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Supplementary Materials for

Global carbon intensity of crude oil production

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This PDF file includes:

Materials and Methods

Other Supplementary Materials for this manuscript include the following:
(available at www.sciencemag.org/content/361/6405/851/suppl/DC1)

Input Data (Excel), Results Data (Excel), Fig1&2 Data (Excel)

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1. Materials and Methods

1.1. LCA simulator

Due to the challenges of developing of integrated engineering models, previous life cycle upstream oil and gas studies generally estimated energy and environmental indices using "top-down" approaches based on macroeconomic data (*1–10*). However, economic accounting cannot explain underlying physical drivers of energy consumption and emissions from oilfield facilities (*5*, *11*). A more granular, engineering-based "bottom-up" model can address these issues because of the physical insights provided during analysis (*1*). However, bottom-up engineering-based models require intensive data as input parameters that are not always readily available in public literature.

The life-cycle GHG intensities of each field are generated using the *Oil Production Greenhouse Gas Emissions Estimator* (*OPGEE version 2.0*) (*12*), an open-source engineering-based field-specific model. OPGEE software and user guide can be found elsewhere (*12–14*). OPGEE is a peer-reviewed (*1*, *5*, *12*, *15–22*) well-to-refinery (or WTR, including all activities from primary extraction to delivery of crude at the refinery inlet gate) life-cycle analysis (LCA) model developed at Stanford University. It has been used extensively in California's LCFS program (*23*), and has been reviewed in numerous rounds of public regulatory commenting.

Using a "bottom-up" approach, OPGEE makes estimates of emissions intensities using up to 50 parameters as input data for each modeled oilfield. OPGEE includes emissions from exploration, drilling & development, production & extraction, surface processing, maintenance, waste disposal, and crude transport (see Fig. S1). The functional unit (or unit of analysis) is 1 MJ of crude petroleum delivered to the refinery entrance gate. Lower heating value (LHV) is used for all energy calculations. OPGEE estimates emissions using engineering models of production methods (e.g., water flooding), reservoir properties (e.g., pressure and temperature), fluid properties (e.g. crude density), processing practices (e.g., application of acid wet gas removal for associated gas processing), and crude oil transportation (e.g. via ocean tanker or pipeline). See the user guide for more details on physical models of each process stage (*12*).

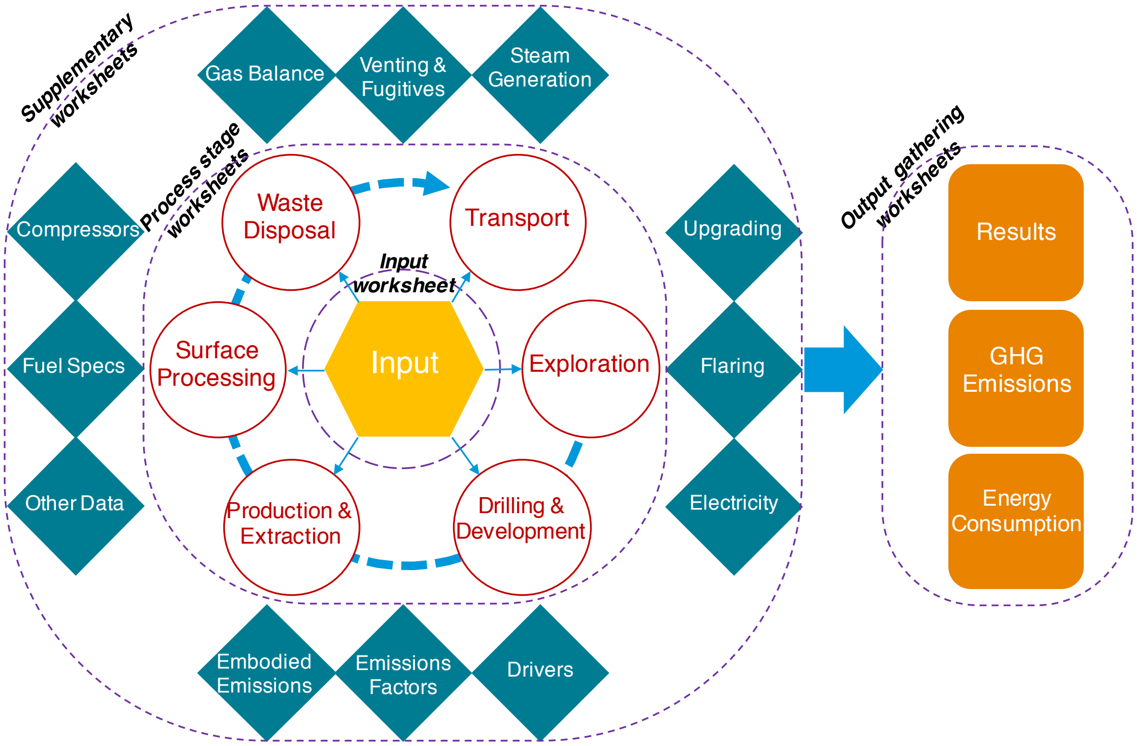

Fig. S1. OPGEE macroscopic structural flow diagram. Input data (center) feed into life-cycle stage worksheets, which themselves rely on supplementary calculation worksheets (outer).

There are different elements of OPGEE that can be advanced in future efforts, e.g.:

- Including additional production technologies like polymer and chemical EOR, miscible hydrocarbon flooding, in-situ combustion, subsurface electric heaters, and cold heavy oil production with sand (CHOPS);
- Creating a comprehensive oil and gas process equipment venting/fugitive database and integrating it with OPGEE: most fugitive and venting emissions in OPGEE are currently calculated using emissions factors derived from California Air Resources Board (ARB) industry survey data (*24*). The data are specific to California where energy and environmental regulations are different than other regions;
- Calculation of field-level flaring rates using high resolution satellite data;
- Pipeline multi-phase flow modelling for more accurate estimation of energy costs;
- Adding comprehensive maintenance and waste disposal models;
- More granular data-driven validation of different process stages of OPGEE;

- Capturing the important cross-country differences by developing regional OPGEE defaults.

It should be noted that there are several emission factors that cannot easily be captured and modeled in OPGEE (e.g. equipment age and maintenance practices, on-site behavior and practices like inspection frequency and detecting/reporting standards) and is left for future research work.

1.2. Definitions and assumptions

1.2.1. GHG emissions

In this manuscript, "GHG intensities" and "carbon intensities (CIs)" are equivalent terminologies with the same unit (g CO_2eq./MJ crude oil produced and delivered at the refinery inlet gate). All presented volume-weighted-average GHG numbers are weighted based on crude oil production (bbl/d).

Greenhouse gases included in this work are: CO_2, CO, CH_4, N_2O, and non-methane volatile organic compounds (NMVOCs) to all air receptacles. GHGs are converted to CO_2eq. using the following global warming potential (GWP) factors based on pulse emissions over a 100-year time frame – AR5/GWP_{100} (without carbon feedback) (*25*): CH_4 = 30, CO = 2.65, N_2O = 265, VOC = 4.5.

By "upstream GHG emissions', we mean all collective GHG emissions from exploration, well drilling and development, production and extraction, surface processing, and transport to the refinery gate (well-to-refinery).

1.2.2. GHG mitigation case studies

Here, the four mitigation case studies presented in Fig. S26 (section 2.5) are explained in detail.

1.2.2.1. No Routine Flaring World

In "No Routine Flare World – Moderate" and "No Routine Flare World – Extreme" case studies (scenarios), all global oilfields flaring-oil-ratios (FORs) are limited to 65 and 20 scf gas flared/bbl oil produced, respectively. This is the 25%ile and 5%ile of all studied global oilfields FORs, respectively. Oilfields that already flare less than 65 and 20 scf/bbl (original cases) remain unchanged in "No Routine Flaring World" case studies.

1.2.2.2. Minimal Fugitives & Venting World

The Norwegian oil and gas industry is a successful example in management of gas flaring, and fugitives and venting. In this case study, we take Norway 2015 fugitives and venting reported data from 37 (out of 76 in total) Norwegian oilfields (*26*) as a target emission intensity for oilfield operations with minimum fugitives and venting emissions. Norwegian fields report GHG intensities from flaring and venting of: 0.19 gCO_2eq./MJ (unweighted mean); 0.08 gCO_2eq./MJ (median); and 0.19 gCO_2eq./MJ (volume-weighted mean).

As fugitive emissions from incomplete combustion during flaring are treated separately in OPGEE, here we only focus on fugitives and venting from other extraction and surface processing facilities (e.g. compressors, pipelines, dehydrator unit, etc.; see OPGEE user guide for more details (*12*)).

In the OPGEE base case estimate of global oilfields (8,966 studied fields), the volume-weighted average fugitives and venting emissions are ~2.2 g CO_2eq./MJ. In "Minimal Fugitives & Venting World" case study, all oilfields fugitives and venting emissions are set to 0.2 g CO_2eq./MJ to approximate the 2015 volume-weighted mean from Norway oilfields.

The fourth scenario presented in Fig. S26 is a combination of the "Minimal Fugitives & Venting World" and "No Routine Flare World – Extreme".

It should be pointed out that the above case studies are hypothetical and the feasibility of complying the mentioned flaring and fugitive/venting emissions standards should be investigated in separate work. Also, additional process equipment, activity, etc. may be needed in order to conform to the above standards. These factors and the GHG emissions associated with them are not included in this analysis.

1.2.3. Crude transportation

Crude trading patterns are volatile and generally not reported in public literature. Thus, the effect of oil transportation on the fields overall upstream GHG intensities is modeled consistently by using identical OPGEE defaults for crude oil transportation of all studied oilfields (ocean tanker: 8,000 miles; ocean tanker size: 250,000 tons; pipeline: 1,000 miles). It should be noted that crude transportation GHG emissions contribution in the total field CI is often minimal.

Having access to country level crude oil and oil products trade flows information would assist in order to better understand the upstream CI variability comparing to variabilities in different steps downstream of oil extraction.

1.2.4. Flaring

Flaring contributes to CI through both the CO_2 emissions during combustion of produced gas and methane released due to incomplete combustion. Flare efficiency changes with flare exit velocities and diameters, cross wind speed, and gas composition (*27–29*). For example, flare efficiencies in Alberta were estimated to range from 55% to ≥99%, with a median value of 95%, adjusted for wind speed distributions (*27*). Thus, OPGEE assumes 95% flaring efficiency for this study.

The flare-oil-ratio (FOR, scf/bbl) is defined as volume of gas flared (in scf) over volume of crude oil produced (bbl).

For the studied fields from the top 10 countries with the highest upstream associated gas flaring observed from space via satellite (*30*) – Russia, Iraq, Iran, US, Venezuela, Algeria, Nigeria, Mexico, Angola, and Kazakhstan – it is assumed that no infrastructure is available to collect and process the produced associated gas and therefore, gas export is set to ~0 scf from oilfields (see OPGEE user guide (*12*)).

Gas venting as a substitute for flaring is assumed zero throughout the study. This is because there is no accessible public or commercial venting data and currently no readily available method to measure venting using satellite technology. It should be noted however that flaring/venting is a result of a lack of gas infrastructure and therefore, oilfields of countries with low flaring are most likely in geographic proximity to markets (which makes the development of a gas infrastructure economic) or their existing gas pipeline network is widely spread, and it does not necessarily mean that they are venting instead of flaring.

1.2.5. Oilfields

This study is limited to global oilfields. There is no single clear distinction between oil and natural gas hydrocarbon fields and references are inconsistent in this regard (*31–33*). Here, we include the fields with gas-oil-ratio (GOR, scf natural gas produced/bbl crude oil produced) of <10,000 scf/bbl as oilfields. Global fields with GOR >10,000 scf/bbl are considered gas fields and excluded from our analysis. Note that these excluded fields represent less than 2% of global oil production.

1.3. Co-product accounting approaches

Two main methods exist for addressing the energy use and emissions of oilfields when co-products are also generated (i.e. electricity, NGLs, NG, upgraded process gas, diesel, residual fuel, and petroleum coke). The methods are (*12*, *34*):

1. Co-product displacement: in this approach, an alternative production method for the co-produced product is assessed and the resulting emissions and energy expenditures/gains are credited to the main product as if the co-product directly displaces product generated elsewhere.
2. Allocation: emissions are divided between products and co-products proportionally to a measure of output (often energy, mass, or monetary value).

Both methods are applied in this study. Since most of the available datasets (e.g. the U.S. Argonne National Laboratory's GREET model) uses co-product displacement method to deal with co-products, this method is used by default in the main manuscript. The CI curve resulting using the allocation method instead is presented in SI section 2.1.

1.4. Input data

1.4.1. Data source and availability

OPGEE accepts over 50 parameters to be entered as input data (see Fig. S1) for each modeled field. The OPGEE large-scale analysis tool is used to analyze all fields, and no parameters are changed for oilfields on detailed process modeling sheets. Year 2015 is chosen as the reference year for gathering all input data. 2015 was the latest year with complete data during analysis. Data for the studied fields were gathered through:

1. Government reports: these data are only available for particular regions and only for some of OPGEE input parameters. The year 2015 oil and gas government data from Norway (*26*, *35*), Canada (*36–39*), Denmark (*40*), UK (*41*), Nigeria[1] (*42*), and US (California (*43*), Alaska (*44*), and shale oils (*45*)) are utilized for our study. These data are summarized in the supplementary information (SI) Input Data Excel sheet.
2. Public literature: extensive data mining from public statistics and scientific or technical papers (e.g. Society of Petroleum Engineers Journal) (*46*) is performed. A total of nearly

[1] Some of the Nigerian oil and gas data are reported in a somewhat cursory way. It is recommended to perform cross-check verification within the same report to ensure using right numbers.

800 sources are utilized to construct estimates for the studied fields (see Table S17). The obtained public data can be found in the SI Input Data Excel sheet.

3. Proprietary/Commercial data: lastly, some data from commercial sources (e.g. O&G J 2015 survey (*47*) and Wood Mackenzie oilfield datasets (*48*)) are used as backup to fill missing information (these commercial data are unable to be shared in public domain). Commercial data were utilized for few parameters (production method, field depth, field age, volumetric production, API gravity, and GOR) for some studied fields.

In some cases, data are digitized from literature plots (*49*) which may introduce minor inaccuracies due to pixel-based interpolation. These errors are likely to be small in comparison to other errors introduced by use of modeling defaults in some cases. In cases where high temporal resolution (i.e., monthly) data are reported, all data are converted to yearly averages.

1.4.2. Data processing

As shown in Fig. S2, the data are processed and aggregated via *R* program and stored in *MySQL* database management system (both are open source programs). For each parameter of each field, government data are used if available. Otherwise, an average of public and commercial data (if available) is calculated and inserted. OPGEE defaults are utilized when no data is available for a parameter. See the next section for more details.

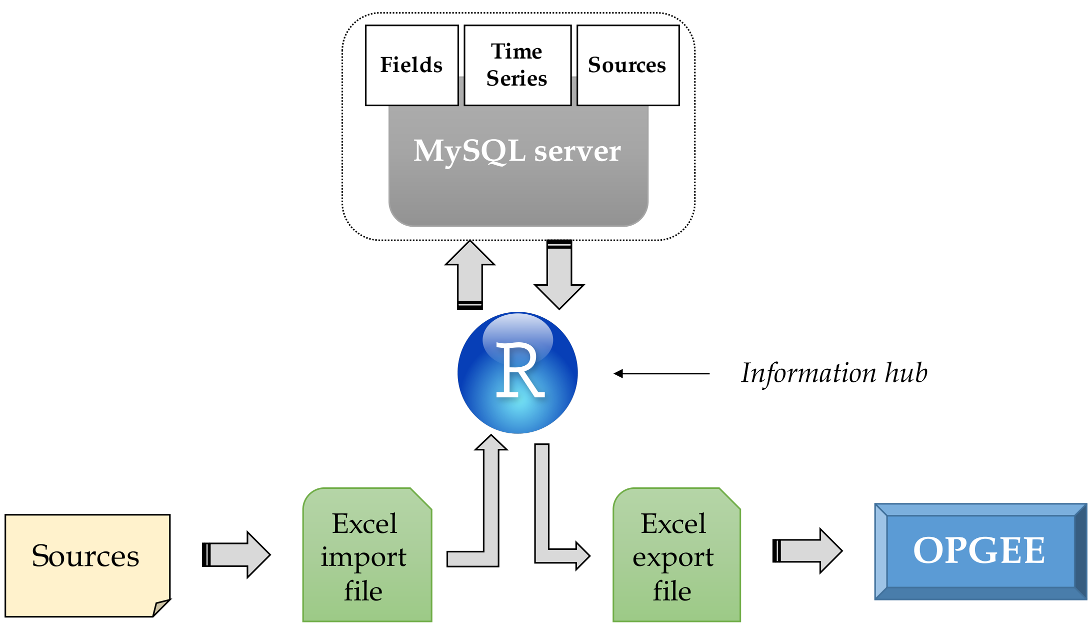

Fig. S2. Data processing flow structure. *R* is used for data processing, programming and aggregation, *MySQL* is used for data storage, and OPGEE is utilized as the LCA simulator.

The way to handle multiple sources of data for the same parameter depends on the nature of each parameter. For example, for the parameters that regularly increase over time (e.g. number of producing wells, number of injection wells), if possible, the most recent data close to the reference year (2015) is used. For the more time independent parameters (e.g. API, well diameter), an arithmetic average is calculated and used. For variables like GOR and WOR that vary over time, a volume-weighted-average based on the reported oil production (bbl/d) data is used.

