Oil & Gas sector: Production, Processing, Refining, 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 transporting 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 oil and gas system methane 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 or "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 two 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.

Climate TRACE uses a hybrid model, the Oil Climate Index + Gas (OCI+), to generate global emissions estimates for carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Specifically, Climate TRACE relies on two of the OCI+'s underlying models–the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) and The Petroleum Refinery Life-Cycle Inventory Model (PRELIM)–to assess the upstream (production) and midstream (refining) portions of the petroleum lifecycle, respectively. OPGEE was developed by a team from the California Air Resources Board and Stanford University (Brandt et al., 2021). PRELIM was developed by a team from the University of Calgary (Jing et al. 2020). Both OPGEE and PRELIM have been peer-reviewed and used internationally by policymakers (Masnadi et al., 2018; Jing et al., 2020). Through the use of novel analyses of remote sensing data to generate inputs for OPGEE and PRELIM, 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. OCI+'s midstream component, PRELIM, provides an estimate of the emissions and product slate volumes from refineries per barrel of crude. The model covers fugitive and exhaust emissions derived from combustion-related refining processes for a variety of crude oils and refining configurations.

It should be noted that while the Oil and Gas Products Emissions Module (OPEM) is also a part of the OCI+, it was not included in Climate TRACE's model for this sector. OPEM describes downstream (end-use transport and consumption) emissions, which are encompassed by other Climate TRACE sectors. Figure 1 provides a flowchart of the relationship between the OPGEE and PRELIM models and how their inputs and outputs feed into each other.

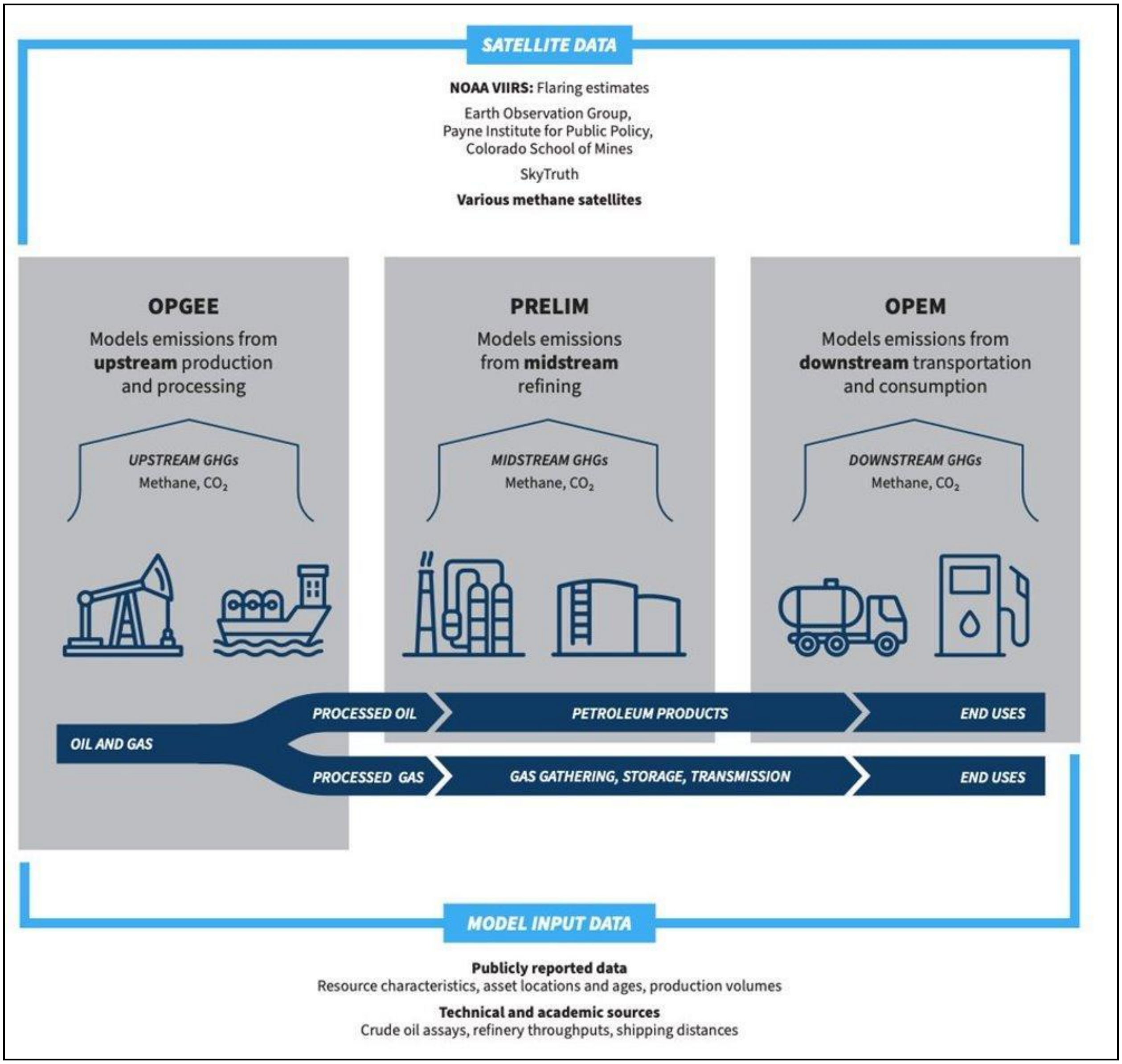

Figure 1 The OCI+ quantifies GHGs from the upstream, midstream, and downstream components of the petroleum lifecycle. The upstream and midstream portions, OPGEE and PRELIM, were used in Climate TRACE's models for oil and gas production, transport, and refining. Here, "upstream" refers to drilling, extraction, 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 used OPGEE and PRELIM to model global oil and gas fields and refineries, hereafter identified as "assets". These "asset-level" results were then used to model country-level emissions. Climate TRACE relied on both bottom-up ground truth 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. The PRELIM approach to estimate oil refining is described in section 5, followed by the PRELIM modeling results in section 6.

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

3.1 Asset Definition

Oil and gas fields. Oil and gas production assets were defined and selected by their unique names and, in most cases, matched to shapefiles provided by the Rystad Energy UCube dataset (https://www.rystadenergy.com/). These shapefiles 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 asset-level assessment, field-level emissions were generated for about 550 oil and gas fields globally, representing about two-thirds of global production. The assets span about 90 countries; 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.

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, that 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 required 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.
- **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

3.3.1 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 Ground truth data employed 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

3.3.2 Remote sensing datasets

In addition to ground truth and activity data, Climate TRACE used remote sensing data to estimate two other key inputs for OPGEE: flaring volumes and super emitter events.

