_oil-and-gas-production-and-transport-sub-field"**.**

General Description	Definition
Sector definition	*Oil and gas production and transport- including drilling, extraction, production, surface processing, maintenance, waste disposal, pipeline transport, LNG, and crude shipping*
UNFCCC sector equivalent	*1.B.2.a.i Exploration* *1.B.2.a.ii Production* *1.B.2.a.iii Transport* *1.B.2.c Venting and Flaring* *1.B.2.b.i Exploration* *1.B.2.b.ii Production* *1.B.2.b.iii Processing* *1.B.2.b.iv Transmission and Storage* *1.A.1.c.ii Oil and Gas Extraction*
Temporal Coverage	*2015 – 2022*
Temporal Resolution	*Annual*
Data format(s)	*CSV*
Coordinate Reference System	*EPSG:4326, decimal degrees*
Number of assets/countries available for download and percent of global emissions (as of 2022)	*1,910 oil and gas fields representing 73% of this sector's emissions*
Total emissions for 2022	*17,908,563,079 tonnes CO2e 20yr GWP*
Ownership	*We used ownership data provided by Rystad*
What emission factors were used?	*The OPGEE model used to produce emissions is an engineering-based model that accounts for reservoir characteristics and site operations*
What is the difference between a "NULL / none / nan" versus "0" data field?	*"0" values are for true non-existent emissions. If we know that the sector has emissions for that specific gas, but the gas was not modeled, this is represented by "NULL/none/nan"*

total_CO2e_100yrGWP and total_CO2e_20yrGWP conversions	Climate TRACE uses IPCC AR6 CO_2e GWPs. CO_2e conversion guidelines are here:https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FullReport_small.pdf

Table S2 Asset level metadata description confidence and uncertainty for "asset-climate-trace_oil-and-gas-production-and-transport-field" and "asset-climate-trace_oil-and-gas-production-and-transport-sub-field"**.**

Data attribute	Confidence Definition	Uncertainty Definition
type	Low = little knowledge of characteristics of asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
capacity_description	NA	NA
capacity_factor_description	NA	NA
capacity_factor_units	NA	NA
activity_description	NA	NA
CO2_emissions_factor	Low = little knowledge of characteristics of asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
CH4_emissions_factor	Low = little knowledge of characteristics of asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
N2O_emissions_factor	NA	NA
other_gas_emissions_factor	NA	NA
CO2_emissions	Low = little knowledge of characteristics of asset; low number of inputs for modeling	Not provided

	Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	
CH4_emissions	Low = little knowledge of characteristics of asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
N2O_emissions	Low = little knowledge of characteristics of asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
other_gas_emissions	NA	NA
total_CO2e_100yrGWP	Low = little knowledge of characteristics about asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided
total_CO2e_20yrGWP	Low = little knowledge of characteristics about asset; low number of inputs for modeling Medium = moderate knowledge of characteristics of asset; medium number of inputs for modeling High = good knowledge of characteristics of asset; high number of inputs for modeling	Not provided

Data citation format:
Schmeisser, L; Wang, R; Tecza, A; Huffman, M; Schadel, S; Bylsma, S; Hansen, J; Schmidt, Z; Conway, TJ; and Gordon, D (2023). *Oil and Gas Production and Transport Emissions,* RMI, USA, Climate TRACE Emissions Inventory. https://climatetrace.org [Accessed date]

Geographic boundaries and names (iso3_country data attribute): The depiction and use of boundaries, geographic names and related data shown on maps and included in lists, tables, documents, and databases on Climate TRACE are generated from the Global Administrative

Areas (GADM) project (Version 4.1 released on 16 July 2022) along with their corresponding ISO3 codes, and with the following adaptations:

- HKG (China, Hong Kong Special Administrative Region) and MAC (China, Macao Special Administrative Region) are reported at GADM level 0 (country/national);
- Kosovo has been assigned the ISO3 code 'XKX';
- XCA (Caspian Sea) has been removed from GADM level 0 and the area assigned to countries based on the extent of their territorial waters;
- XAD (Akrotiri and Dhekelia), XCL (Clipperton Island), XPI (Paracel Islands) and XSP (Spratly Islands) are not included in the Climate TRACE dataset;
- ZNC name changed to 'Turkish Republic of Northern Cyprus' at GADM level 0;
- The borders between India, Pakistan and China have been assigned to these countries based on GADM codes Z01 to Z09.

The above usage is not warranted to be error free and does not imply the expression of any opinion whatsoever on the part of Climate TRACE Coalition and its partners concerning the legal status of any country, area or territory or of its authorities, or concerning the delimitation of its borders.

Disclaimer: The emissions provided for this sector are our current best estimates of emissions, and we are committed to continually increasing the accuracy of the models on all levels. Please review our terms of use and the sector-specific methodology documentation before using the data. If you identify an error or would like to participate in our data validation process, please contact us.

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