1.4.3. OPGEE defaults

When input data are not available, OPGEE supplies defaults based on statistical analysis of petroleum engineering literature and commercial sources (e.g. O&GJ (*47*)). For example, the gas-oil-ratio (GOR, scf gas produced/bbl oil produced) and water-oil-ratio (WOR, bbl water produced/bbl oil produced) affect the energy cost of oil production and processing. When these parameters are not reported, OPGEE uses the API gravity and field age to estimate GOR and WOR, respectively, based on statistical analysis of historical data from other global oilfields (*1*, *15*). Such defaults allow OPGEE to generate estimates of emissions in fields without complete data. Below we explain some defaults of the key parameters. See OPGEE user guide & technical documentation for more details (*12*).

1.4.3.1. Field age

Field age data were collected from 8,434 global oilfields. The histogram of field production start year is shown in Fig. S3. The mean date of discovery in the dataset was 1988. However, many of these fields are likely small fields that do not supply large quantities of oil to the global export markets. It is known that giant oilfields are somewhat older on average than the general field population. Fig. S4 shows the corresponding histogram if we only include fields with over 100,000 bbl/d production (109 fields in total). These fields produced cumulative ~32 million bbl/d crude oil in the year 2015 (~40% of global production). These giant fields have a count distribution and production-weighted average age distribution that are somewhat older than the complete set of global fields. See Table S1 for a summary of fields age data. The giant oilfields volume-weighted average is used in this study.

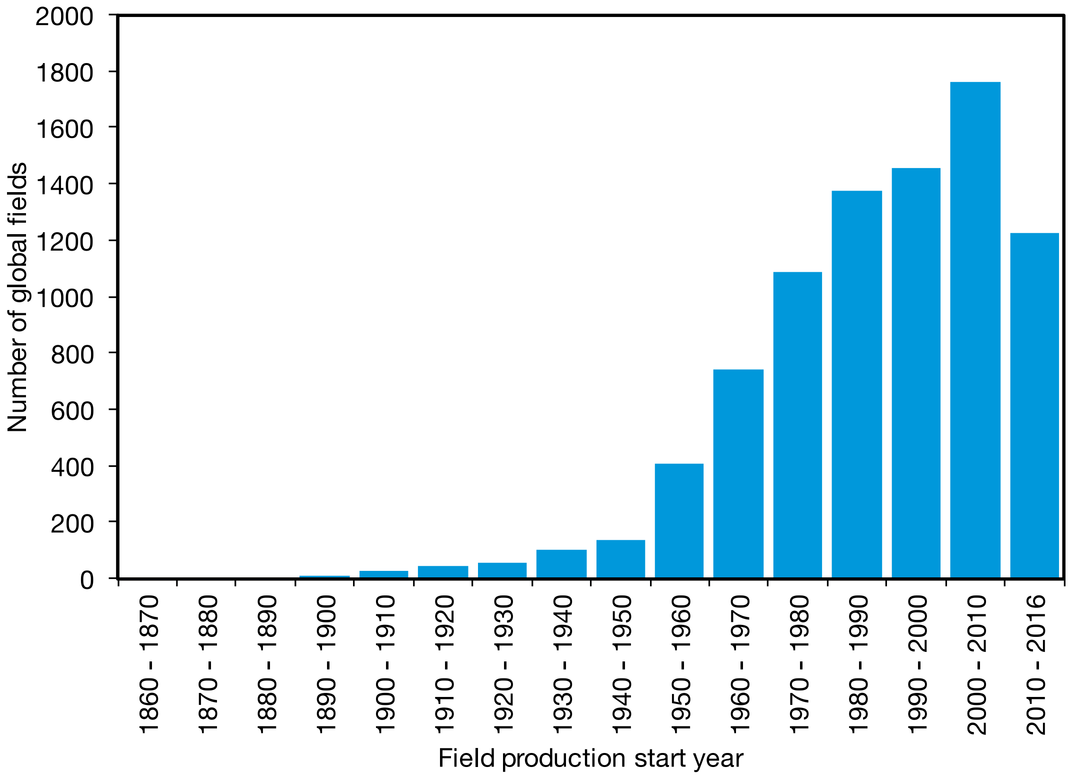

Fig. S3. Distributions of global oilfield ages.

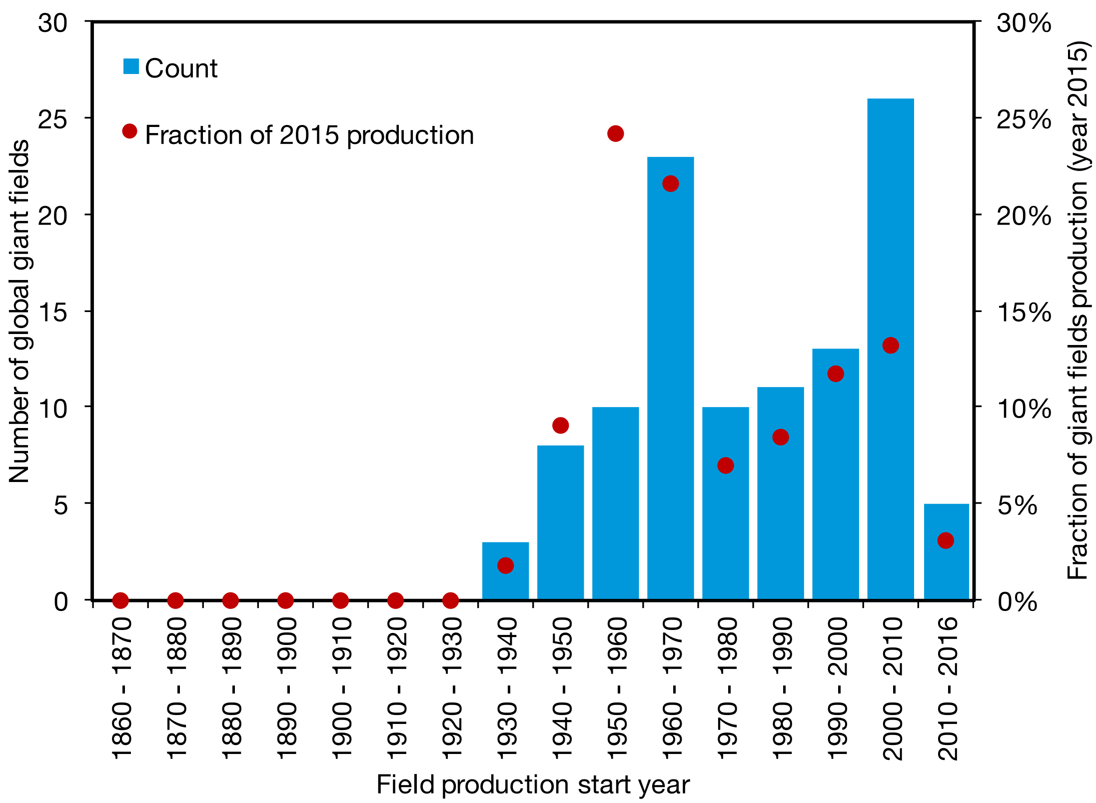

Fig. S4. Distributions of giant oilfield ages.

Table S1. Summary of oilfields age population data.

Reference	Vol. W. Average	Median	Standard Deviation
All global oilfields	1982	1991	21
Giant oilfields	1972	1980	22

1.4.3.2. Field depth

Field depth data were collected for a total of 7344 global oilfields. For fields where a range of depths is presented, the mean of the range is used as a point estimate. The distribution of depths by number of fields per depth range is presented in Fig. S5. The mean depth for these fields is ~7,122 ft (used as deterministic default) and the standard deviation (STDV) is ~3,851 ft. The depth distribution has a longer right (deep) tail than left (shallow) tail, so the mean is somewhat larger than the median (6,654 ft).

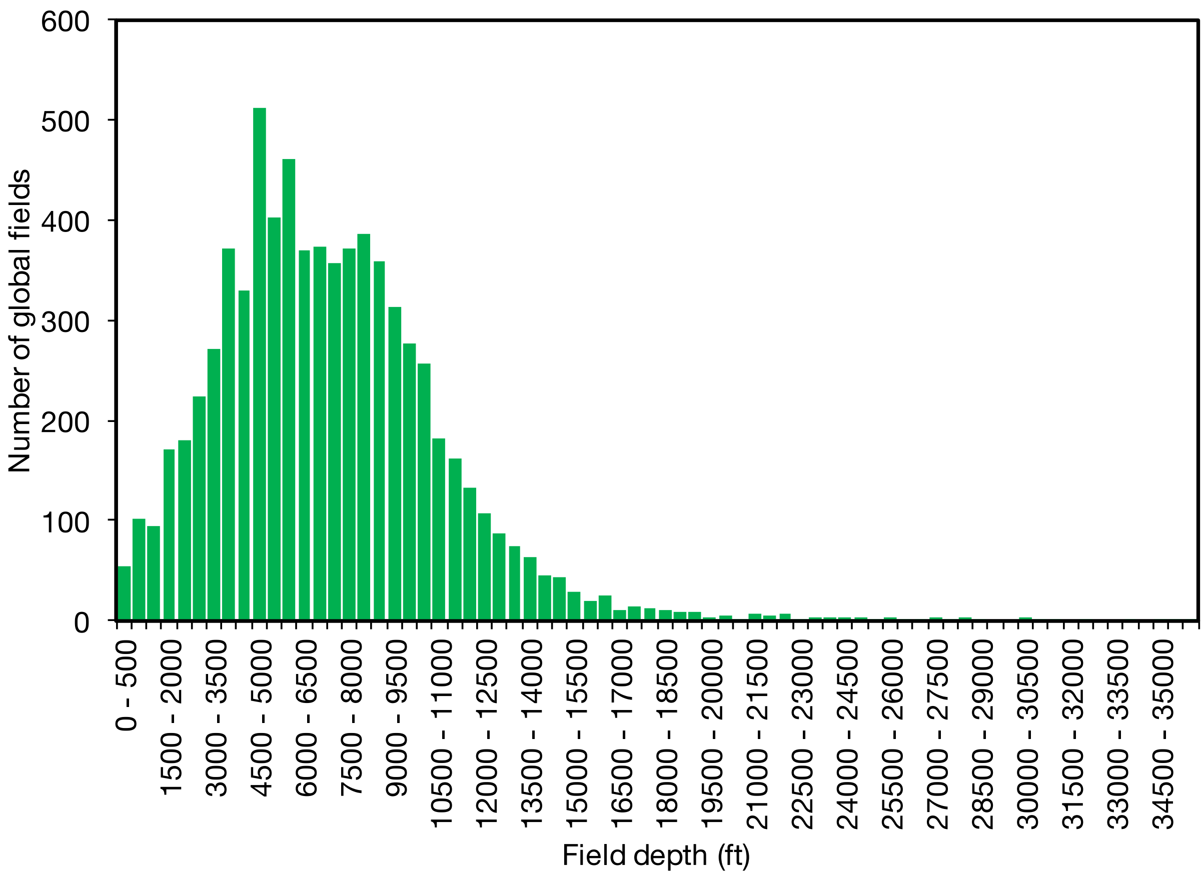

Fig. S5. Distributions of global oilfield depths in bins of 500 ft depth.

1.4.3.3. Oil production volume

In total, 5,070 global oilfields with available oil production data are collected. As shown in Fig. S6, the majority of oilfields produce less than 250 bbl/d, with average and STDV of 2098 and 2445 bbl/d, respectively.

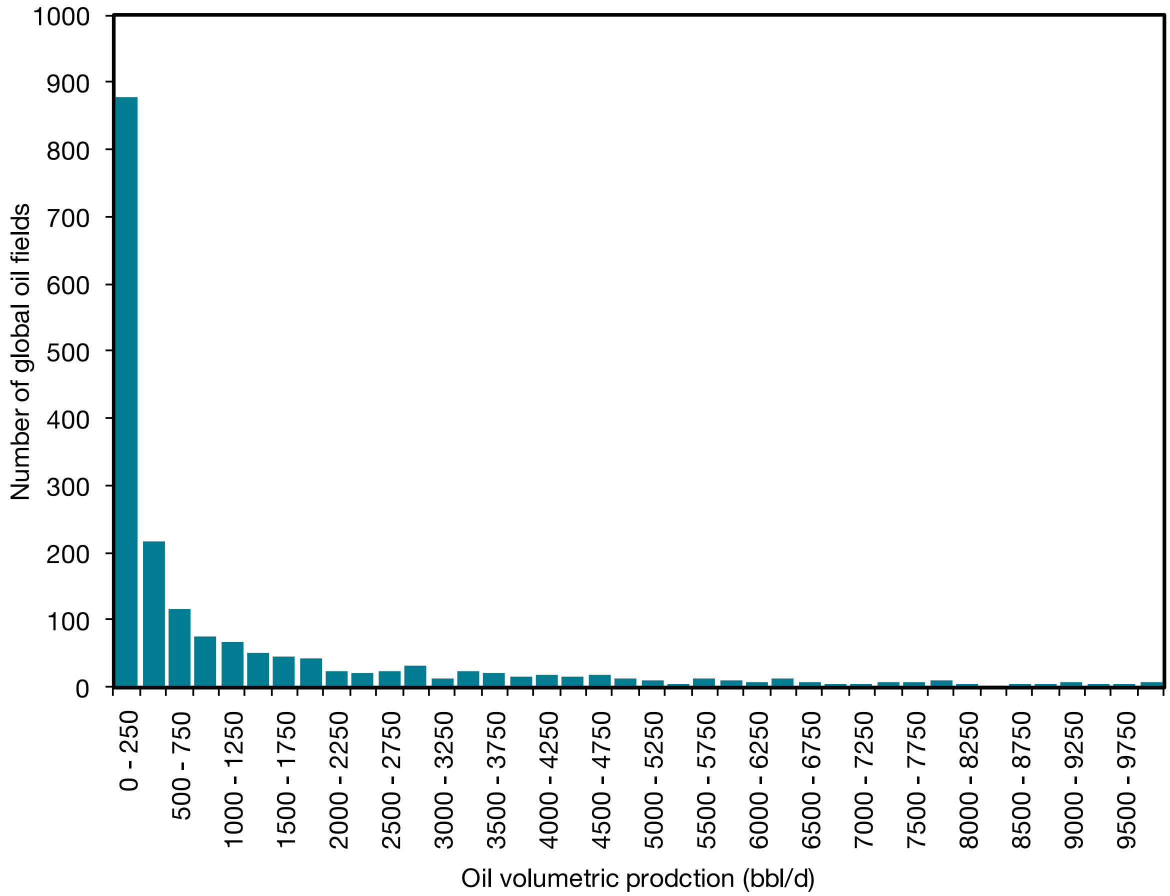

Fig. S6. Distributions of global oilfield daily volumetric oil production in bins of 250 bbl/d production.

1.4.3.4. Number of producing wells

Country-level oil production data and number of producing wells from a total of 106 oil producing countries were collected. The distribution of per-well productivities for all countries is shown in Fig. S7. A majority of oil producing countries produced less than 500 bbl/well-d. Weighting these well productivities by country-level share of global production, we see a very similar distribution. Because of the large number of countries producing less than 500 bbl/welld, we plot the distribution for countries under 500 bbl/well-d (see Fig. S8). For the 61 countries with per-well productivity less than 500 bbl/well-d, the most common productivity by number of countries was the bin of 0-25 bbl/well-d. However, when weighted by total production, the most common productivity bin is 75-100 bbl/well-d. An average productivity of 87.5 bbl/well-d is assumed as default well productivity in OPGEE.

It is commonly known that the higher the field productivity index (PI, bbl/psi-d), the lower the number of producing wells and injectors. Based on the available data on the number of producing wells vs. the productivity index, the default number of producing wells is limited to 200 if the PI is higher than 6 bbl/psi-d.

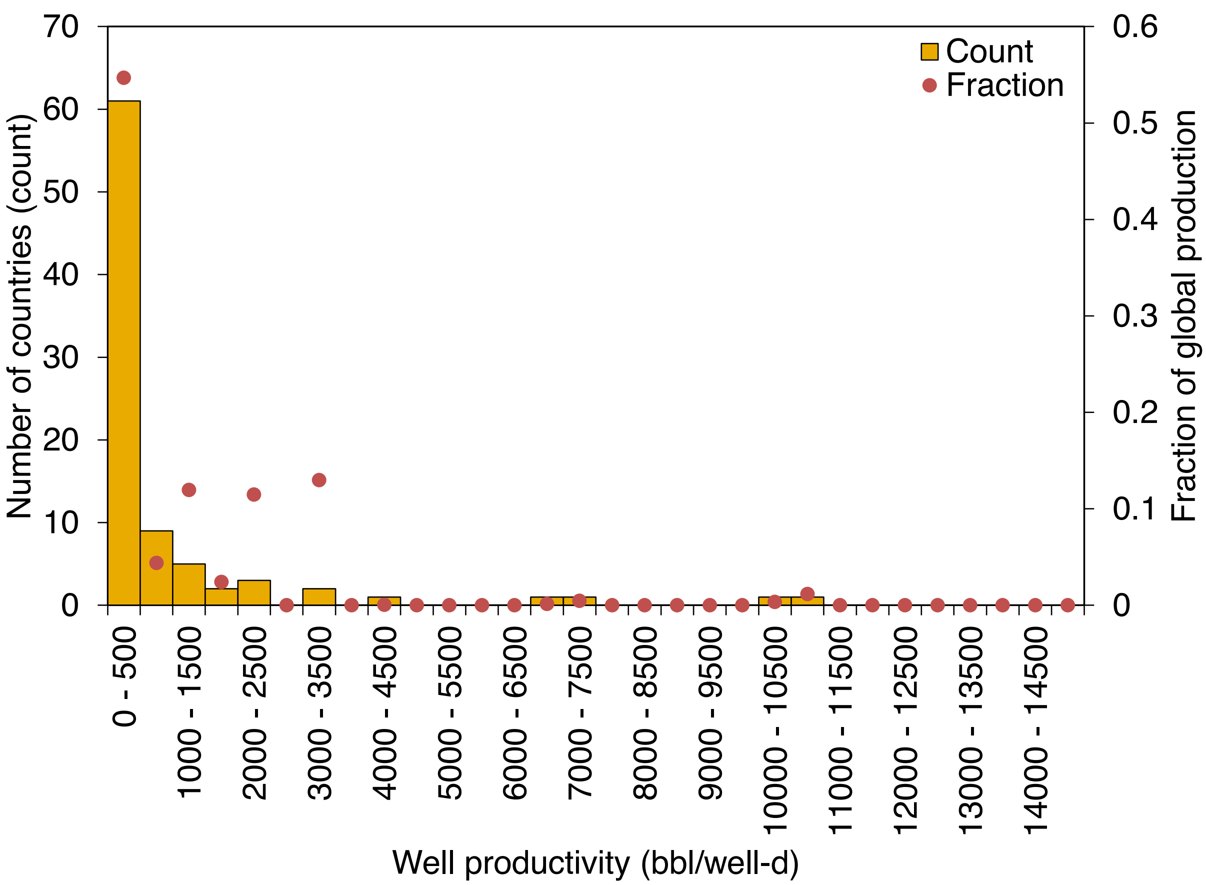

Fig. S7. Distributions of oilfield per-well productivity (bbl oil/well-d) for bins of 500 bbl/d, counted by numbers of countries (bar) and by fraction of production (dot) N = 106 countries.