3.3.2.1 VIIRS Gas Flaring

To estimate flaring volumes, we used the Visible Infrared Imaging Radiometer Suite (VIIRS) derived Gas Flaring product. VIIRS detects global gas flaring at 750m 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 are 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/)

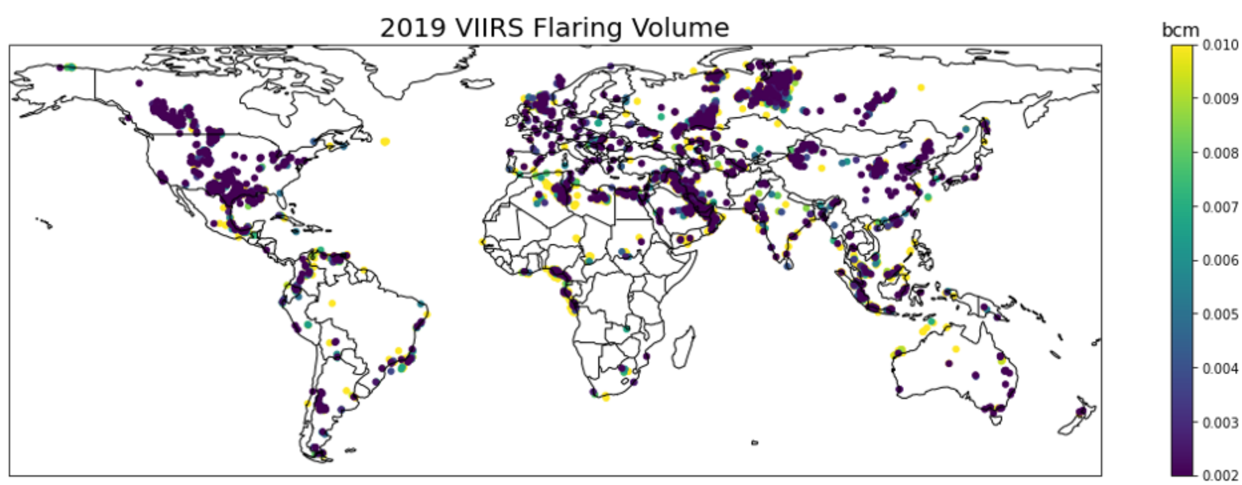

Figure 2 2019 VIIRS flaring volumes in billions of cubic meters (bcm).

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 liquified natural gas (LNG) transport facilities (Elvidge et al., 2015). This flaring process produces both CO_2 and CH_4 (unburned gas), 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, RMI quantified these emissions and produced a derived modeling metric, the flaring-oil-ratio (FOR, units of standard-cubic-feet to barrel-of-oil-equivalent or scf/bbl), which related 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.

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 Cube (this includes almost all fields outside of the U.S., as well as California). Any flares that fell within the polygon 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.), any flares that fell within a radius of 10 miles of the field were 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. Figure 3 details the flaring geolocation matching approach.

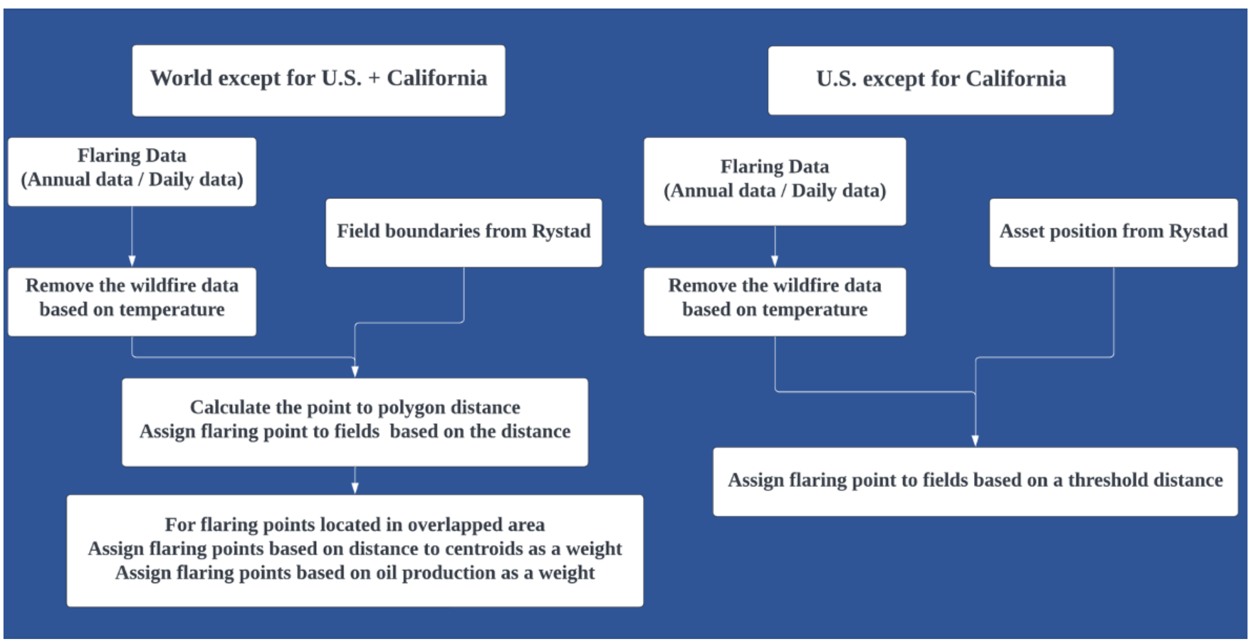

Figure 3 Approach to assign VIIRS flaring data to oil and gas assets based on the "World, except for U.S., and California" and "U.S. except for California".

3.3.2.2 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) showed 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 4). Similarly, gas transmission pipeline fugitive loss rates were adjusted for all assets in Russia and Turkmenistan.

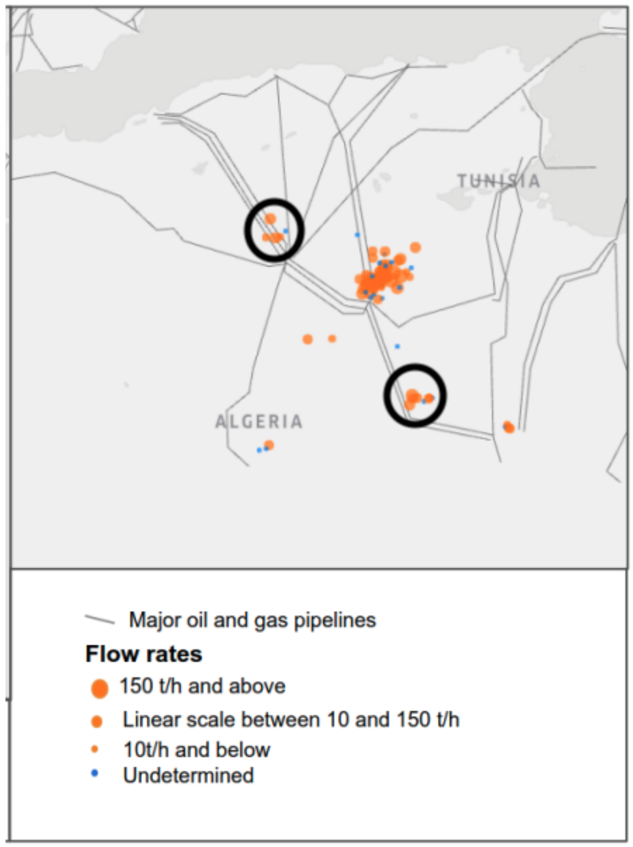

Figure 4 Methane emission detections (orange dots) over Algeria, from Lauvaux et al. (2022), overlaid with approximate locations of Hassi R'Mel and Tin Fouye fields (black circles).