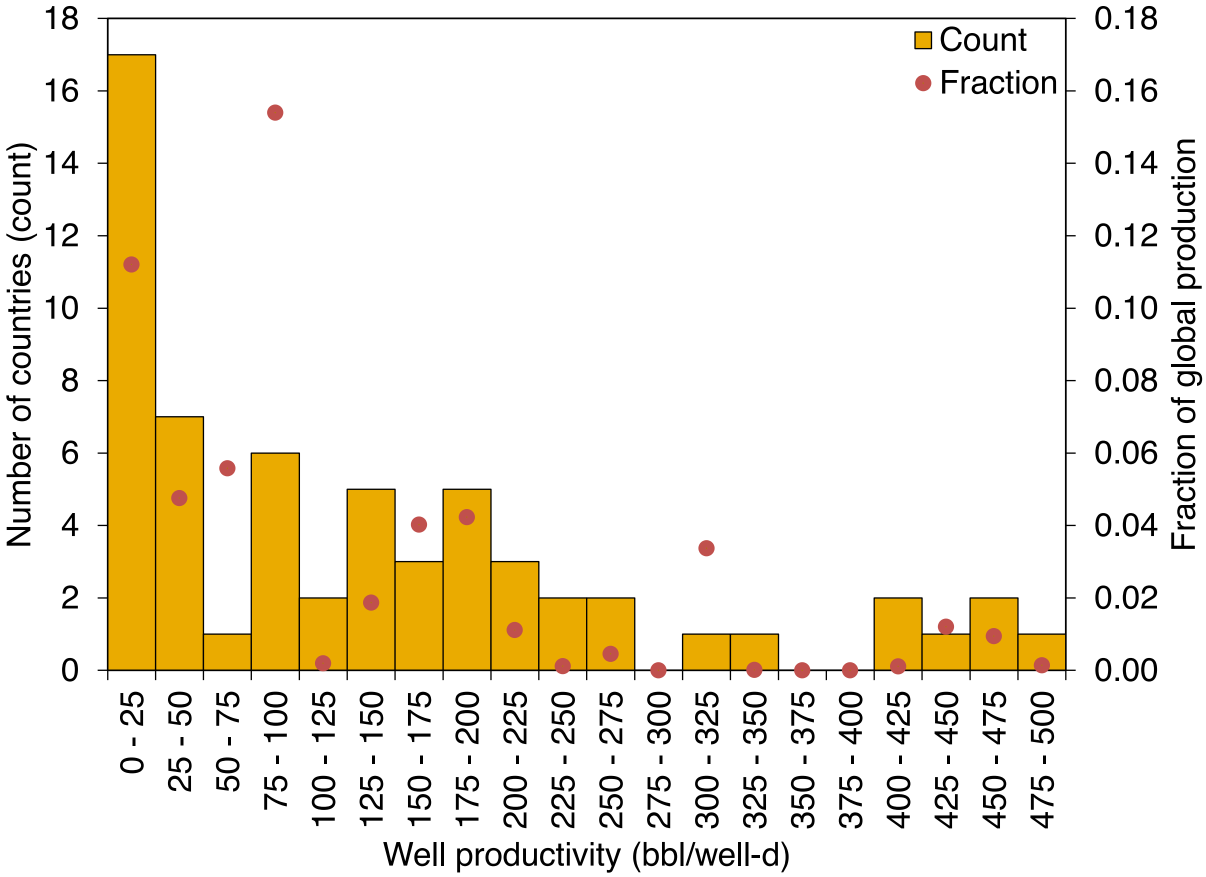

Fig. S8. Distributions of oilfield per-well productivity (bbl oil/well-d) for all countries with per-well productivities lower than 500 bbl/well-d, counted by numbers of countries (bar) and by fraction of production (dot) N = 61 countries.

1.4.3.5. Number of injector wells

The default number of injector wells is a smart default based on the number of producing wells. To model this relationship, data from California, Alaska, and a variety of offshore fields from Canada, Nigeria, Norway and U.K. (206 fields in total) were collected. Per-well productivity across these fields ranges from less than 10 bbl/d to over 10,000 bbl/d. A strong relationship is seen between the productivity of producing wells and the number of injection wells required. Highly productive wells require a significantly larger number of injectors. Fig. S9 shows the relationship between the per-well productivity of a field and the ratio of injectors to producers. Fig. S10 also shows the ratio of injectors to producers' histogram that is not normally distributed. From these data, a relationship was generated for the mean and median ratio for each logarithmic bin of production well productivity (see Table S2). Median values for each bin are used to define the smart default for the number of injector wells.

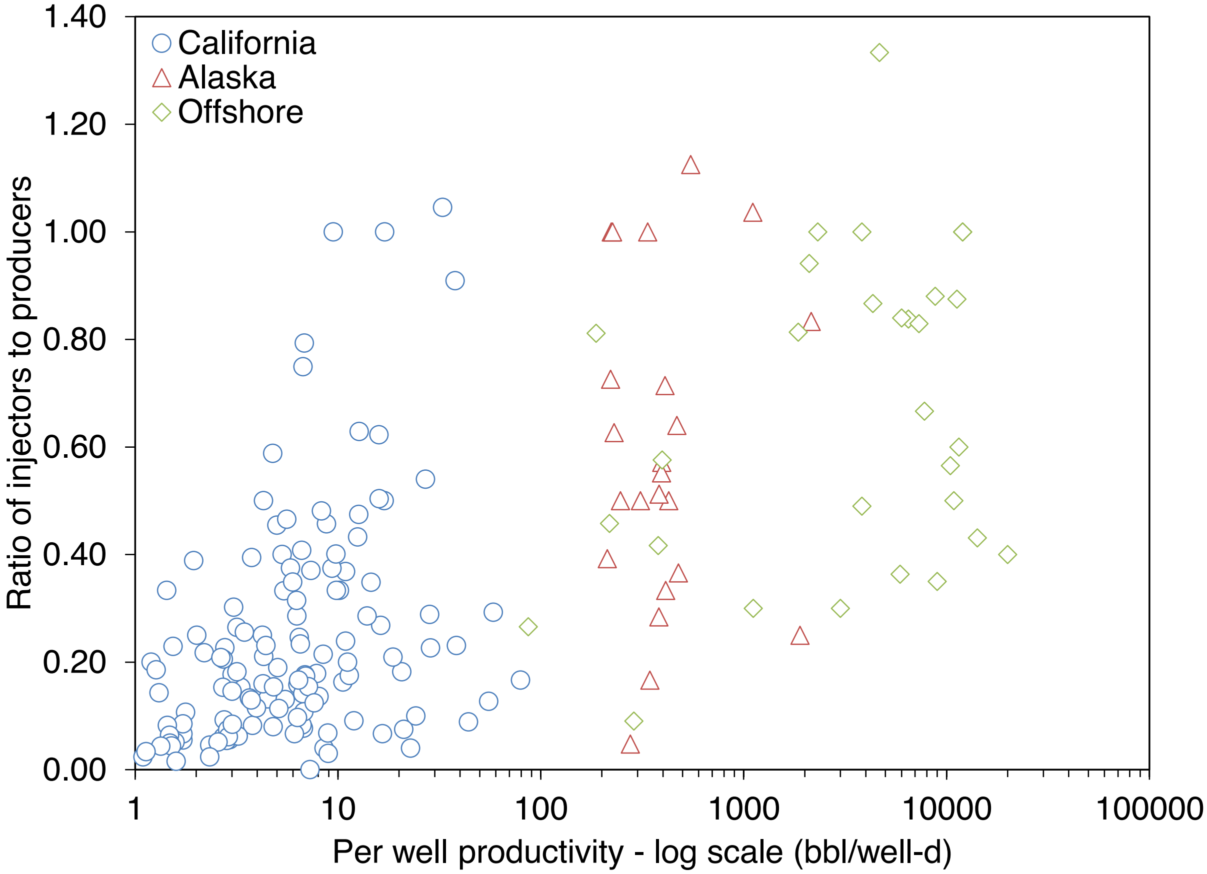

Fig. S9. Ratio of producers to injectors as a function of per-well productivity of 206 fields.

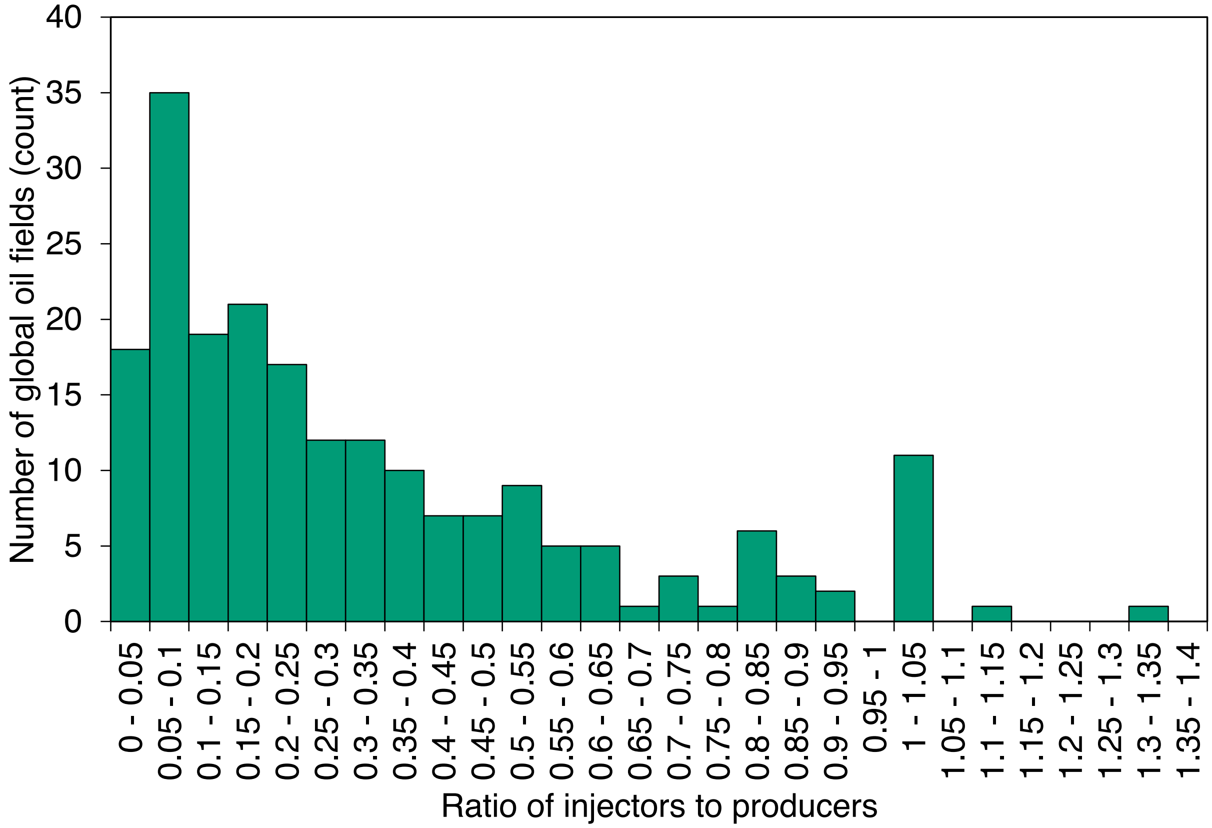

Fig. S10. Distribution of the ratio of injectors to producers of 206 global oilfields.

Table S2. Mean and median injector to producer ratios.

Production well productivity	Mean	Median	STDEV
0-10 bbl/d	0.1957	0.143	0.167
10-100 bbl/d	0.338	0.267	0.259
100-1000 bbl/d	0.556	0.512	0.281
> 1000 bbl/d	0.715	0.829	0.287

1.4.3.6. Well diameter

It is uncommon for a production tubing diameter to be over 5 inch (some highly productive wells in Middle East region excepted). Therefore, a triangularly distributed default well diameter with 1 to 5 inch range is defined in OPGEE. The OPGEE default diameter is 2.78 inches.

1.4.3.7. Productivity index

Oilfields productivity index (PI) is an important OPGEE input parameter, as field PI directly affects the productivity of wells and is therefore a sensitive investment and strategic datapoint. However, PI data are rarely reported in the literature. Based on our few available data

(20 data points), a mean of 17 and STDV of 18 are set as PI default inputs of the simulator. PI is bounded to be positive in all cases.

1.4.3.8. Reservoir pressure

The reservoir pressure is calculated based on a multiplication of a coefficient $\alpha(t)$ (a function of reservoir age, t) to the normal reservoir pressure, the pressure in the reservoir fluids necessary to sustain a column of water to the surface (*50*).

$$P_{res} = \alpha(t) \,.\, D_{res}/2.31 \quad \text{(S1)}$$

where D_{res} is the reservoir depth (ft). In order to find a relationship for $\alpha(t)$, $2.31*P_{res}/D_{res}$ of several offshore and onshore global fields are plotted as a function of field age. Minimizing the square of residuals, different functions (i.e. exponential, logarithmic, polynomial, and power) are examined to find the best fit:

$$\alpha(t) = 4.9 * 10^{-8} t^2 + 0.95 \quad \text{(S2)}$$

1.4.3.9. Reservoir temperature

Reservoir temperature is also a direct function of the reservoir depth and is found to increase by 1°F for about 60 ft in many reservoirs. Reservoir temperature can be estimated base on the following expression:

$$T_{res} = T_a + \text{Thermal gradient} \,.\, D_{res}/100\text{°F} \quad \text{(S3)}$$

where T_{res} and T_a are reservoir and ambient temperatures, respectively. A geothermal gradient of 1.8°F per 100 ft is assumed (*51*).

1.4.3.10. API gravity

The API gravity of 7,223 global oilfields have been obtained. The histogram shown in Fig. S11 reveals that the majority of global fields lie within 35-40 °API with an average of 32.8 °API and a STDV of ~8.4 °API.

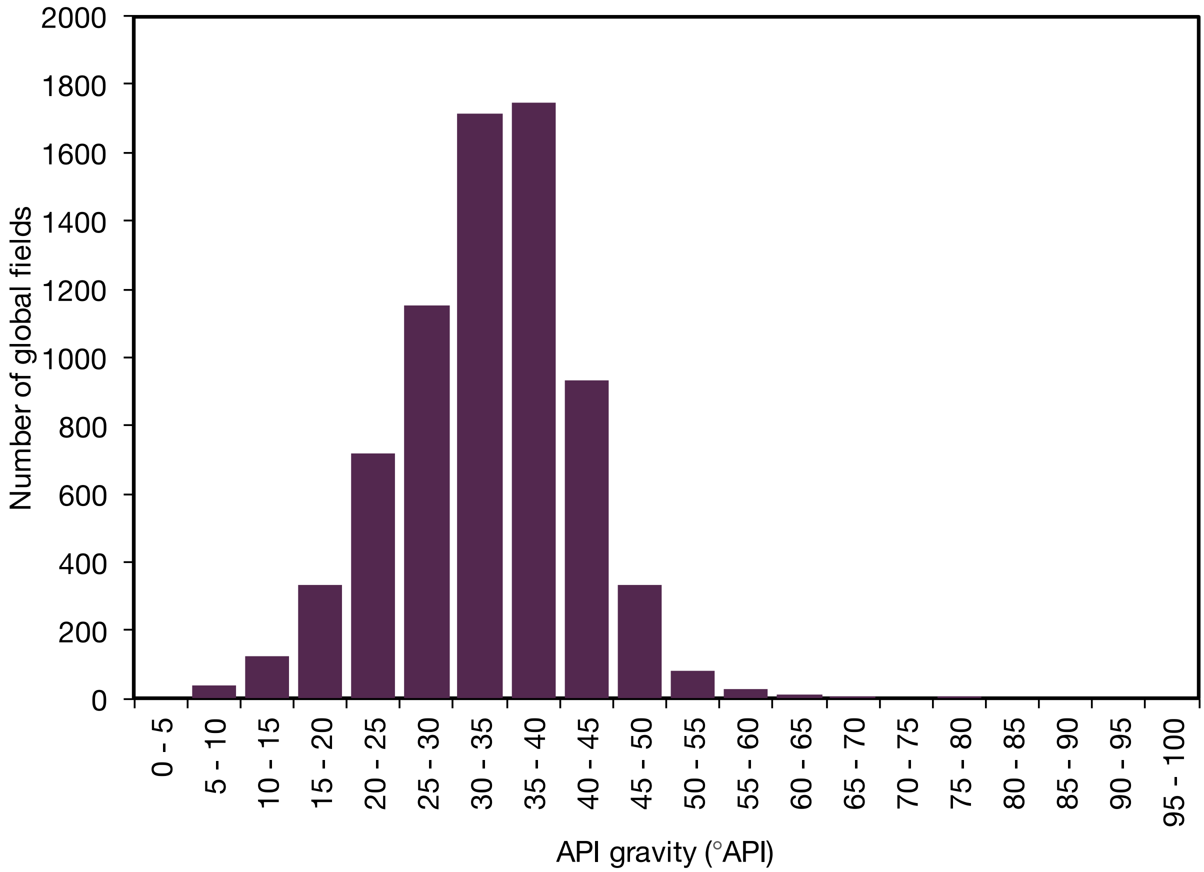

Fig. S11. The API gravity distribution of 7,223 global oilfields for bins of 5 °API.

1.4.3.11. Gas composition

The default gas composition for associated gas from oil production is derived from reported gas composition data from 135 California oilfields (*24*). Species concentration distributions for major gas species is shown in Fig. S12. In order to remove outliers, all compositions with methane concentration less than 50% were removed from the dataset (17 data points removed out of 135). The resulting mean compositions were rounded and used in OPGEE for default gas composition.

Although gas composition is a tertiary parameter (see Input Data Excel file, data scoring sheet) in terms of influence on the CI, it is recommended to develop a default based on global dataset for future analysis.

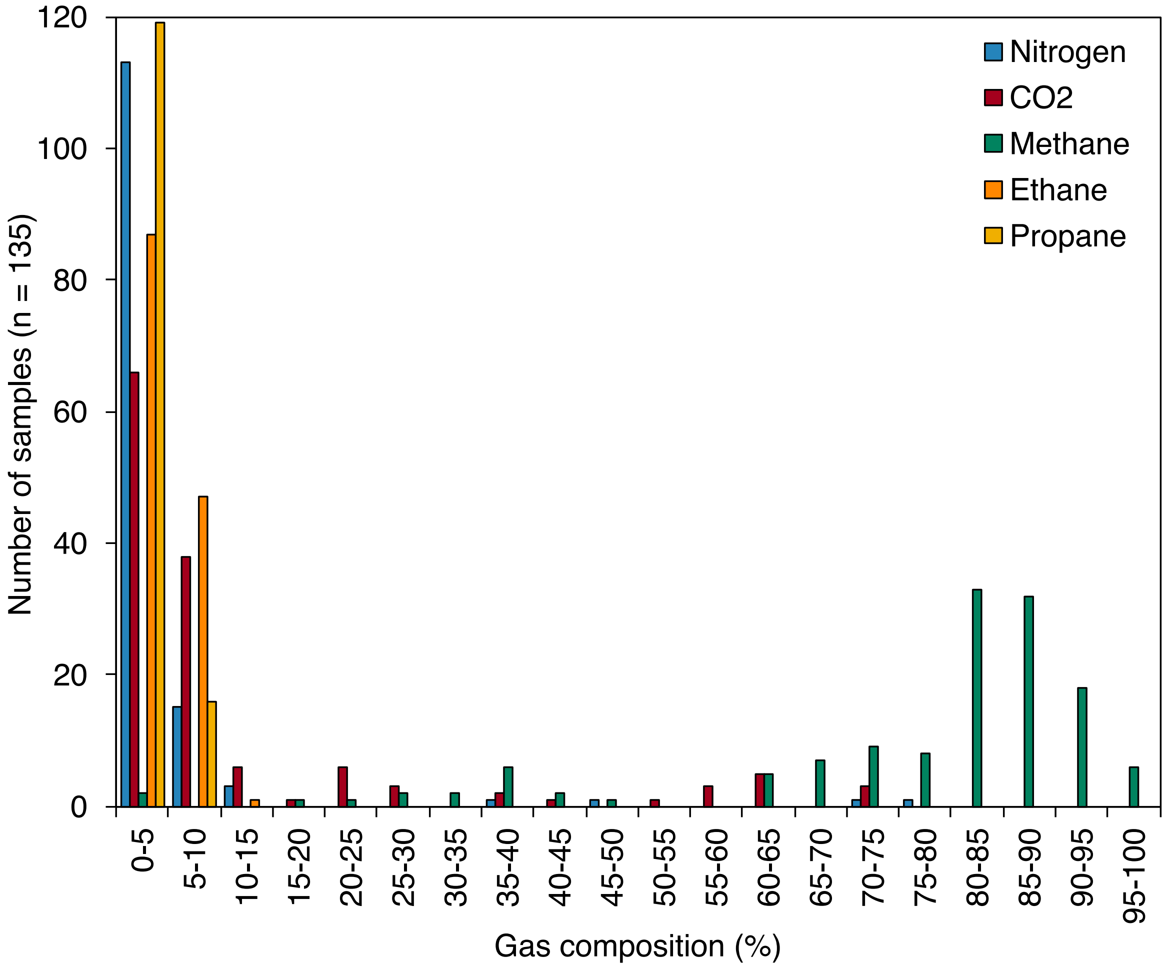

Fig. S12. Distributions of major gas species across 135 samples from California associated gas producers.

1.4.3.12. Gas-oil-ratio

The gas-oil ratio (GOR) varies over the life of the field. The amount of gas able to be evolved from crude oil depends on its API gravity, the gas gravity, and the temperature and pressure of the crude oil (*52*). As the reservoir pressure drops, increasing amounts of gas evolve from the liquid hydrocarbons (beginning at the bubble point pressure if the oil is initially undersaturated) (*52*). This tends to result in increasing producing GOR over time. Also, lighter crude oils tend to have a higher GOR.

Because of this complexity, a static single value for GOR is not desirable. However, all data required to use empirical correlations for GOR is not likely to be available for all crude oils modeled. From primary data we obtained GOR data of 3161 global oilfields. Crude oils are binned by API gravity into heavy (≤20 °API), medium (>20, ≤30 °API), and light crude (>30

°API). The associated gas GOR was compiled for 2015. The distributions, mean, and median values for each crude bin were generated. See Fig. S13 for plot of distributions and Table S3 for listing of mean and median GORs by bin. The median GORs are used to assign a smart default for each bin.

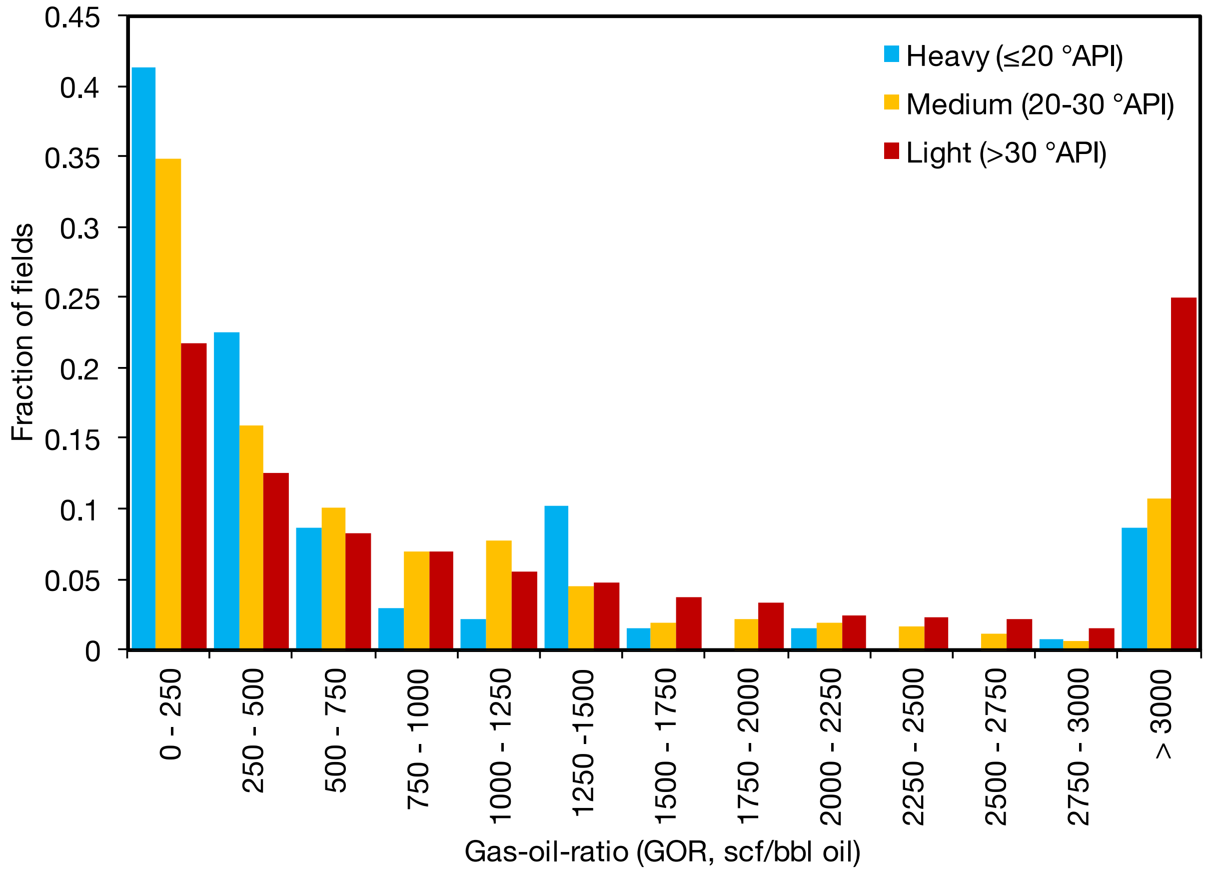

Fig. S13. Distributions of global GORs, binned by crude density.

Table S3. GOR values by crude oil API gravity bin.

Crude bin	Numb. Fields [#]	Gravity range [°API]	Average gravity [°API]	Mean GOR [scf/bbl]	Median GOR [scf/bbl]	STDV GOR [scf/bbl]
Heavy	149	≤20	16.4	1122.4	333.3	2829.7
Medium	758	>20, ≤30	26.3	1205.3	399.8	2277.9
Light	2254	>30	37.7	2429.3	910.8	3635.9

1.4.3.13. Water-oil-ratio

Some defaults require more flexible ("smart") default specifications. The water-oil-ratio (WOR) is a major parameter in influencing GHG emissions. OPGEE includes a statistical relationship for water production as a function of reservoir age. The default exponential relationship is a moderate case parameterized with a variety of industry data. Nevertheless, this relationship does not work well in predicting WOR for giant fields with very high per well productivity (e.g., Ghawar in Saudi Arabia).

A smart default for the water oil ratio as a function of field age was generated using data from large fields in various world regions. Data on oil and water production were extracted from reports issued by California Division of Oil, Gas and Geothermal Resources (DOGGR) (*53*), Alaska Oil and Gas Conservation Commission (AOGCC) (*44*), Alberta Energy Resources Conservation Board (ERCB) (*36*), Natural Resources Canada (NRC) (*39*), United Kingdom Department of Energy and Climate Change (DECC) (*41*), and the Norwegian Petroleum Directorate (NPD) (*26*, *35*). For the Norwegian fields, water production data were not available prior to the year 2000. For Alberta fields, data were not available prior to 1962. Only data for the first 60 years of production were included. Only California fields contained data beyond 55 years, and therefore we excluded these years to avoid possibly atypical depleted field behavior in California from significantly affecting the least squares fit.

Because the majority of crude oil that is marketed globally originates from larger oilfields, fields that have produced less than 630 million bbl of crude oil were excluded. Also excluded from the analysis were fields that produce heavy crude using steam injection.

Additionally, a small number of fields were excluded because of apparent data anomalies or unusual events that may have affected oil or water production. The Redwater field in Alberta was excluded for data anomalies. This field has highly unusual water production data that can only be plausibly attributed to data entry error. Also, the Piper field in the U.K. was excluded because oil production was halted for several years. In total, data from 30 giant oilfields (12 onshore and 18 offshore) were included in the analysis.

The default WOR is represented by an exponential function:

$$WOR(t) = a_{WOR}\exp[b_{WOR}(t - t_0)] - a_{WOR} \qquad \text{(S4)}$$

where a_{WOR} = fitting constant for the initial WOR in time = t_0 [bbl water/bbl oil]; b_{WOR} = exponential growth rate [1/y]; t_0 = initial year of production (or year of discovery if year of first production unavailable) [y]; and t = year being modeled (independent variable) [y]. Note that the pre-exponential a_{WOR} is subtracted to force WOR to start at 0 when $t = t_0$. This model was fit to the collected data using a nonlinear least-squares fit from multiple starting points to ensure robustness. The results of fitting this model to the smart default fit values, compared to oilfields from a variety of world regions, is show in Fig. S14. The resulting fit gives a_{WOR} = 4.020 and b_{WOR} = 0.024. Fig. S15 histogram also shows that the 30 global oilfields WORs are distributed lognormally, with the majority of the data between 0-0.25 bbl water/bbl oil.

The WOR data STDV is also plotted vs. field age, as shown in Fig. S16. A power function with R^2≈91% is fitted to the data in order to be used as smart default WOR STDV:

$$WOR\ STDV(t) = c_{WOR}(t - t_0)^{d_{WOR}} \tag{S5}$$

Here c_{WOR}=0.012 and d_{WOR}=1.662.

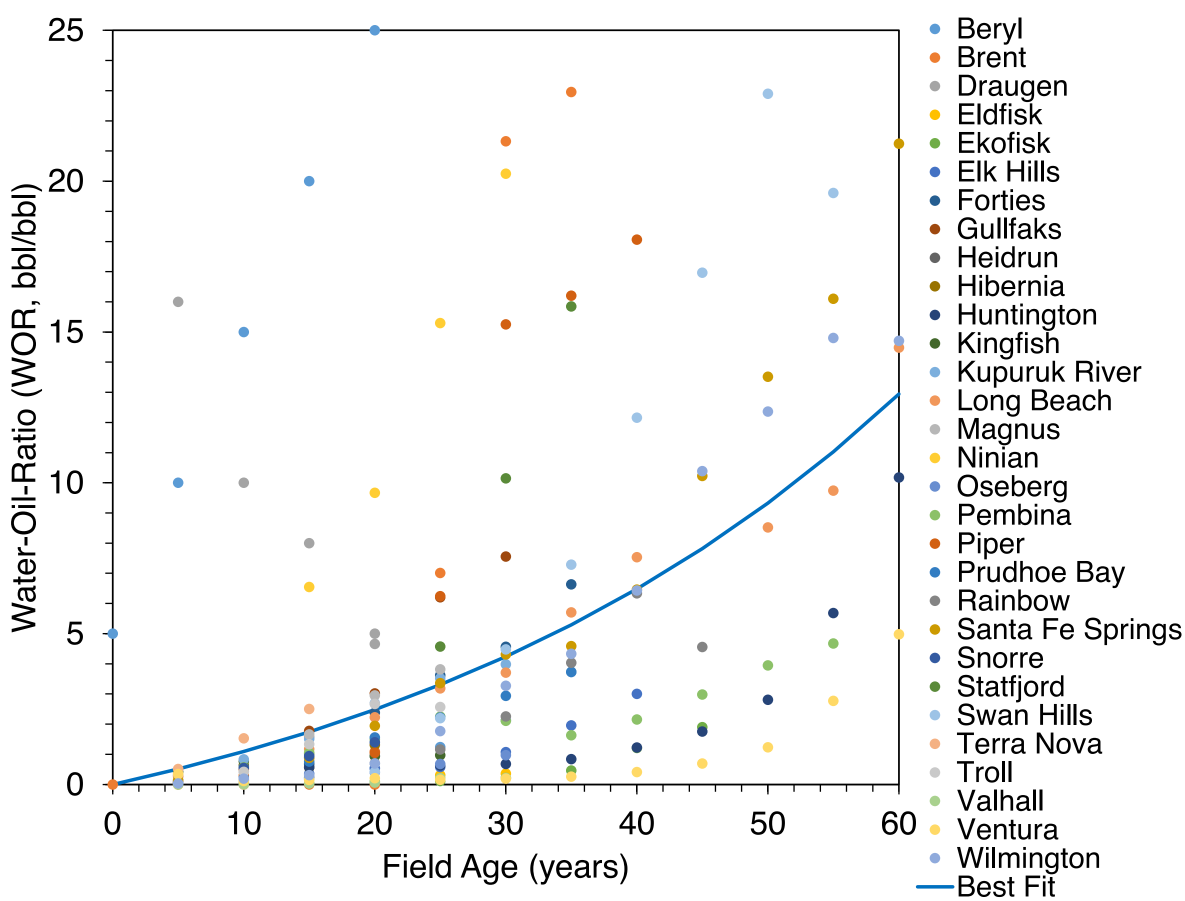

Fig. S14. Exponential WOR model fit with smart default parameters. The best fit to data gives a_{WOR} = 4.020 and b_{WOR} = 0.024.