Figure 5 shows the effect on methane emissions results from adjusting OPGEE's fugitive methane loss rates for three assets in Algeria, Turkmenistan, and the United States. 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).

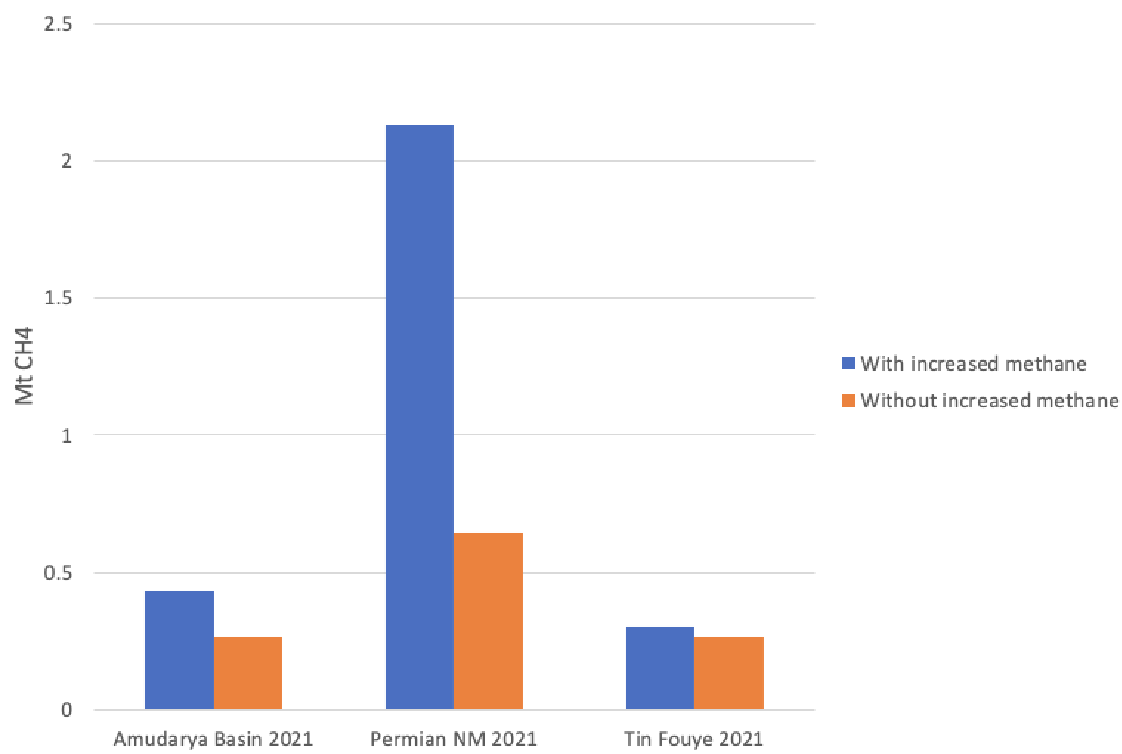

Figure 5 2021 methane estimates from three assets - Amudarya Basin, Permian NM, and Tin Fouye - before (orange) and after (blue) adjusting OPGEE's inputs for fugitive methane loss.

3.4 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 outputted 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. 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, Mexico and the Permian New Mexico asset.

Model outputs and barrel of oil equivalency (BOE). Oil and gas field inputs were specified based on the datasets in section 3.3.1. 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 (gCO2e/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 (kgCO2e/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) 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).

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 (84F). Water reinjection practice was turned on, and water-to-oil-ratio (WOR) was calculated by dividing the gas-to-oil-ratio (GOR) by 1000.

Additional special cases. For Norwegian fields Gudrun, Johan Sverdrup, Gjoa, and Trull, 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 Country-level estimation

Country-level estimates for methane 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. This process ensures that a country's total emissions can be estimated, even if not 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). Figure 6 shows the distribution of asset-level coverage for the top emitting countries by year. For example, Russian assets included in the Climate TRACE dataset represent about 60 percent of Russia's total Oil and Gas Production and Transport emissions.

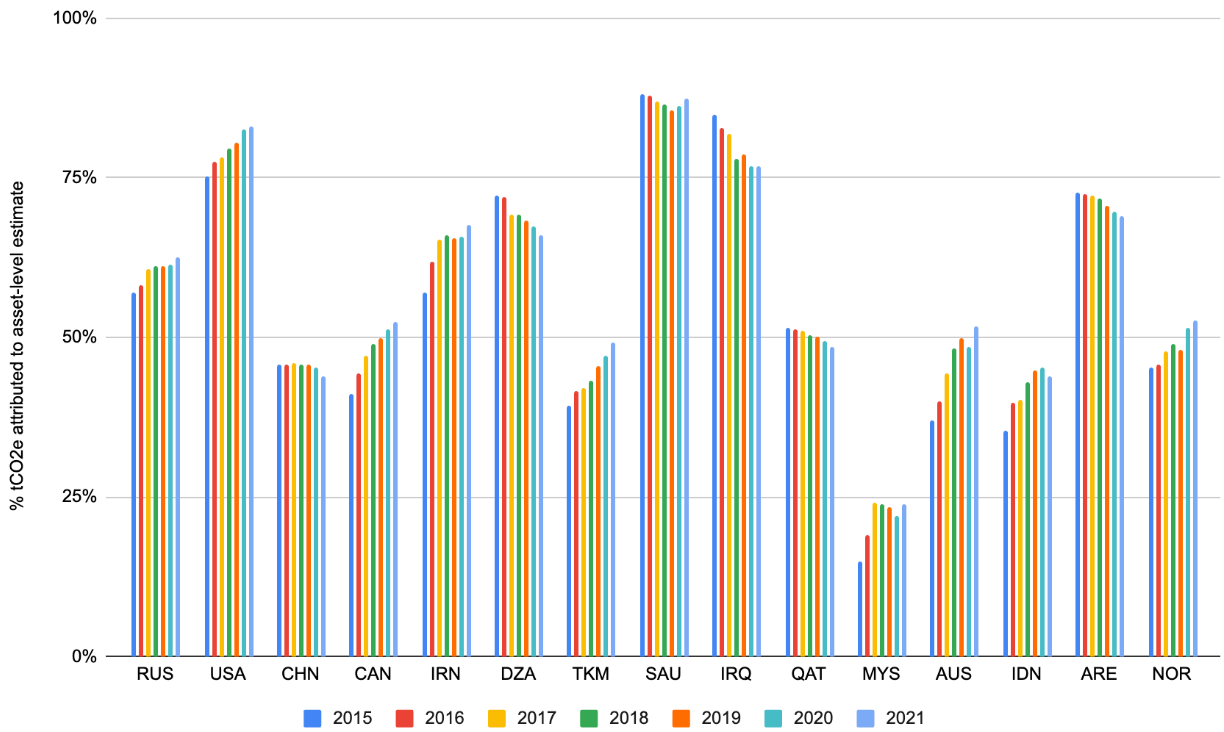

Figure 6 Asset-level coverage for the top 15 country emitters in the Climate TRACE Oil and Gas Production and Transport dataset. Bars reflect the percent of country-level emissions attributed to identified assets, as opposed to estimates based on the country's production-weighted average, for years 2015 to 2021.