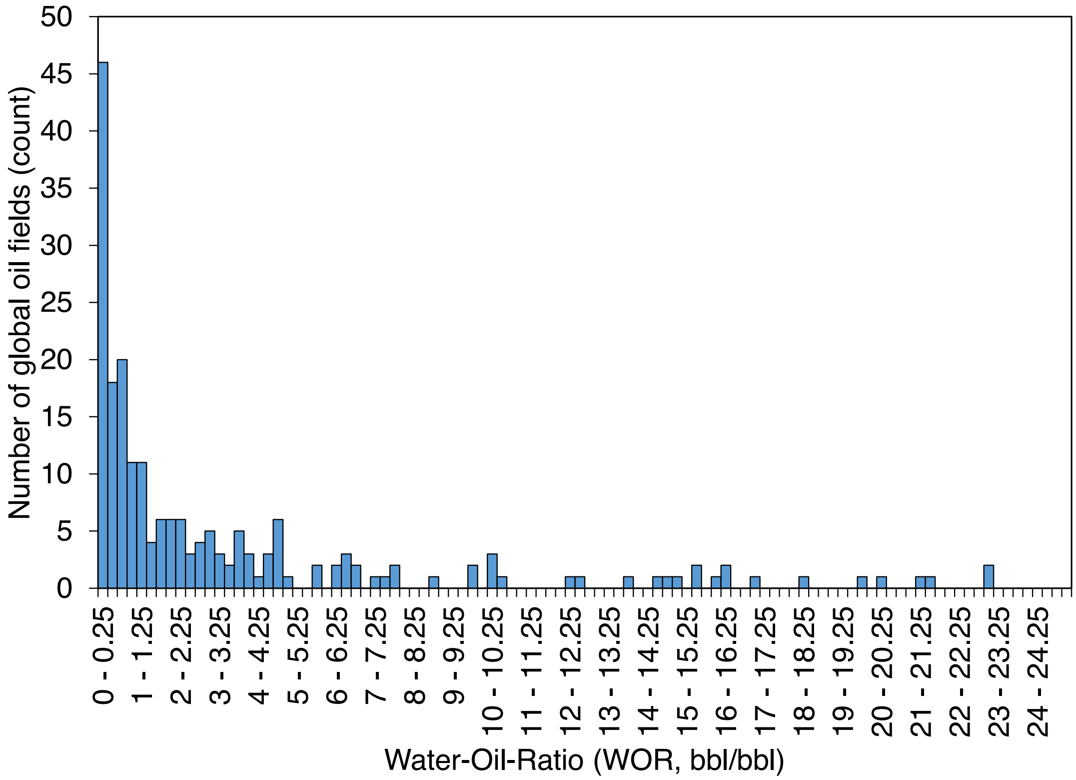

Fig. S15. The WOR distribution of 30 global oilfields for bins of 0.25 bbl water/bbl oil.

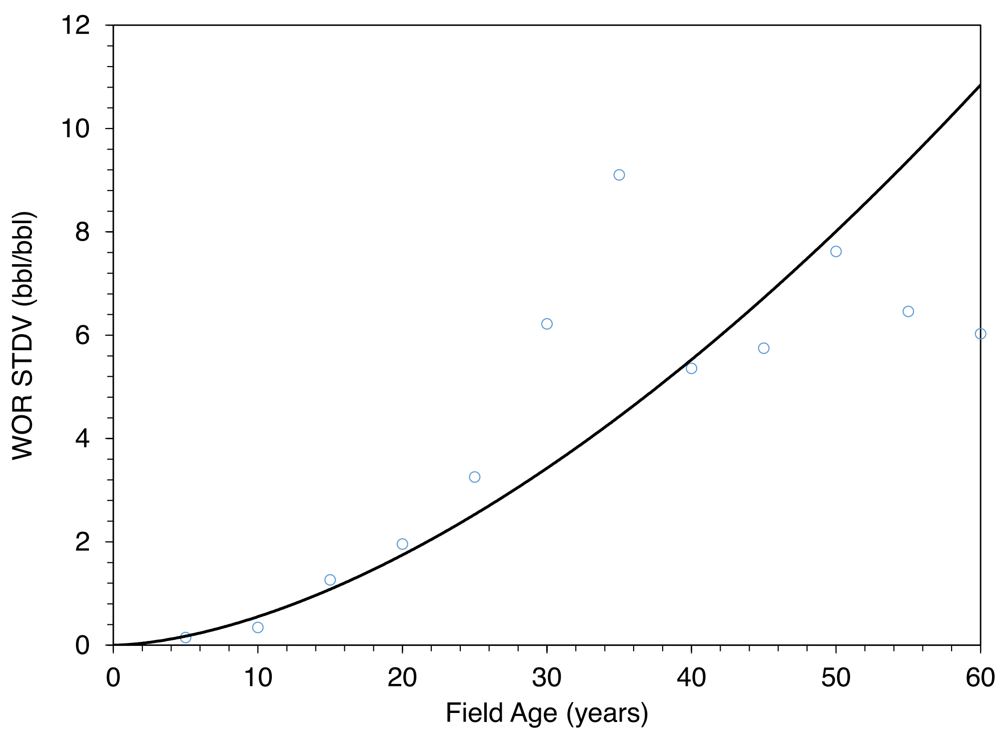

Fig. S16. Power WOR STDV model fit with smart default parameters.

1.4.3.14. Water flooding volume

The volume of water injected in a water flooding project is meant to maintain reservoir pressure. As a default value, OPGEE assumes that the surface volume is replaced, such that the total oil produced plus the water produced is reinjected, or the injection per bbl = 1 + WOR. This estimate is well matched with the experimental data in oil and gas industry (also aligns with personal communications with oil companies).

1.4.3.15. Flood gas injection ratio

The ratio of the volume of flood gas injected [scf] to the volume of oil produced [bbl] is defined as flood gas injection ratio. The volume of the oil is measured after bulk processing has removed the associated gas. The default flood gas injection ratio depends on the choice of flood gas. If natural gas, air, or O_2 is selected as the flood gas, then the default ratio is calculated as follows:

$$F_R = 1.5GOR \quad [\frac{\text{scf gas}}{\text{bbl oil}}] \tag{S6}$$

where F_R = flood gas injection ratio [scf/bbl] and GOR is the gas-oil-ratio [scf/bbl].

If N_2 is selected as the flood gas, then the default flood gas injection ratio is 1,200 scf/bbl. This is based on the immiscible nitrogen flood operation at the Cantarell field in Mexico to maintain reservoir pressure. See the user guide (*12*) for more details.

If CO_2 is selected as the flood gas, then the default flood gas injection ratio is 10,000 scf/bbl. As with all injection ratios, this ratio changes over the life cycle of the flood project. It can also vary based on the specific reservoir engineering strategies selected by the operator. See the user guide (*12*) for more details.

The OPGEE default flood gas injection ratios are presented only as representative values that provide an order-of-magnitude estimate. Actual field data should be obtained when possible.

1.4.3.16. Proportion of injected CO_2 that is newly acquired

As an example value, the OPGEE default for the proportion of CO_2 that is newly acquired (not previously injected) is 41%. This figure is from Malone et al. (*54*) discussion of an offshore CO_2 flood project at Weeks Island, Louisiana over a 9-year period (based on dates in the original reference by Johnston and Perry (*55*)). As with the flood gas injection ratio, actual data should be used if possible.

1.4.3.17. Steam-oil-ratio

Because the steam-oil-ratio (SOR) is a key parameter driving GHG emissions from thermal oil production operations, we examine default values for SOR in more detail. SOR data are collected for California and Alberta thermal oil recovery operations (*36*, *53*).

For California operations, incremental SOR is calculated using volumes of steam injected and reported incremental production due to steam injection. 'Total' SOR is also calculated using total production by field and total steam injection.

For Alberta operations, data on bitumen produced and steam injected were collected for 24 thermal recovery projects (SAGD and CSS). No data were available on incremental rather than total production, and it is not clear what incremental production figures would represent bitumen operations where non-enhanced production would be very small. Production volumes are binned by SOR for both regions and reported in Fig. S17. Averages for SOR are presented in Table S4. The default SOR in OPGEE V2.0 is 3.5 bbl cold water equivalent (CWE) per bbl oil.

1.4.3.18. Gas flaring

Gas flaring volumes were taken from field-level government reporting and public literature where possible, and from country-level National Oceanic and Atmospheric Administration (NOAA) satellite observations (*30*) in case where no data are reported. It should be pointed out that there are different sources of uncertainty associated with the satellite flaring data. For example, is the NOAA satellite detector well-calibrated? How can we be sure that low flaring is not an indication of venting? These important questions need to be addressed in the future research, and are out of the scope of the presented work.

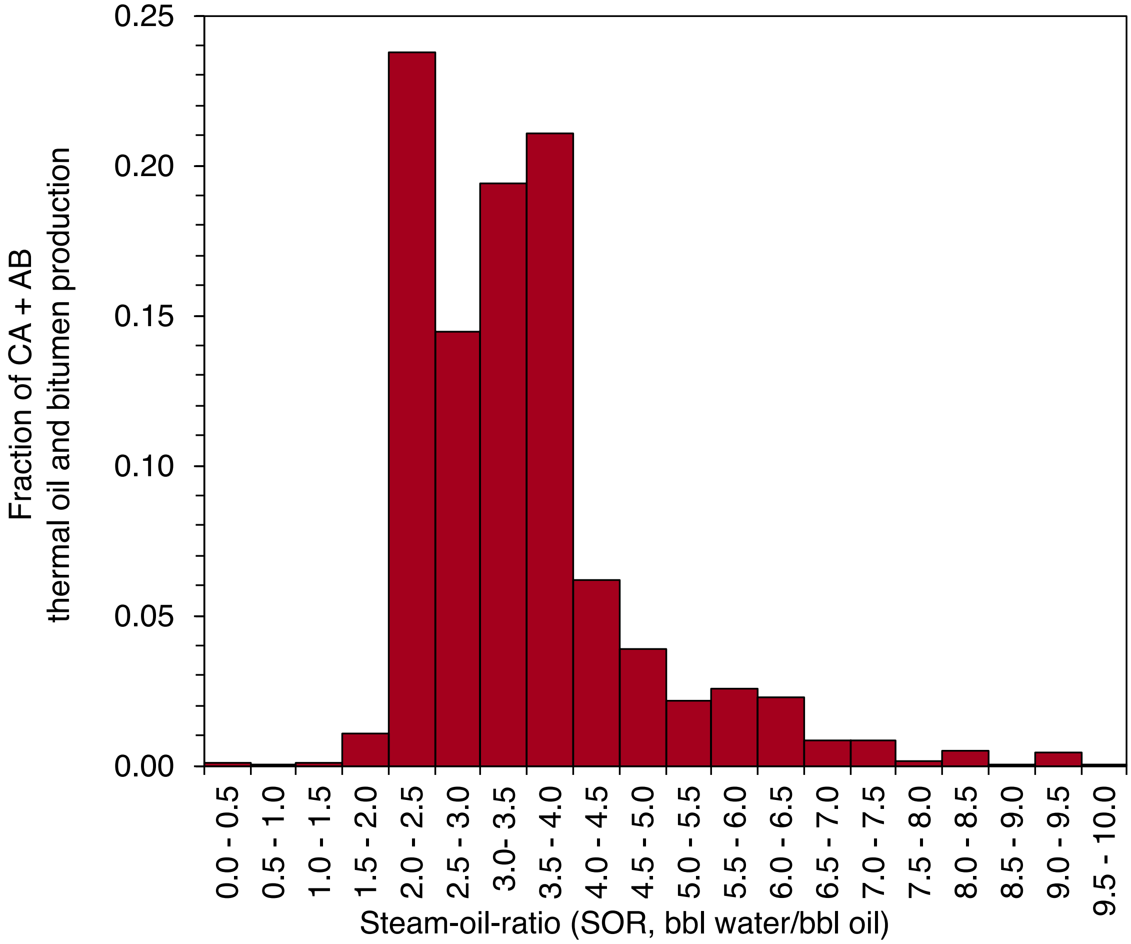

Fig. S17. Distribution of SOR values for California and Alberta thermal EOR projects (steam flood, cyclic steam stimulation, steam-assisted gravity drainage).

Table S4. Indicators of SOR distributions for California and Alberta thermal EOR production.

	Mean - SOR_t	Mean - SOR_i
California - 2014	3.32	4.29
California - 2015	3.41	Unk.
Alberta - 2014	3.58	NA
Alberta - 2015	3.32	NA

1.4.4. Data coverage

Table S5 summarizes data coverage in this study. With combination of government reported data, public literature, and commercial data sources as input data to OPGEE (see section 1.4.1), we estimate emissions in the year 2015 from 8,966 on-stream oilfields in 90 countries. These oilfields have combined oil production of ~78.9 million barrels per day, capturing ~98% of 2015 global crude oil and condensate production (*56*). Government and public literature data are collected and used for 1,009 global fields, heavily weighted towards large oilfields and thus accounting for about 64.3% of 2015 global crude oil production. Commercial data are utilized for the rest of analysis (capturing mostly small fields).

Table S5. Data coverage summary of this study.

Source of data	Number of fields	Cumulative production, MMbpd	2015 Global coverage %
Government and public data	1,009	51.7	64.3
Commercial data	7,957	27.2	33.9
Total	**8,966**	**78.9**	**98.2**

1.4.5. Treatment of Canadian oil production in global oil CI assessment

Here, we explain the methods used to align outputs from Canada's modeled oilfields to Canada's National Energy Board (NEB) statistics for 2015 (*38*):

1. NEB production output by category for 2015, in kbbl per day were:
    - Conventional: 806
    - SCO: 976
    - Bitumen: 1,405
    - Other heavy oil (listed as "conv."): 430
    - Condensate and C5+: 222
2. Statistics for oil sands operations from the following locations
    - In situ from ST-53 report, Alberta Energy Regulator (AER) (*57*)
    - Mining and upgrading from ST-39 report, AER (*58*)
3. Where possible, additional data gathered for in situ operations, as ST-53 does not include operational data other than SOR. Additional data gathering from AER "In Situ Performance Presentations". To reduce data gathering requirements from In Situ Performance Presentations (ISPP) (*59*), a complete list of in situ projects from ST-53 was filtered to remove projects that produce less than 500 m^3/month. This leaves the following breakdown (Table S6):

Table S6. Breakdown of included and excluded projects for data gathering.

Included for data gathering	Excluded from data gathering
Algar	Algar Lake
Christina Lake	BlackGold
Christina Lake	Blackrod
Cold Lake	Blackrod
Firebag	Cadotte HCSS
Foster Creek	Cliffdale Pilot
Great Divide	Dover
Hangingstone	Gemini
Hangingstone	Germain
Jackfish	Harmon Valley Pilot
Joslyn Creek	Harmon Valley South Thermal Pilot
Kirby	Harper
Leismer	Mackay River
Lindbergh	Pelican Lake
Long Lake	Pelican Upper Grand Rapids
Mackay River	Saleski Phase 1
Orion	Sawn Lake
Peace River	Seal CSS
Primrose and Wolf Lake	Surmont Pilot
STP McKay	West Ells
Sunrise	
Surmont	
Tucker Lake	

4. All in situ projects, unless noted below, are assumed to use dilution of 25% vol/vol with condensate diluent composition (final dilbit vol%):
    - Suncor MacKay River (non-upgraded) is assumed blended with SCO to make heavy synthetic.
    - Suncor Firebag (non-upgraded) is assumed blended with SCO to make a heavy synthetic.
5. After matching in situ projects to projects already in database (public and commercial data), the following projects from the "excluded" list in table above are added back in:
    - Algar Lake
    - MacKay river
    - Pelican Lake

- Seal CSS

6. For mining data, ST-39 was processed to generate the following figures:
   - Bitumen production
   - SCO production
   - Bitumen deliveries
   - SCO deliveries
7. For additional mining data, AER and other sources (e.g., oilsands magazine) were consulted for project configuration, upgrader type, and supply and disposition of bitumen by project.
8. The following methods are used for mining projects:
   - Suncor mine is modeled using OPGEE upgrader configuration #1, DC
     i. Suncor mine SCO (331 kbbl/d) and bitumen (113 kbbl/d) outputs are gathered from ST-39.
     ii. Direct bitumen output (113 kbbl/d) blended is assumed sourced from Firebag and MacKay because of higher in situ bitumen quality.
     iii. Remainder of Firebag and MacKay is assumed to be sent to upgrader.
     iv. Upgrader sources remainder of feed to generate 331 kbbl/d SCO from Suncor mine.
   - Syncrude mine is modeled using OPGEE upgrader configuration #3, HC+FC
     i. Syncrude outputs of SCO (249 kbbl/d) is gathered from ST-39
     ii. Syncrude produces no other outputs
   - AOSP (Muskeg/Jackpine/Scotford)
     i. Muskeg and Jackpine bitumen production gathered as bitumen deliveries (335 kbbl/d).
     ii. Net Scotford bitumen deliveries computed as bitumen delivered to Scotford less bitumen delivered by Scotford (231 kbbl/d).
     iii. Jackpine and Muskeg mines are assumed to supply all of Scotford net bitumen deliveries.
     iv. Remainder of Jackpine and Muskeg projects output is assumed to be exported as bitumen, either from Scotford, or directly to a refinery as dilbit (104 kbbl/d).

v. Scotford refinery is modeled using OPGEE upgrading configuration #2, HC.
vi. AOSP mines are assumed to not consume net diluent, as input diluent to Scotford almost exactly matches output diluent from Scotford.

- Horizon mine is modeled using OPGEE upgrader configuration #1 (DC)
- Kearl mine does not upgrade but exports diluted bitumen
  i. Bitumen deliveries (155 kbbl/d) and SCO deliveries (49 kbbl/d) are collected.
  ii. SCO delivery matches SCO receipts, confirming that this SCO is used as a diluent stream. Kearl is assumed to therefore not consume diluent (deliveries of diluent are small, most is used as fuel or "wasted" per ST-39.

9. Because the OPGEE modeled fields from data gathering and commercial data do not add up to NEB volumes, we add to our database an additional conventional, condensate, and heavy oilfield to balance NEB production:
   - "Other conventional" – Generic crude of 30 °API produced via downhole pump and water flooding. Set to balance conventional production from NEB against sum of production from other modeled or commercial data fields with >=20 °API and <45 °API.
   - "Other heavy" – Generic crude of 17.5 °API produced via downhole pump. Set to balance "Heavy conv." production from NEB against sum of production from our other modeled fields with <20 °API.
   - "Other condensate" – Generic crude of 55 °API set to balance our diluent consumption for dilbit sales (computed as above) against NEB condensate production.
10. Final disposition of crude and comparison to NEB is as follows (Table S7):

Table S7. Comparison of this work coverage with NBE.

Crude type	OPGEE vol. [kbbl/d]	NEB vol. [kbbl/d]	Ratio [OPGEE/NEB]	Notes
Conventional	**834**	**836**	**0.998**	**>= 20 °API, < 45 °API**
SCO – Mine	887	-		
SCO – In situ	99	-		
SCO – Total	**986**	**976**	**1.010**	
Bitumen – Mine	259	-		
Bitumen – In situ	1128	-		
Bitumen – Total	**1387**	**1405**	**0.987**	
Other heavy	**428**	**430**	**0.995**	**< 20 °API**
Condensate – Dilbit	168	-		
Condensate – Other	58	-		**>=45 °API**
Condensate – Total	**226**	**222**	**1.018**	
Total crude	**3,861**	**3,860**	**0.998**	

11. Lastly, CO_2 sequestration from Shell Quest project is computed. Net sequestration of 1 million tonnes of CO_2 per year, is converted to grams per day. This amount is subtracted from AOSP upgrader emissions (~2 gCO_2/MJ). The adjusted AOSP intensities are then used in volume-weighted average for the country.
12. Final number of modeled Canadian crudes: 84, including three "generic" crudes to make up volume missing from database. Some projects split into two (i.e., "Firebag – upgraded", "Firebag – Not upgraded")

1.4.6. Data quality scoring

In order to have a better understanding of OPGEE input data quality per field and per country, a systematic data quality scoring is performed using *R* program. Each input parameter (of each field) is scored based on data source type and vintage (see Table S8). Data from government sources receive the highest score. Lower scores are allocated to commercial data as they are not peer-reviewed and accessible for evaluation in public domain. If no data are available for a parameter, OPGEE default is used (see section 1.4.3) and therefore, it receives the lowest score. Since the presented study reference year is 2015, the data are also scored based on their reference publication year. It should be pointed out that here we only focused on technical aspects of data quality scoring. Other factors (e.g. authenticity of government reporting based on international corruption indices) could be explored in future analyses for improve of data quality assessment.

As shown elsewhere (*20*, *60*), some input parameters have higher impact on fields total life-cycle GHG emissions estimate. Thus, the input parameters are classified as primary, secondary, or tertiary based on their importance level (see Table S8). See Input Data Excel file (data scoring sheet) for the list of primary, secondary, and tertiary parameters. The scores are weighted based on their significance and then the total weighted-average score of each field is estimated. See section 2.3 for results.

Table S8. Data quality scoring measures.

Source of data	**Score**
Government	9
Literature (peer-reviewed)	8
Other literature (technical report, presentation)	6
Commercial	5
OPGEE default	3
Publication year	**Score**
< 10 years	8
10-20 years	5
>20 years	3
Contribution significance	**Weight factor**
Primary	2
Secondary	1
Tertiary	0.5

1.5. Input parameters statistical importance analysis

In order to study the significance of input parameters on the output carbon intensities methodologically, predictive statistical models are fit to the CI results (OPGEE outputs). The resulting statistical models allow to predict the results of OPGEE software without the expense of running OPGEE simulations. The independent variables in order to train the models are selected based on prior studies (*20*, *60*) that identified the key OPGEE input parameters which have dominant effects on the CI results uncertainty. The selected nine independent variables (x_1

to x_9) are as follows: FOR, API gravity, SOR, WOR, PI, Field depth, water injection ratio (WIR), GOR, and number of wells. Our sensitivity analysis on the effect of all OPGEE input parameter on the CI predictions out of the trained models also confirms the previous studies (*20*, *60*) and the leading influence of the above parameters on models predictions accuracy. Terms without statistically significant coefficients (e.g. production rate) are removed from the models. The only output (dependent variable) is the carbon intensities.

The dataset (i.e., OPGEE input parameters and CI results for 8,966 global oilfields) is split into a training dataset and a testing dataset. The testing set is a randomly selected subset of ~10% of the dataset (from 877 fields) which is removed from the dataset and held aside (i.e., not used to generate the statistical fit). The training set includes the rest of the dataset, which is ~%90 of data (from 8,089 fields). The training and testing sets are drawn independently for each predictive equation.

Ten models are developed in total (see Table S9) using polynomial quadratic regression. Linear regression resulted in unsatisfactory coefficient of determination (R^2) and therefore is not considered further. The reference model (model #1) is trained by incorporating all nine independent variables. In order to rank the importance of the independent variables, one of them is excluded from the training process for each of the other nine models (model #2 – #10; see Table S9). The quadratic equation includes all linear terms, interaction terms, and square terms. The quadratic models are of the general form of:

$$CI = \alpha_0 + \sum_{i=1}^{9} \alpha_{1i} x_i + \sum_{i=1}^{9} \sum_{j=i+1}^{9} \alpha_{2ij} \left(x_i \times x_j \right) + \sum_{i=1}^{9} \alpha_{3i} x_i^2 \qquad \text{(S7)}$$

where the coefficient α_0 is the intercept, α_{1i} are linear coefficients, α_{2ij} are coefficients on interaction terms, and α_{3i} are quadratic coefficients on squared terms. The models coefficients are presented in Results Data Excel file (Importance Analysis sheet).

After the quadratic regression, the fitted model is fed the independent variables from the test dataset and asked to predict the dependent variables from the test dataset. The results from these testing runs are shown in Table S9 and Results Data Excel file (Importance Analysis sheet). Table S9 data reveal that excluding FOR or SOR (models #2 and 3) result in higher drop in the polynomial regression R^2 comparing to the other independent variables. Therefore, flaring and thermal extraction via steam injection for heavy crudes are the key determinants of the output CI (see Fig. 2). Much lower R^2 of model #2 relative to model #3 suggests the significance of FOR relative to SOR.

Table S9. Ten statistical predictive models for importance analysis.

Model #	**Excluded independent variable**	R^2	R^2 **difference relative to the reference model**
1 (reference model)	None	0.807	-
2	FOR	0.246	0.561
3	SOR	0.715	0.092
4	WOR	0.790	0.017
5	Field depth	0.798	0.009
6	WIR	0.800	0.007
7	API	0.803	0.004
8	GOR	0.804	0.003
9	PI	0.805	0.002
10	Number of wells	0.805	0.002

1.6. Cross correlation analysis

In order to assess any potential correlations between OPGEE different key parameters, a cross correlation analysis is performed. Figure S18 shows a cross correlation analysis of the major common input parameters across all global fields. It reveals that for the parameters with appreciable cross correlation coefficient (over 0.4 for WOR vs Age, and WOR vs WIR; and over 0.23 for API vs GOR) we already assigned OPGEE defaults incorporating the relationship between these factors (see above). In order to have regional estimates of missing FORs, it is preferred to use NOAA country-level satellite data (*30*) instead of a general correlation between FOR and GOR. Although no noteworthy correlation between other studied parameters is observed, additional hidden relationships or selection biases might exist.

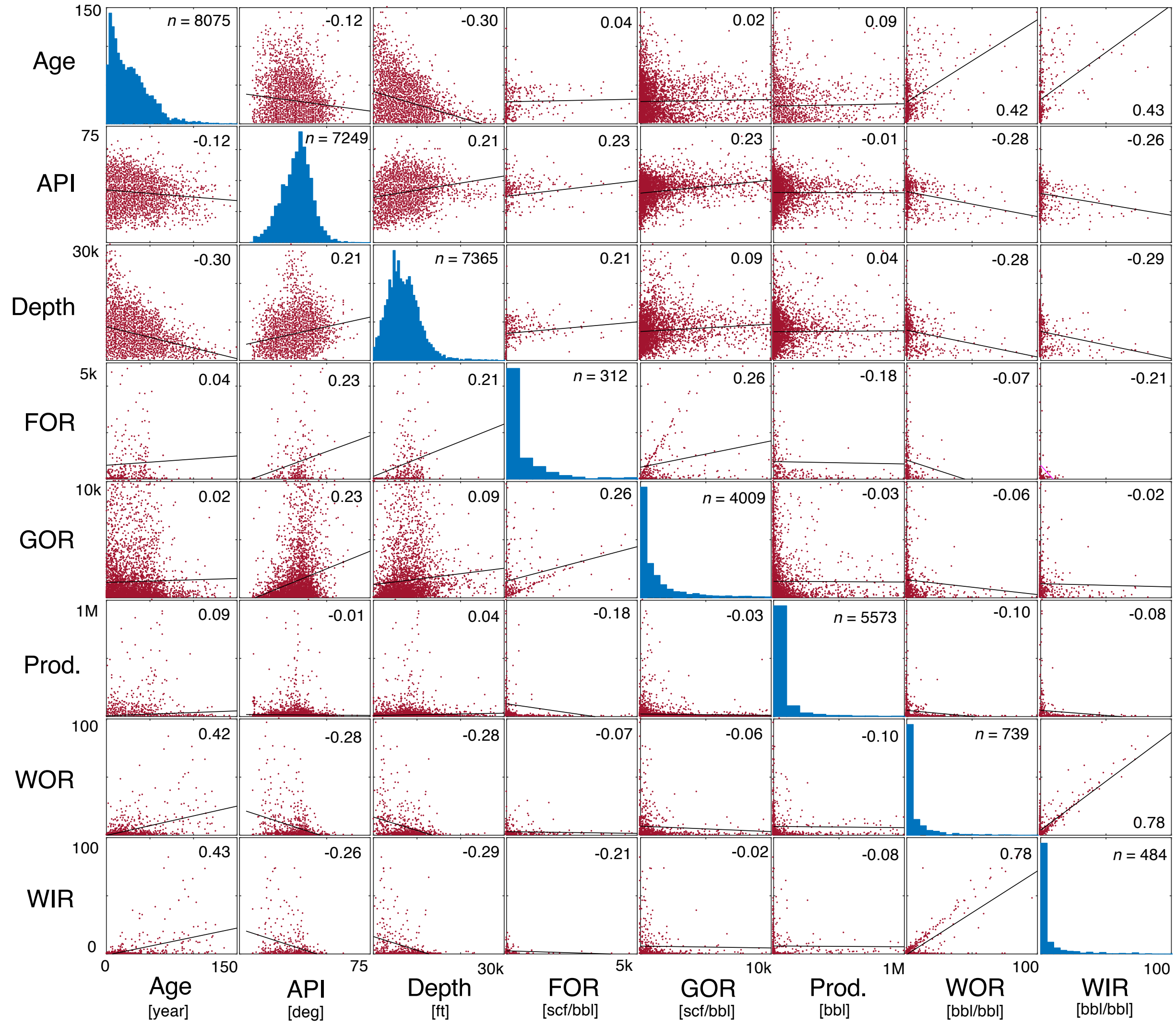

Fig. S18. Cross correlation analysis of OPGEE key input parameters. Constructed using MATLAB statistical toolbox. Term in upper right hand corner is R^2 of correlation between the variable on the x-axis and the variable on the y-axis. Along the diagonal, the distribution of the values of that parameter are given, along with the number of observations in the dataset.

1.7. Probabilistic uncertainty analysis

As mentioned before, OPGEE requires about 50 parameters as input data for each oilfield. If input data are not available for some of these parameters (common due to lack of publicly available data), OPGEE uses defaults (see section 1.4.3) to fill missing information. What if one does not want to use OPGEE defaults? Then what is the uncertainty associated with the missing data?

It has been shown recently that emissions uncertainty depends on the key input parameters, and the use of default values in the place of specific data (*20*, *60*). Therefore, here we only analyze the uncertainty associated with OPGEE missing input parameters. Other uncertainty sources include: unchanging parameters embedded into OPGEE (e.g. downhole pump efficiency, etc.), model structure, and modeling equations used for process units. See the OPGEE user guide & technical documentation for more details on other defaults (*12*).

The uncertainty associated with the CI estimates is computed probabilistically using a Monte Carlo (MC) simulation method. In each Monte Carlo realization, for each field, missing data are replaced not with the OPGEE default value but instead with a value from the underlying distribution or statistical values. A total of 500 Monte Carlo realizations are generated per field. See Table S10 for summary of input parameters and their probabilistic distribution indices used for this analysis. 500 realizations are more than sufficient as convergence analysis shows that after 300 realizations a consistent result distribution is obtained (i.e., more MC simulations no longer strongly affects mean, median or SD of uncertainty realizations). For each Monte Carlo realization, the global oilfields are re-ordered by CI in order to produce Fig. S25.

Note that some of the input parameters in Table S10 are treated deterministically:

- **Parameters 1.7-1.9:** almost all of the global heavy crudes (e.g. Californian fields, Canadian and Venezuelan oil sands) are covered in this work and thus, these production practices are excluded from the probabilistic simulation.
- **Parameter 4.6:** deterministic approach is followed as the majority of the fields use natural gas for EOR.
- **Parameter 4.7.2:** It is known that most of the studied CO_2-EOR fields use natural subsurface CO_2.
- **Parameter 4.7.3:** CO_2 sequestration is not practiced in almost all of the active oilfields in 2015 and therefore is not considered in the Monte Carlo analysis.
- **Parameter 5.4:** path #5 is used for every oilfield with known processing path (except CO_2-EOR fields). As natural gas is considered for EOR and CO_2-EOR is not included for Monte Carlo simulation, option #5 is chosen as the only gas processing path for all probabilistic realizations.
- **Parameter 5.7:** this parameter is known and related to oil sand fields that are well covered in this work. Thus, deterministic approach is followed.

- **Parameter 7.1:** as explained in section 1.2.3, the effect of oil transportation on the fields overall upstream CI is modeled consistently by using identical OPGEE defaults for crude oil transportation of all studied oilfields (ocean tanker: 8,000 miles; pipeline: 1,000 miles). Therefore, only ocean tanker and pipeline are considered for uncertainty analysis.

The error bars presented in Fig. 1 are based on GHG emissions 5 and 95%iles of Monte Carlo simulation. Since many parameter distributions are lognormal in nature (Table S10), the CI error bars in Fig. 1 are skewed high. The error bars in Fig. 1 for different countries are independent but comparable to each other as the same uncertainty analysis methodology is used for each field/country. Larger error bars for a particular country could be originated from 1) missing of more important parameters (e.g. primary variables), 2) missing frequency in different oilfields of the same country, or a combination of both factors.

Prior studies (*20*, *60*) have identified the key OPGEE input parameters that drive the uncertainty associated with the CI results. These parameters are as bellow:

- **Primary parameters:** steam-oil-ratio (SOR), API gravity, water-oil-ratio (WOR), gas-oil-ratio (GOR), and flare-oil-ratio (FOR);
- **Secondary parameters:** field depth, productivity index, number of wells, production rate;
- **Tertiary parameters:** include other remaining parameters.

The above classification is a good guideline to prioritize critical field parameters to be obtained in order to minimize the uncertainty of the CI results.

Given that the need for better data is a key conclusion of this work, the Input Data Excel file (Missing Data sheet) shows which parameters were least well populated and for what percent of global production these parameters are missing. From primary parameters, more effort should primarily be devoted to find FOR and WOR data, whereas for secondary parameters, searching to find additional Productivity Index and Number of producing wells data is of great importance.

Table S10. Summary of input default parameters and their probabilistic distribution measure used in this study.