4. Results: Oil and Gas Production and Transport

Figure 7 shows the top 10 countries with highest emissions from the oil and gas production and transport sector. Russia and the USA have particularly high emissions, more than double that of the third highest emitting country for most years analyzed.

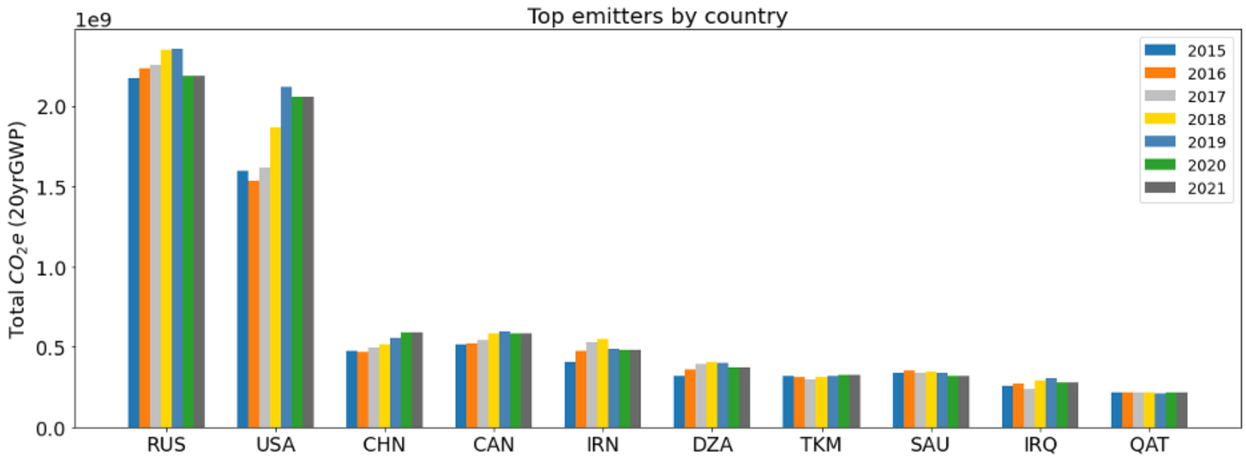

Figure 7 Top 10 global oil and gas production and transport emitters, for years 2015-2021. The y-axis unit of measure is billion tonnes of CO_2e 20 year global warming potential (GWP).

Figure 8 shows the top flaring countries by volume for modeled assets. Countries that flare high volumes of gas, such as Russia, Iraq, Iran, and the USA, are also amongst the top overall emitters in Figure 7. Notably, Canada is the fourth largest overall emitter due to its high volumes of production but does not have high flaring volumes. Flaring inefficiencies also contribute to overall methane emissions--in our analysis this was about 10 percent.

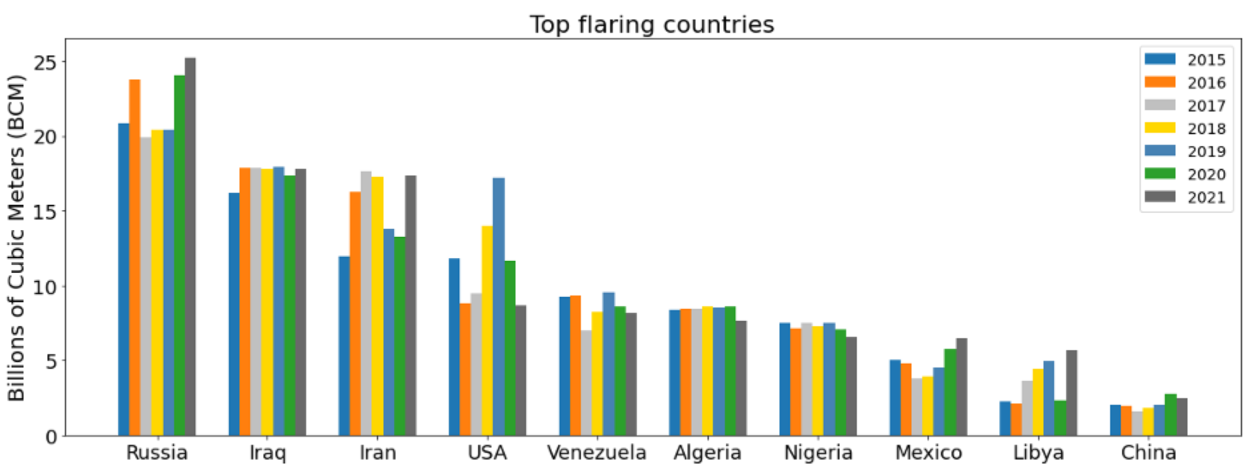

Figure 8 Top 10 countries by flaring volume (bcm) for years 2015 to 2021.

Figure 9 shows the top 10 ranked assets by methane intensity, in tonnes of methane per barrel of oil equivalent. On a per product basis, these oil and gas fields emit the most methane. However, they are not always top emitting assets on an absolute basis if they are not high-producing. In 2021, the Brent oil field in the UK emitted the most methane per barrel of oil produced, which was a striking difference from previous years' emissions intensity at that location. This field is a poignant example of how changes in oil characteristics and/or processing techniques over time can have a very large impact on emissions from a given asset.

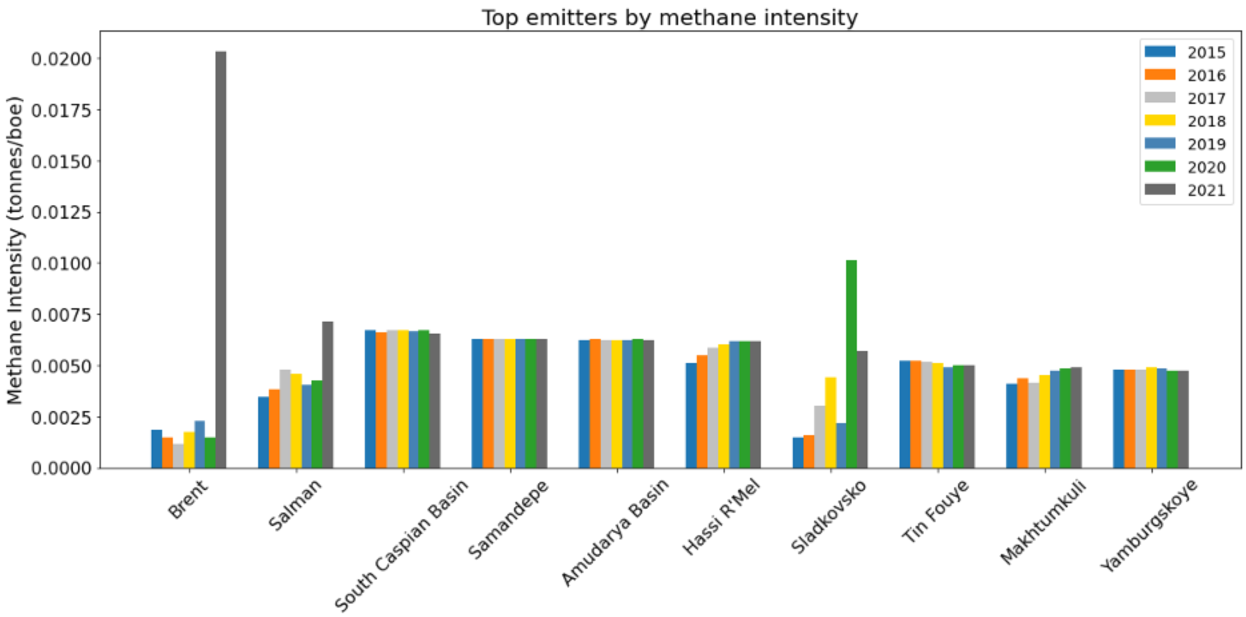

Figure 9 Top 10 ranked asset emitters by methane intensity in tonnes per barrel of oil equivalent (tonnes/boe) for the oil and gas production and transport sector, for years 2015 to 2021.

Figure 10 shows the top 10 assets with the highest gas flaring volume during the dataset time series. Flaring-related combustion emissions tend to dominate the emissions profile of assets with high flaring.

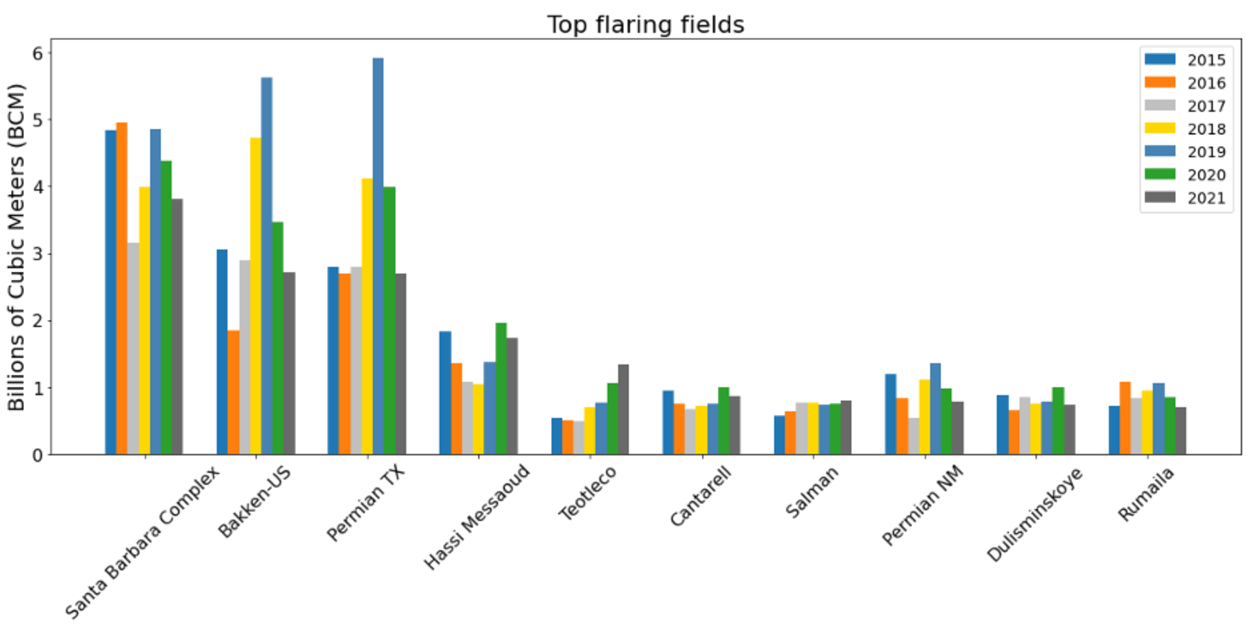

Figure 10 Top 10 oil and gas fields with highest flaring volume (bcm) for years 2015 to 2021.

4.1 Comparison with Other Emissions Inventories

Our asset-level emissions intensities were checked 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.

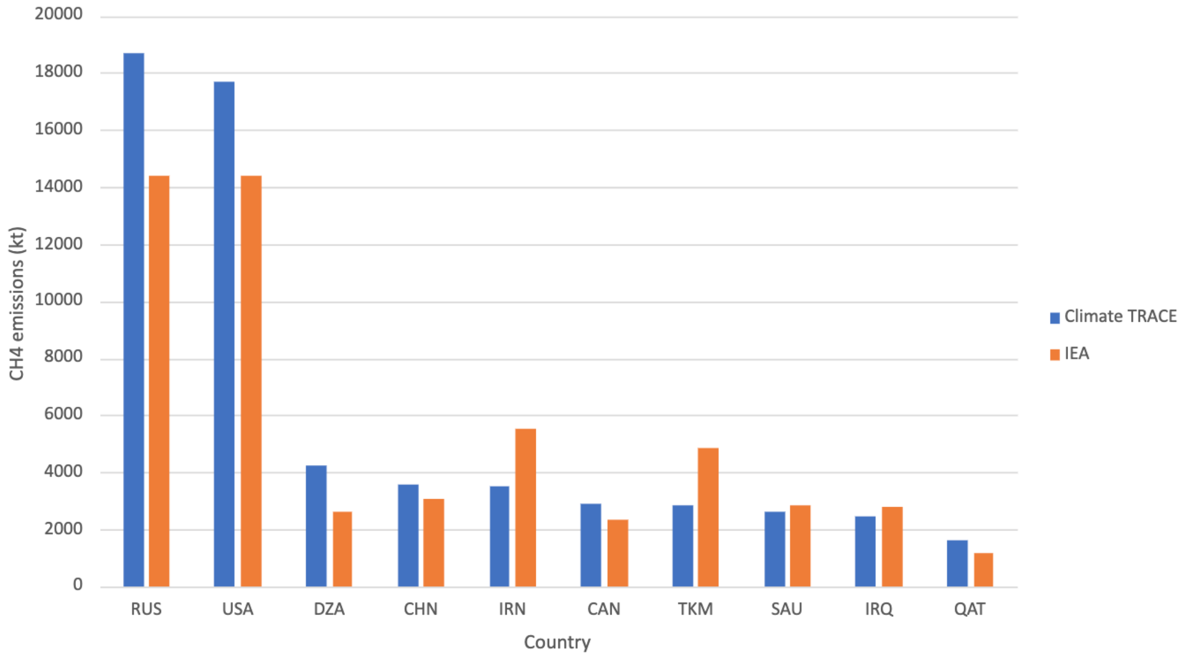

Figure 11 Top 10 global methane emitters, comparison with IEA Methane Tracker 2021.