Input Parameters [unit]	Mean	STDV	Low Range	High Range	Prob. Yes (binary)	Distribution Type
1. Production methods						
1.1 Downhole pump	0	0	0	0	0.95	Binary
1.2 Water reinjection	0	0	0	0	0.25	Binary
1.3 Natural gas reinjection	0	0	0	0	0.95	Binary
1.4 Water flooding	0	0	0	0	0.75	Binary
1.5 Gas lifting	0	0	0	0	0.05	Binary
1.6 Gas flooding	0	0	0	0	0.05	Binary
1.7 Steam flooding	0	0	0	0	0.00	Binary
1.8 Oil sands mine	0	0	0	0	0.00	Binary
1.9 Oil sands mine	0	0	0	0	0.00	Binary
2. Field properties						
2.1 Field age (t) [y]	35	22	2	82	-	Lognormal
2.2 Field depth (D_{res}) [ft]	7,122	3,851	59	35,837	-	Lognormal
2.3 Oil production volume (OPV) [bbl/d]	2,098	2,445	10	10,000	-	Lognormal
2.4 Number of producing wells [#]	OPV/87.5	2,445/87.5	1	114	-	Lognormal
2.5 Number of water injecting wells [#]	Table S2	Table S2	1	95	-	Lognormal
2.6 Well diameter [inch]	3	1	1	5	-	Triangular
2.7 Productivity index (PI) [bbl/psi-d]	17	18	1	50	-	Lognormal
2.8 Average reservoir pressure (P_{res}) [psi]	Eq. S1	Eq. S1	24	14,738	-	Lognormal
2.9 Average reservoir temperature (T_{res}) [°F]	Eq. S3	Eq. S3	71	582	-	Normal
2.10 Offshore?	0	0	0	0	0.2	Binary
3. Fluid properties						
3.1 API gravity of produced crude [°API]	33	8	3	88	-	Normal
3.2 Associated gas composition [mol%]						
N_2	2	2	0	14	-	Lognormal
CO_2	6	4	0	35	-	Lognormal
C_1	84	5	62	100	-	Lognormal
C_2	4	2	0	15	-	Lognormal

C_3	2	1	0	10	-	Lognormal
C_{4+}	1	1	0	6	-	Lognormal
H_2S	0.5	1	0	1	-	Lognormal
4. Production practices						
4.1 Gas-to-oil ratio (GOR) [ssc/bbl oil]	Table S3	Table S3	1	34,000	-	Lognormal
4.2 Water-to-oil ratio (WOR) [bbl produced/bbl oil]	Eq. S4	Eq. S5	1.0	33	-	Lognormal
4.3 Water injection ratio [bbl injected/bbl oil]	WOR+1	0	WOR+1	WOR+1	-	Uniform
4.4 Gas lifting injection ratio [scf/bbl oil]	363	500	200	2500	-	Lognormal
4.5 Gas flooding injection ratio [scf/bbl oil]	Eq. S6	0	Eq. S6	Eq. S6	-	Uniform
4.6 Flood gas (1:Natural gas, 2: N_2, 3: CO_2)	1	0	1	1	-	Uniform
4.7 CO_2 flooding and sequestration parameters						
4.7.1 Percentage of newly acquired CO_2 (total injected CO_2 includes both new and recycled)	41	20	0	100	-	Normal
4.7.2 Source of CO_2 (1: Natural subsurface reservoir, 2: Anthropogenic)	1	0	1	1	-	Uniform
4.7.3 Percentage of sequestration credit assigned to the oilfield	0	0	0	0	-	Uniform
4.8 Steam-to-oil ratio (SOR) [bbl steam/bbl oil]	3.5	2	0	5	-	Lognormal
4.9 Fraction of required electricity generated onsite	0.5	0.25	0	1	-	Normal
4.10 Fraction of remaining gas reinjected	0.5	0.25	0	1	-	Normal
4.11 Fraction of water produced that is reinjected	0.77	0.38	0	1	-	Normal
4.12 Fraction of steam generation via co-generation	0.37	0.42	0	1	-	Normal
5. Processing practices						
5.1 Heater/treater	0	0	0	0	=IF(WOR>10,1,IF(WOR>5,0.5,IF(WOR>1,0.25,0)))	Binary
5.2 Stabilizer column	0	0	0	0	=IF(API>40,1,IF(API>30,0.5,IF(	Binary

						API>20,0.2 5,0)))	
5.3	Upgrader type (0: None, 1: Delayed coking, 2: Hydroconversion, 3: Hydroconversion and fluid coking)	0	0	0	0	0.0	Uniform
5.4	Associated gas processing path (1: None, 2: Minimal - Dehydrator, 3: Acid Gas, 4: Wet Gas, 5: Acid Wet Gas, 6: CO_2-EOR Membrane, 7: CO_2-EOR Ryan Holmes)	5	0	5	5	-	Uniform
5.5	Flare-oil-ratio (FOR) [scf flared/bbl oil]	NOAA	NOAA*0.2	1	3000	-	Normal
5.6	Ratio of venting to oil production	10	3	0	100	-	Normal
5.7	Volume fraction of diluent in diluted crude	0	0	0	0	-	Uniform
	6. Land use impacts						
6.1	Crude ecosystem carbon richness						
6.1.1	Low carbon richness (semi-arid grasslands)	0	0	0	0	0.33	Binary
6.1.2	Moderate carbon richness (mixed)	0	0	0	0	0.33	Binary
6.1.3	High carbon richness (forested)	0	0	0	0	0.33	Binary
6.2	Field development intensity						
6.2.1	Low intensity dev. and low oxidation	0	0	0	0	0.33	Binary
6.2.2	Moderate intensity dev. and moderate oxidation	0	0	0	0	0.33	Binary
6.2.3	High intensity dev. and high oxidation	0	0	0	0	0.33	Binary
	7. Crude oil transport						
7.1	Fraction of oil transported by each mode						
7.1.1	Ocean tanker	0	0	0	0	1	Binary
7.1.2	Barge	0	0	0	0	0	Binary
7.1.3	Pipeline	0	0	0	0	1	Binary
7.1.4	Rail	0	0	0	0	0	Binary
7.1.5	Truck	0	0	0	0	0	Binary
7.2	Transport distance (one way)						
7.2.1	Ocean tanker [mile]	8,000	2,000	1,000	12,000	-	Normal
7.2.2	Barge [mile]	NA	NA	NA	NA	-	NA
7.2.3	Pipeline [mile]	1,000	700	100	5,000	-	Normal

7.2.4 Rail [mile]	NA	NA	NA	NA	-	NA
7.2.5 Truck [mile]	NA	NA	NA	NA	-	NA
7.3 Ocean tanker size, if applicable [ton]	250,000	25,000	50,000	300,000	-	Normal
8. Other sources emissions						
8.1. Small sources emissions [g CO_2eg./MJ]	0.5	0.15	0.1	1	-	Normal

2. Additional Results

2.1. Allocation vs. displacement

As discussed in section 1.3, emissions from co-products can be assigned by either allocation in proportion to energy content as well as co-product displacement. Fig. S19 shows a comparison between CI curves using co-product displacement and allocation methods. The two methods result in almost similar CI estimates. In some cases with large co-production (i.e., a very gas-rich field, high GOR), the two co-product accounting methods can result in different outcomes. Similar supply curves could be drawn for each country for national-level emission mitigation analysis.

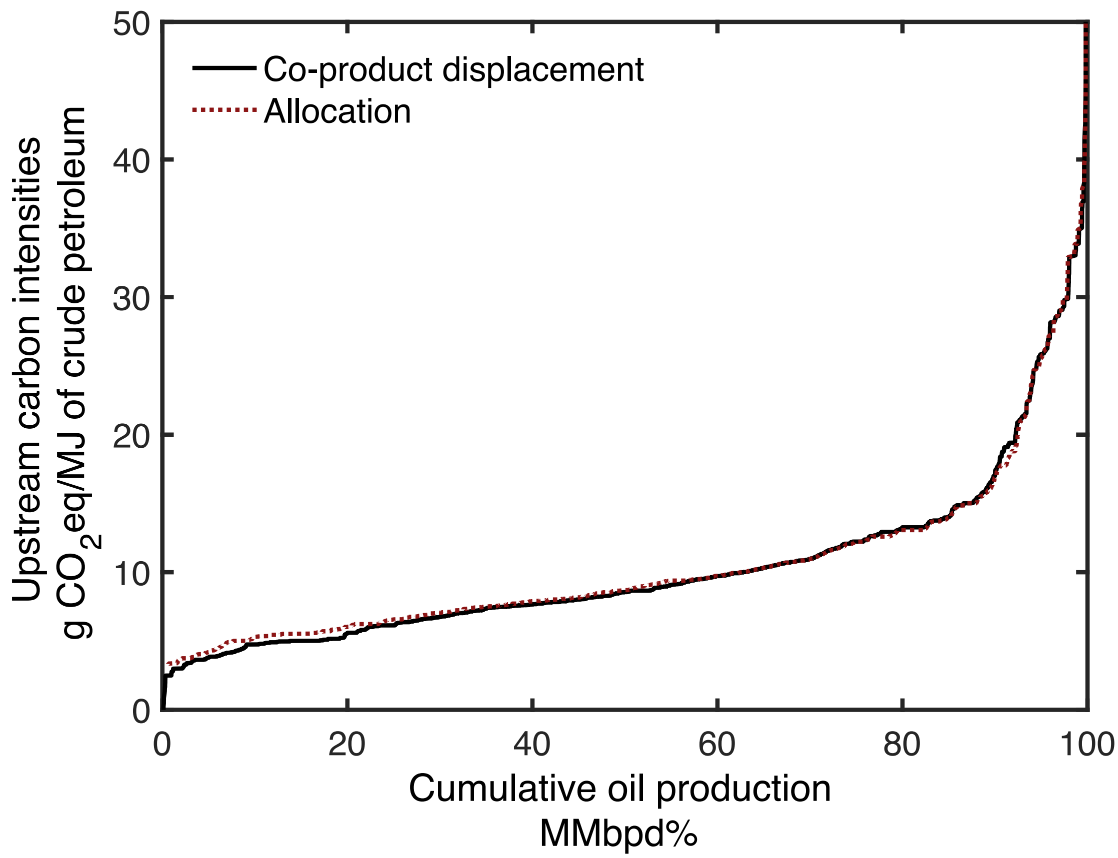

Fig. S19. Global field-level upstream carbon intensity curve (2015). Comparison between co-product displacement and allocation by energy methods.

2.2. Break down of emissions plot

The break-down of GHG intensities of each field is presented in Fig. S20. Surface processing has a dominant onsite contribution in the net GHG emissions of most of the studied fields. The emissions breakdown of surface processing is illustrated in Fig. S21. Among the process stages of surface processing, Stabilizer (processing practice) and Acid Gas Removal (AGR, associated gas processing path) are the major sources of GHG emissions.

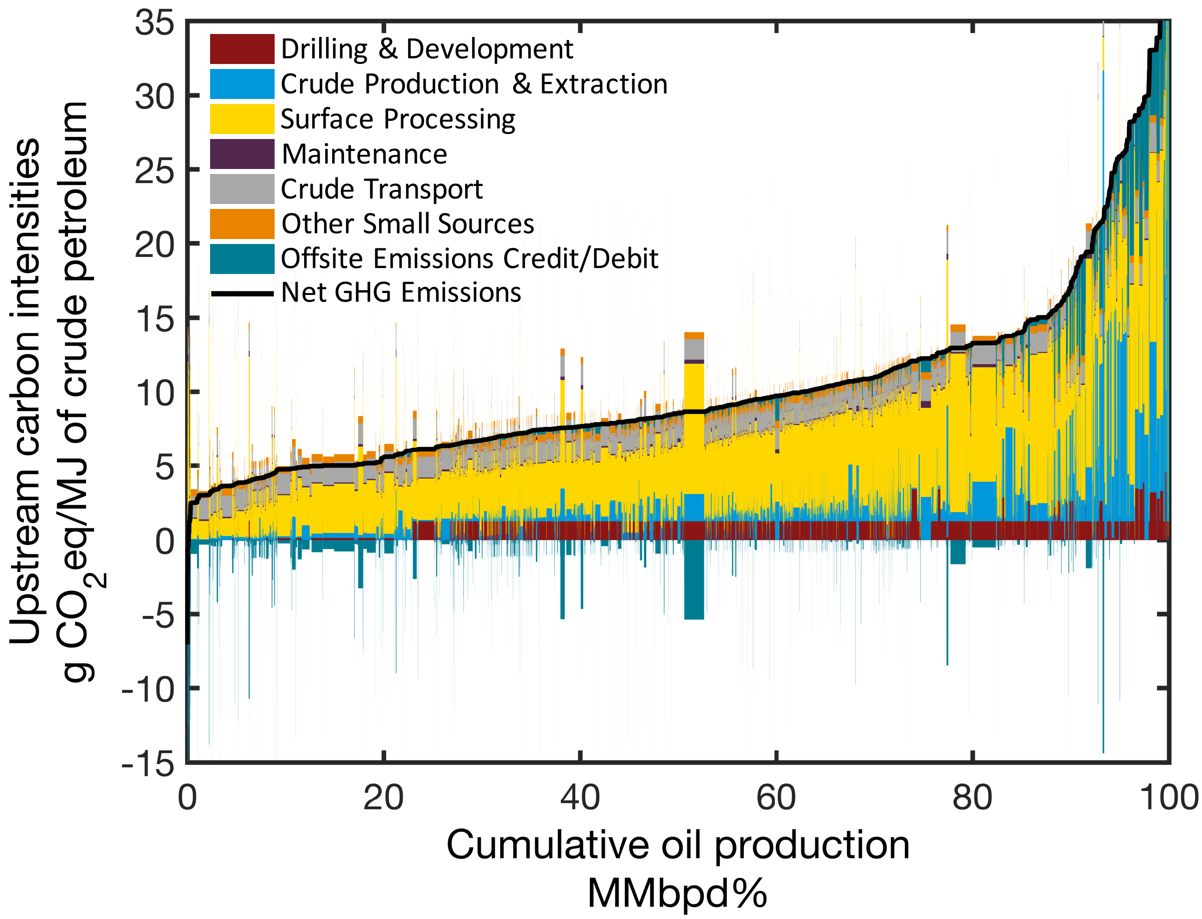

Fig. S20. Global field-level upstream carbon intensity curve with break-down of emissions (2015). The share of emissions (credit/debit) related to drilling & development, production & extraction, surface processing, maintenance, transport, other small sources, and offsite emissions. Co-product displacement approach is used to address the co-products.

A high volume of natural gas production (i.e., high GOR) sold as a co-product is the main driver of generating large emissions credit (green bars) for many of the global fields. There are 4,587 fields with an emissions credit with GHG emissions from NGL export as the main contributor of gaining credit.

The breakdown of field-level GHG intensities (VOC, CO, CH_4, N_2O, CO_2, and CO_2eq.) are presented in Result Data Excel file (Field-Level GHG Intensities sheet). The global volume-weighted average shares of VOC, CO, CH_4, N_2O, and CO_2 gases in CO_2eq. emissions are 0.6%, 0.4%, 34.4%, 0.1%, and 64.5%, respectively.

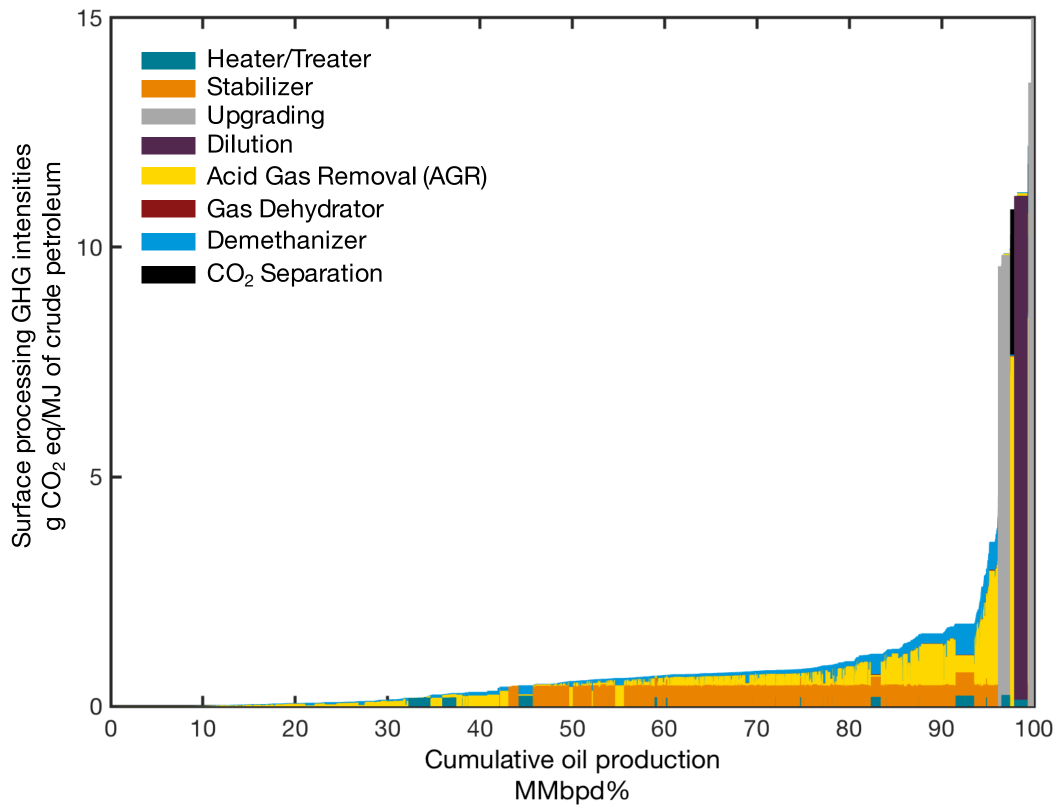

Fig. S21. Global field-level surface processing carbon intensity curve with break-down of emissions (2015). Co-product displacement approach is used to address the co-products.

2.3. Global map and data quality results

Fig. S22 presents the first global upstream CI map with country-level volume-weighted-average CI estimates and their corresponding error bars.