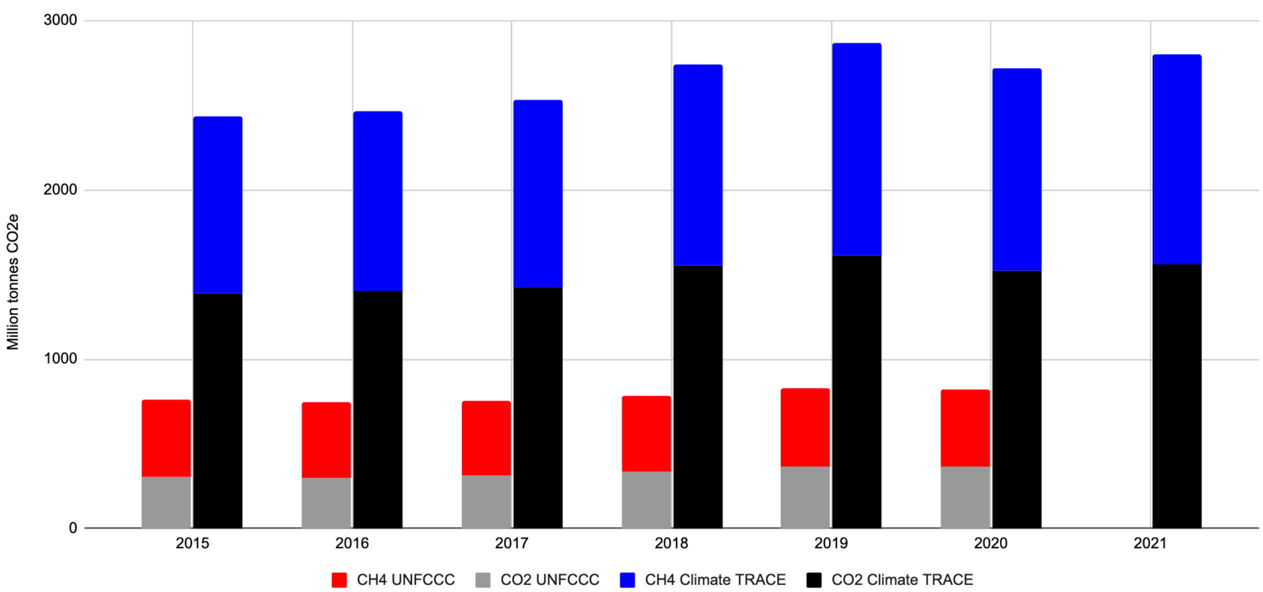

Figure 12 Comparison of CO_2 and CH_4 estimates for UNFCCC Annex 1 countries (100 year GWP). Comparison includes 19 countries for which comparable UNFCCC data was available, including Russia, U.S.A., Australia, Bulgaria, Canada, Germany, Denmark, Spain, France, U.K., Greece, Croatia, Italy, Japan, Kazakhstan,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

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; 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.

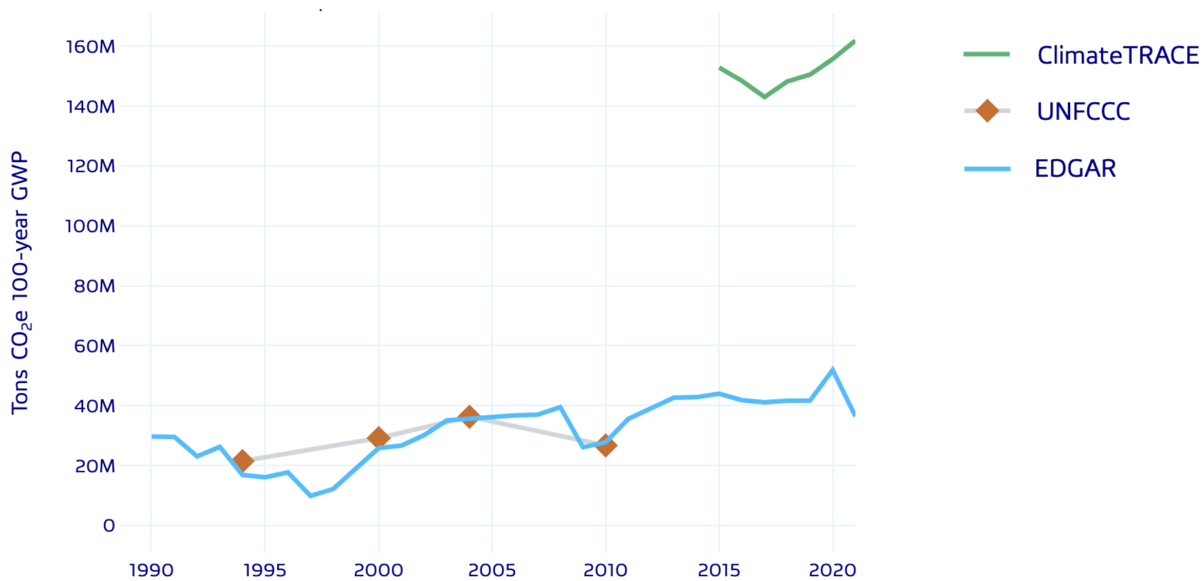

Figure 13 Comparison of tCO_2e (100 year) estimates for Turkmenistan by inventory. Climate TRACE (green lines), UNFCCC (orange dotted gray line).

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 (Figure 12, Figure 13); 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.

5 Materials and Methods: PRELIM - Oil Refining Emissions

5.1 Asset Definition

Refineries. Refineries are major industrial sites, responsible for turning crude oil and gas pumped out of the Earth into the major fuels and feedstocks that underpin transportation (including gasoline, diesel, and jet fuel), heating/cooling, and everyday products. In our emissions estimates, transportation of crude oil to the refinery, and transportation of products to their end-use locations, were excluded. We estimate emissions of the refining process itself using onsite crude oil.

5.2.1 PRELIM model

Climate TRACE uses the PRELIM model to generate refinery-level emissions estimates using refinery type-specific intensities and estimated throughputs.

PRELIM is a crude refining process model that provides an estimate of the emissions and product slates volumes from a refinery per barrel of crude. PRELIM was developed by a team from the University of Calgary (Jing et al., 2020). The model covers fugitive and exhaust emissions derived from combustion-related processes of refining a variety of crude oils within a range of configurations in a refinery; depending on the settings used, it can also include indirect emissions embodied in consumed electricity generated off-site.

5.2.2 Gases

In addition to CO_2 , CH_4, and N_2O, PRELIM also assesses particulate matter and other localized pollutants. However, absolute volumes of these trace gases could not be easily teased apart for this analysis, and localized pollutants are important for health concerns but outside the scope of 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.

5.2.3 Key Inputs

To estimate total emissions from the refining process, PRELIM required some key inputs to establish the parameters of the model. Prior research has demonstrated emissions results to be sensitive to these inputs. Key inputs include:

- **Crude Assays**. PRELIM includes an assay library of over 600 crude oils from around the world. Assays contain information about the specific chemical properties of each oil, including details on API gravity, sulfur, nitrogen and hydrogen content, volume/mass flow (% recovery), Micro-carbon residue or Conradson carbon residue, and Viscosity (cST at 100 °C) for vacuum residuum. These chemical characteristics influence the processes, energy, and climate impact required to turn each different source of crude into useful products.
- **Refinery Configuration.** Refineries around the world are configured to process a mix of crude oil and produce a certain mix of products. These configurations are defined by different combinations of process units, which turn crude oil and its derivatives into useful products. Different configurations are required depending on the type of crude being processed, and the desired mix of end products for the consuming region. Configuration has a very large impact on emissions. Generally speaking, a more complex refinery has more units, and is designed to create a wide range of end products using a

heavier mix of crude oil. These more complex refineries are more emissions-intensive as a result. On the other hand, simpler refineries have fewer units and process lighter crude, resulting in a less emissions-intensive climate footprint.

- **Other Settings.** PRELIM allows for user control with many settings, but it can also choose smart defaults based on the primary inputs of crude assays and configurations. These include different options for many refining processes: naphtha catalytic reforming, FCC hydrotreaters, electricity sources, SMR hydrogen reforming, and many more. We use PRELIM defaults for these inputs, as data availability globally is challenged for these details.

PRELIM provides emissions intensities per barrel based on these and other inputs, and those per barrel figures are multiplied by our throughput estimates (explained below) to achieve annual emissions estimates for each refinery in our coverage. Climate Trace refinery emissions modeling does not trace individual barrel supply chains from field to specific refinery. Rather, it provides an estimate of the likely refinery complexity and associated emissions based on the crude oil properties.

5.3 Datasets

Many publicly reported, technical, and academic sources served as ground truth and activity data for PRELIM. Data availability on refinery throughput, capacity, configurations and locations varies significantly by geography, so our approach varies for non-US refineries and US refineries. Table 2 summarizes key input data sources for PRELIM. All datasets are openly available.

Table 2 Ground truth data employed as inputs to the PRELIM model.

PRELIM Model Inputs for Oil Refining		
Input	**Source**	**Regions**
Estimate throughput at non-US refineries	BP Statistical Review of World Energy 2022	Global
Acquire information on US refinery capacities, configurations, and locations	US Energy Information Agency (EIA): Refinery Capacity Report, and US Energy Atlas	U.S.A.
Acquire information on US refinery capacities, configurations, and locations	A large number of company websites, government websites, news articles, and press releases. Global Energy Observatory (GEO).	Global

5.4 Method

Refineries around the world are built in different configurations, designed to intake a certain type of crude oil, and produce a certain mix of gasoline, diesel, and other products (with limited flexibility in both inputs and outputs). The PRELIM model can be used to estimate emissions per barrel of oil refined, using information about how a refinery is configured and what type of crude oil it processes. Emissions per barrel values can then be multiplied by annual throughput to estimate annual emissions. We follow these general steps for each refinery in our dataset, estimating CO_2, CH_4, N_2O, and CO_2e emissions globally.

Data availability varies significantly by geography, so our data and approach varies for non-US refineries and US refineries.

For non-US refineries, we assigned each refinery to one of three configuration categories: hydroskimming, medium conversion, or deep conversion. Refineries in each configuration category generally have similar types of equipment, designed to process similar types of crude oil. We used PRELIM to generate an average emissions intensity for each refinery category, based on its configuration and that configuration's likely crude slate. For example, an average hydroskimming refinery emissions intensity value was generated by running a number of compatible light crudes through a hydroskimming configuration in PRELIM. The exercise was repeated for the other configuration categories: medium crudes processed by a medium conversion configuration, and heavier crudes processed by a deep conversion configuration. We estimate throughput using each facility's capacity, multiplied by country-level utilization by year. Country-level utilization by year was calculated using throughput and capacity data from the BP Statistical Review of World Energy 2022. Finally, the throughput values were multiplied by emissions intensity to generate annual emissions for each refinery per year.

US refineries followed a similar process, but increased data availability allows for more granularity to define eight configuration categories. These are more detailed sub-categories of the hydroskimming, medium conversion, and deep conversion categories used globally. For crude type, we categorized what type of crude is typically run by each refinery, "Medium Sour" for example. We then combined crude category with configuration category and estimated emissions intensity for each refinery using PRELIM. To estimate throughput, we used refinery-level capacity, combined with regional utilization data, both provided by the EIA. The throughput was then multiplied by emissions intensities to generate annual emissions estimates for each refinery modeled per year.

Our country-level estimates were generally the sum of asset-level estimates. In most countries, we covered substantially all refinery capacity, and a simple sum represents the country as a whole. However, in China, we excluded sub-100 thousand of barrels per day (kbd) refineries from our asset-level data due to difficulties in obtaining open-sourced information about their capacities, configurations, and locations. Therefore, our China country-level estimate was the sum of our asset-level estimates, scaled up by 20% to account for missing capacity, ~14.16 million barrels per day (mmbd) of Chinese capacity in our asset-level data, versus ~16.99 mmbd according to BP Statistical Review of World Energy (2022).

6. Results: Oil Refining

Figure 14 shows the top 10 global refining emitters for all years analyzed, 2015 to 2021. As in the oil and gas production and transport sector (Figure 7), the USA shows up again as a high emitting country in the refinery sector, again more than double the third highest emitter (India) for most years. To put this sector into context, the emissions from refineries in the USA are nearly equivalent to the emissions from all Climate TRACE sectors in the Netherlands, as shown by the dashed line in Figure 14.

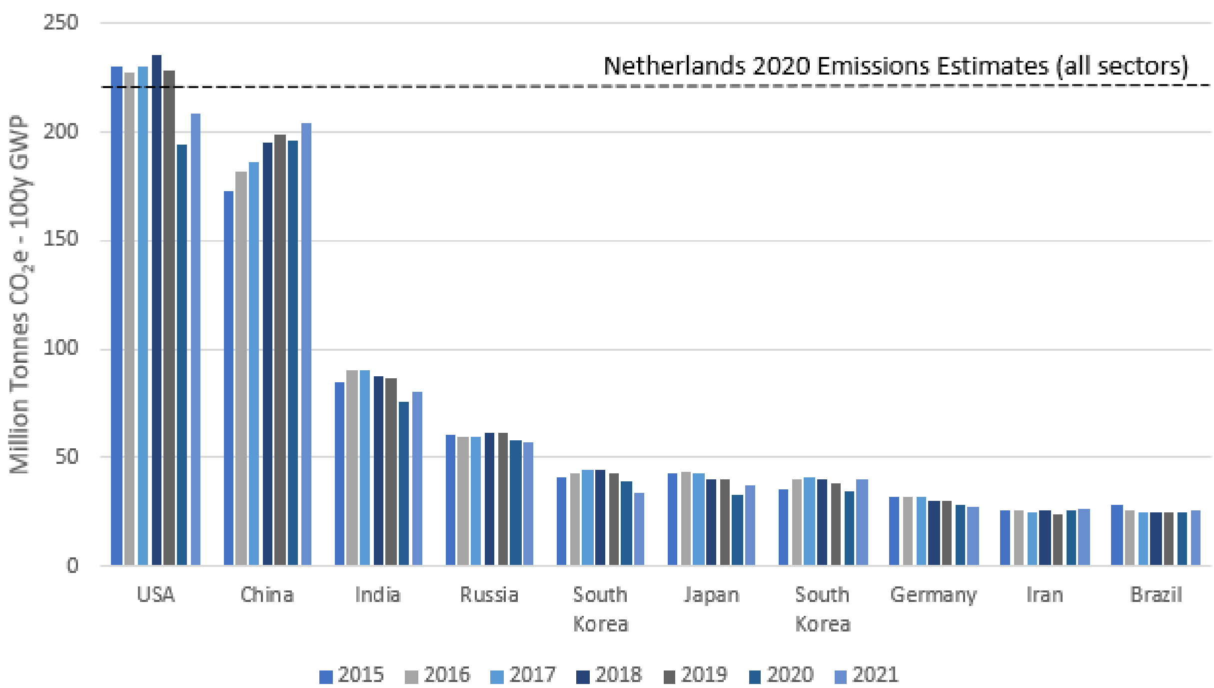

Figure 14 Top 10 global oil refining emitters, 2015-2021. Netherlands 2020 emission estimate (country-level total including all sectors measured by Climate TRACE) included for context.

In the refining sector, Unlike the UNFCCC, and EDGAR, which generally apportion total fuel use to each sector and multiply by emission factors, PRELIM uses a systems-level approach and refinery linear modeling methods. This approach includes details for particular crude intake and refinery configurations down to the sub-process level, and uses publicly available information whenever possible. While emission factors are used for some emissions sources, generally speaking, PRELIM modeling is far more complex and flexible than traditional emissions factor approaches. The model allows for flexibility in crude slate (the type of crude processed), configuration (which units are present and used to produce a certain mix of products like gasoline), and many other inputs. A large, public database of crude assays, and flexibility in configuration settings allows users to emulate a refinery based on those key characteristics.

Academic literature around refinery emissions has historically focused on local pollutants due to well-documented air quality concerns. The production sector outlined in section 3 is currently further along regarding remote sensing studies of key climate pollutants like methane. This is partly motivated by the fact that most methane super-emitter events detected so far have been in the production sector, while equipment further downstream is generally more consolidated and well-maintained. While upstream has been the focus so far, remote sensing emissions studies, regarding methane in particular, are beginning to cover the refining sector as well. A recent study by Lavoie et al. (2017) analyzed a sample of US refineries using aircraft detections, which suggested that refinery methane emissions were roughly 7.5 times higher than reported inventories. Additionally, it is likely that emissions (especially CO_2, but also CH_4) from offsite power generation and offsite hydrogen production are under-counted in national inventories, as they can be omitted or end up in other reporting categories. Our estimation approach differs considerably from traditional emissions factor approaches, incorporating significantly more detail, and resulting in significantly different estimates as shown in Figure 15, which compares Climate TRACE oil and gas estimate to other inventories.

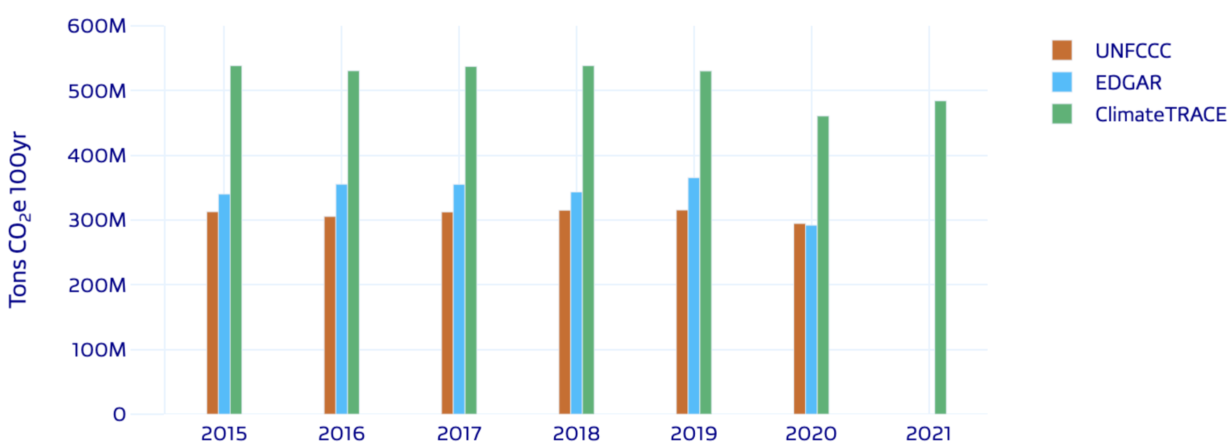

Figure 15 Comparison of global tCO_2e (100 year) estimates in the refining sector. UNFCCC (brown bars), EDGAR (blue bars), and Climate TRACE (green bars) inventories are shown.

The combination of CH_4 leaks and likely missing or undercounted CO_2 emissions due to reporting issues results in a significant difference in our modeling estimates compared to other inventories. Because methane is weighted according to its higher GHG potential, when CH_4 is underestimated, so will CO_2 equivalent emissions.

7. Discussion: Oil and Gas Production, Transport, and Oil Refining

The methods and results presented here summarize emissions from both the oil and gas production and transport sector, as well as the refining sector. We show that these oil and gas activities contribute massive amounts of greenhouse gas emissions each year, with a large range in variability between country level totals and between asset level totals. Emissions intensity numbers show that different oil and gas characteristics, as well as different processing techniques and operating practices, can markedly affect the amount of emissions per barrel of oil equivalent produced.

The use of the OPGEE and PRELIM models enables transparent, granular asset emissions data (e.g., field- and refinery-level estimates). This level of granularity is not achievable globally by the other approaches. The models deployed by Climate TRACE have the capability to offer breakouts of process- and source-level emissions and to indicate which supply chain segments contribute the most emissions. With this knowledge, TRACE data can serve as a source of comparison and/or help fill knowledge gaps in existing top-down approaches. Over time, the OPGEE and PRELIM models via the OCI+ will also enable differentiation of oil and gas resources for market- and policy-relevant applications. This type of transparency will ultimately be needed to make climate-informed decisions around oil and gas assets and to decarbonize the sector.

Our results show reasonable agreement with some inventories while drawing attention to differences in others. Emission-factor based methods, such as the UNFCCC, and EDGAR, tend to display flatter emissions trends over a time series that don't capture the variability in emissions that can arise from steep changes in production or in characteristics of oil and gas resources. Moreover, several existing inventories are interdependent of one-another (e.g., many utilize IPCC 2006 emission factors). The Climate TRACE approach offers a novel, independent data set that applies and expands upon trusted models with roots in academia and policy.

Importantly, our approach to model oil and gas emissions with OPGEE and PRELIM also demonstrates the ability to improve and incorporate new emissions knowledge as it becomes available. For example, between the first and second iteration of the Climate TRACE inventory, we adopted higher quality model inputs, boosted comprehensiveness in country emissions scaling, and incorporated evidence of satellite methane super-emitting leak detections. The last piece is particularly critical--as the growing array of satellites and other advanced technologies that are capable of detecting methane (a key climate impact driver) from oil and gas systems provide new emissions intelligence, the approaches to emissions assessment at the asset, sub-national, and country level must keep pace.

7.1 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.

8. 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 (% 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. For the PRELIM refining model, we will pursue data necessary to level up from refinery category intensities towards sub-national and refinery-specific estimates (e.g., individual refinery configurations, crude oil assay pairings, temporally granular throughput data).

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.

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