Following the methodology described in section 1.4.6, Figs. S23 and S24 show the country-level volume-weighted average data quality scores of the same countries that are presented in Figs. 1 and S22 (see Results Data Excel sheet for the full list). The countries with available oil and gas data from government sources (e.g. Nigeria, UK, Denmark, Norway, Canada, and California/USA) have higher data quality scores. On the other hand, some other

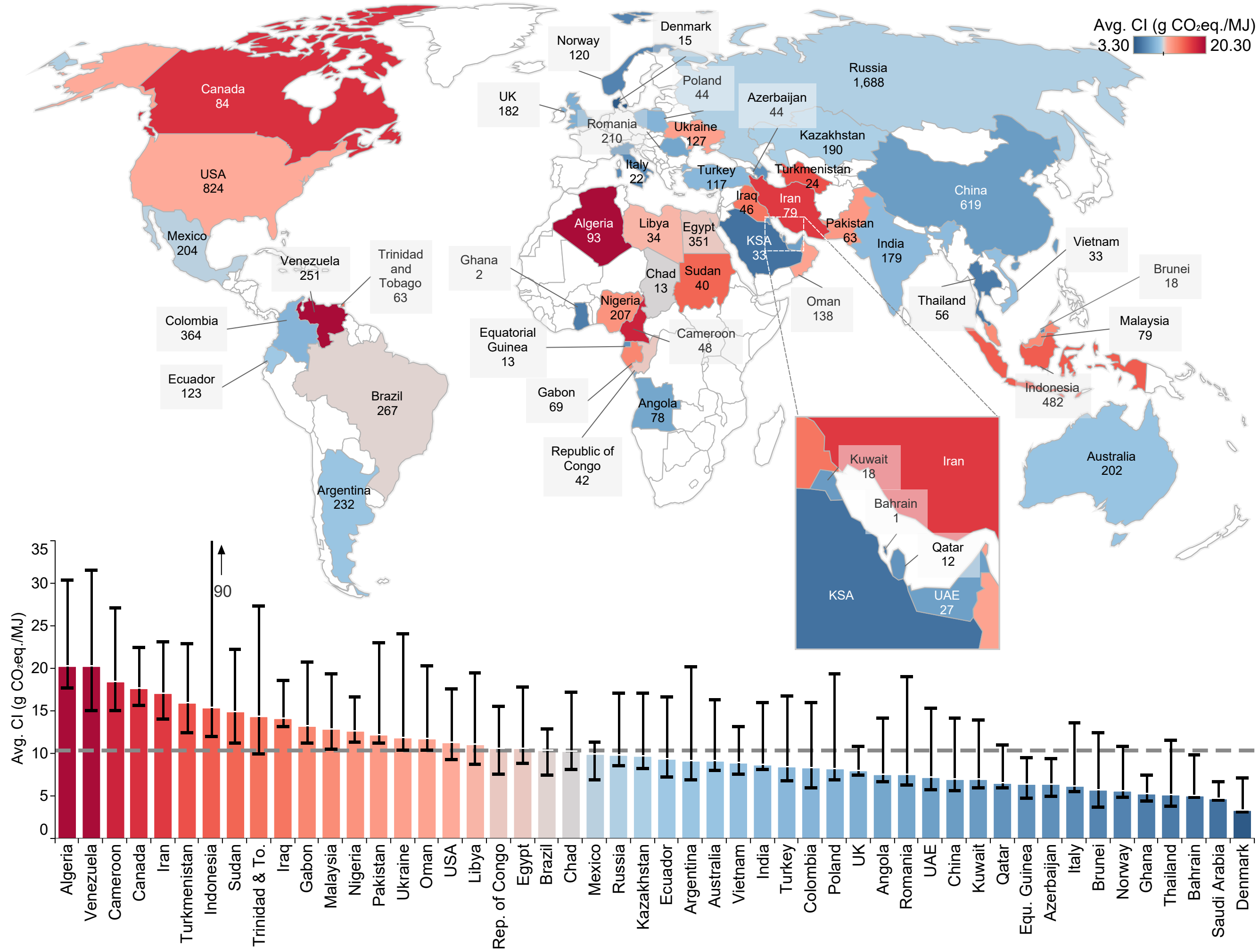

Fig. S22. Estimated global crude oil upstream carbon intensity (2015): national volume-weighted-average upstream GHG intensities in g CO_2eq./MJ crude oil delivered to refinery (color) with corresponding error bars (5-95%ile of Monte Carlo simulation to explore the uncertainty associated with missing input data, see SM section 1.7 and 2.4). Map shows number of fields analyzed below each country name. The global volume-weighted CI estimate is shown by the dashed line (~10.3 g CO_2eq./MJ). Reference year is 2015. Only countries with ≥0.1% of global oil production share are mapped (see the SM Results Data Excel file for full list). Color scheme reflects national volume-weighted-average CI: dark blue for lowest CI, dark red for highest CI.

major crude oil producers (e.g. Russia) score very low due to lack of data. Figs. S23 and S24 reveal that despite the labor intensive data gathering undertaken in this study, there is still a large gap that needs to be covered by making oil & gas data more accessible in public domain in order to attain satisfactory quality scores and more reliable life-cycle GHG emissions estimates.

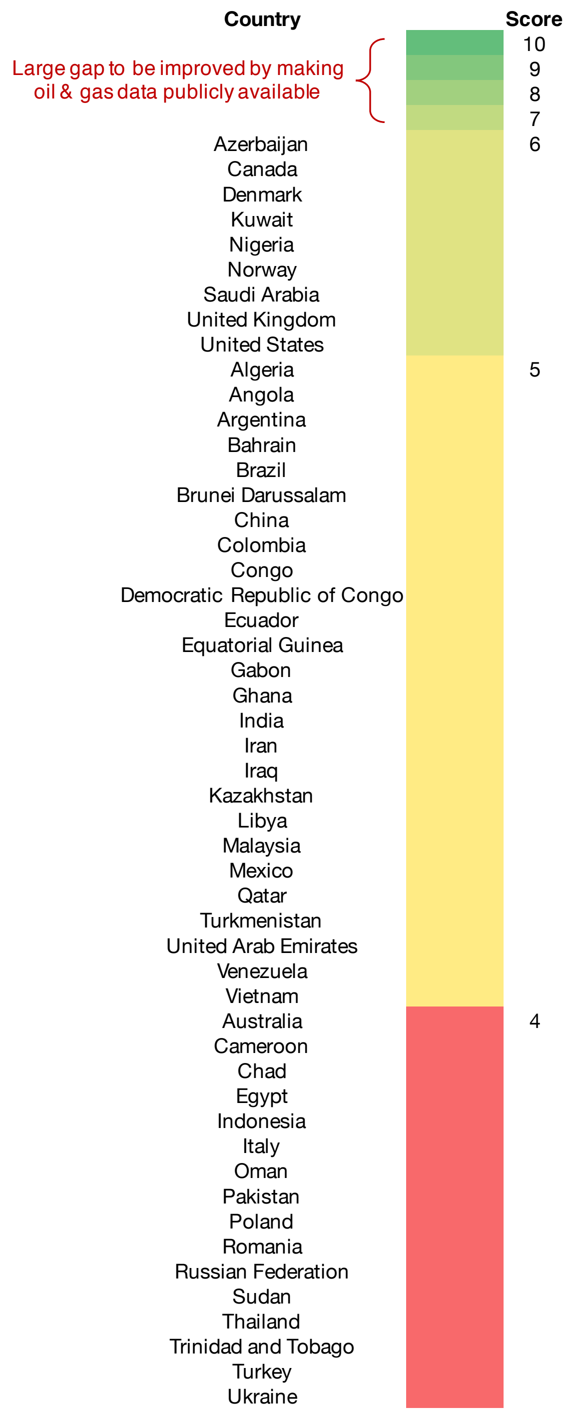

Fig. S23. Country-level volume-weighted-average data quality scores. Only countries with >=0.1% global oil production share are presented (see Results Data Excel file for full list).

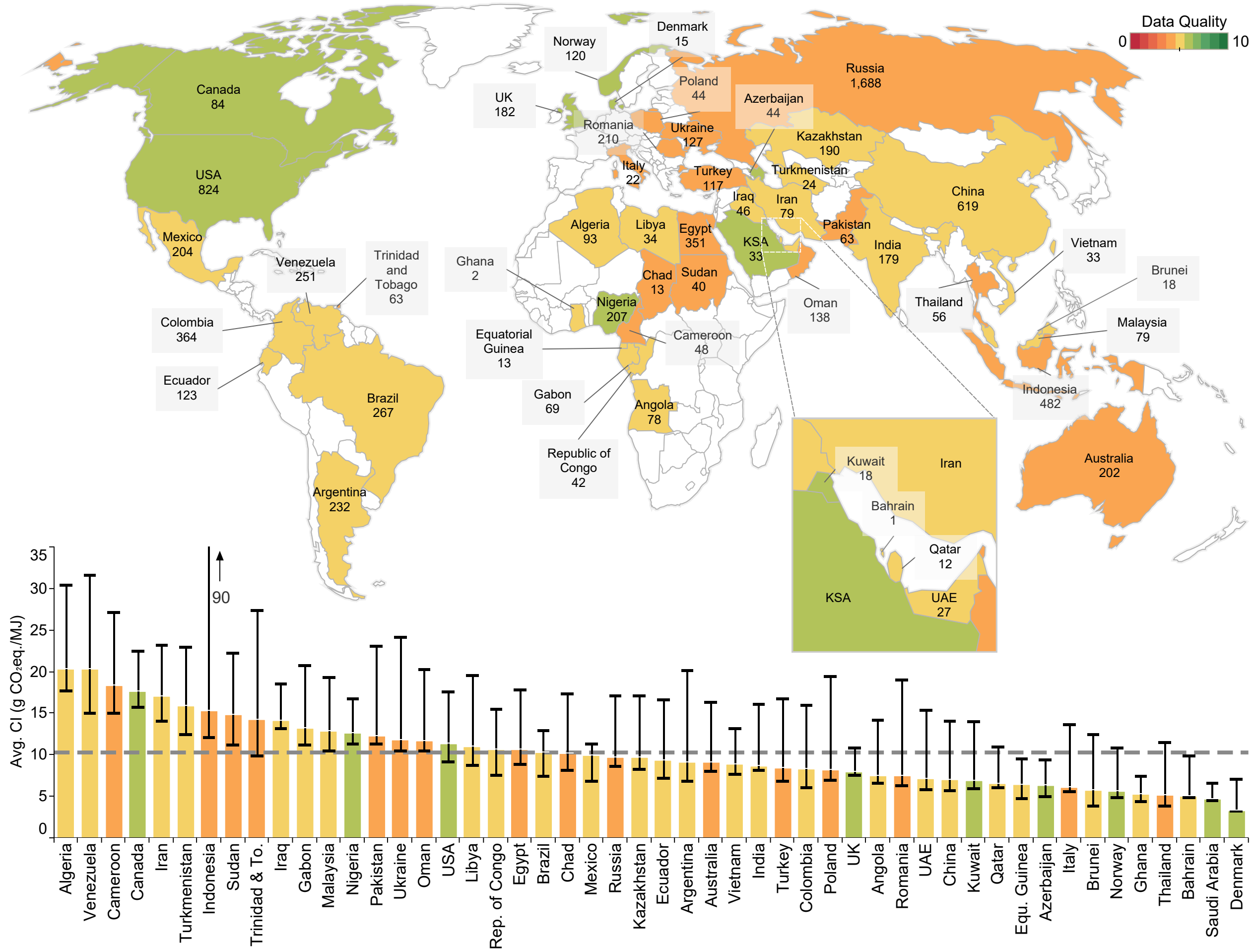

Fig. S24. National volume-weighted-average data quality scores and GHG intensities (bar chart). Map shows number of fields analyzed below each country name. The global volume-weighted CI estimate is shown by the dashed line (~10.3 g CO_2eq./MJ). Reference year is 2015. Only countries with ≥0.1% of global oil production share are mapped (see the SI Results Data Excel file for full list). Color scheme reflects volume-weighted average data quality score: dark red for lowest score (0), dark green for highest score (10).

2.4. Carbon intensity curve uncertainty analysis

Following the methodology described in section 1.7, the CI estimate uncertainty modeled in Fig. S25 relates to the use of model defaults for missing data. When an input datum is not available, OPGEE supplies a default value derived from statistical analysis of the petroleum engineering literature and commercial datasets (see section 1.4.3). Monte Carlo (MC) simulations in Fig. S25 replaced missing data for each oilfield with values from the governing distributions (500 simulations, see section 1.7). Despite extensive data gathering efforts and utilization of commercial datasets, the CI dispersion and the low data quality scores for certain countries highlight the need for improved data from most producing countries (see section 1.4.6 and 2.3). Fig. S25 shows that static OPGEE defaults used without MC analysis (black curve in Fig. S25 which is identical to Fig. 2 CI curve) result in conservatively low estimates of the CI near the 25%ile probability curve for the MC analysis.

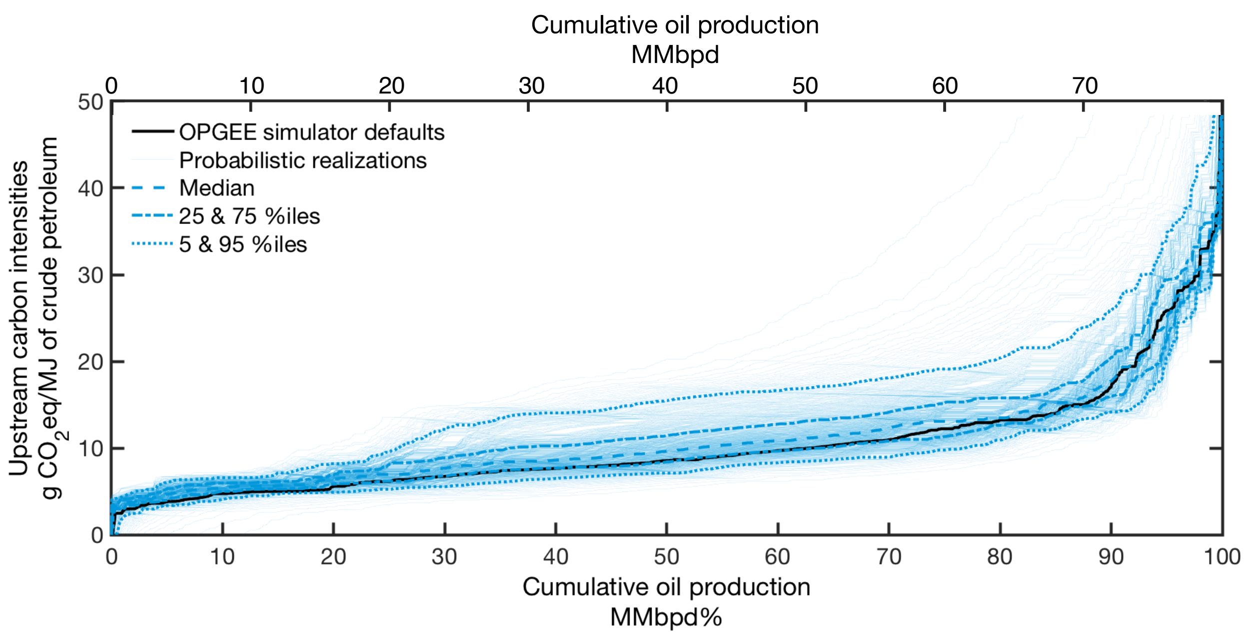

Fig. S25. CI probabilistic uncertainty associated with the fields' missing input data using a Monte Carlo simulation (500 realizations per field). The narrower dispersion for the lowest and highest CI 5%iles is due to relatively higher data quality of the corresponding fields, e.g. in Denmark/Norway and California (USA)/Canada/Nigeria, respectively.

2.5. Mitigation case studies

Following the GHG emissions mitigation case studies introduced in section 1.2.2, the CI curves for four hypothetical mitigation case studies are shown in Fig. S26. See the manuscript main text for more details.

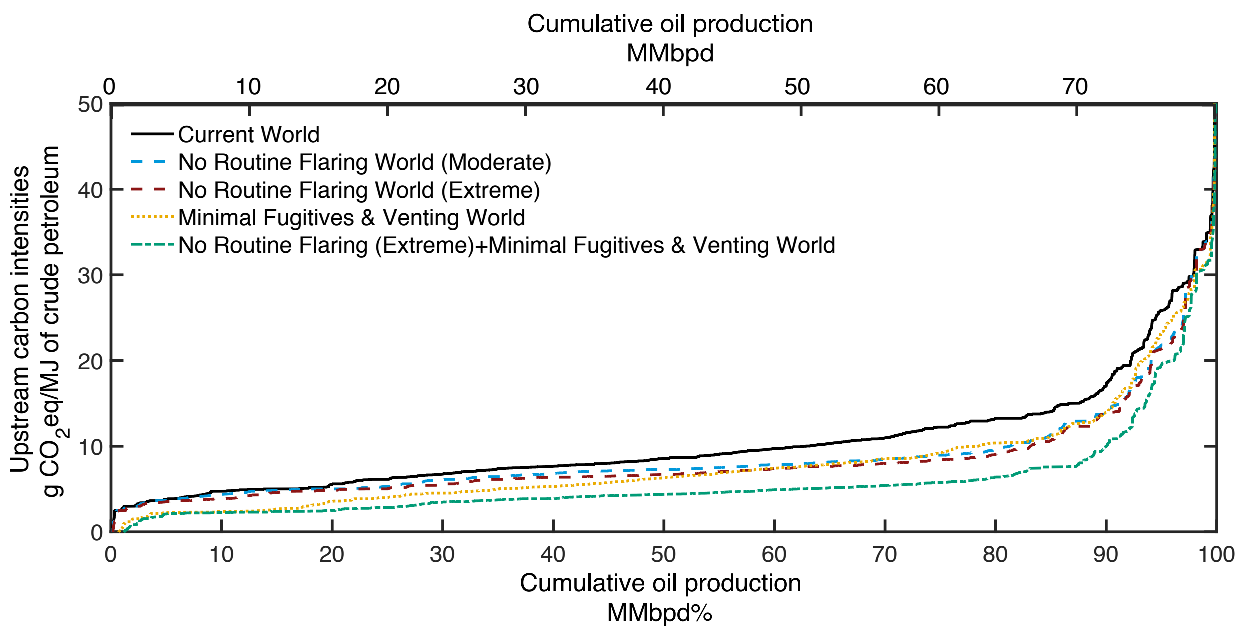

Fig. S26. Effect of hypothetical flaring (moderate and extreme) and methane fugitives/venting reduction cases on the CI curve.

2.6. Effect of gas venting

As discussed in section 1.2.4, gas venting is assumed zero throughout the study due to lack of data. Here we examine the effect of venting on the global CI curve. As presented in Fig. S27, by venting 10%, 20%, and 50% of upstream flared gas from the global oilfields, the global volume-weighted average upstream CI increase from 10.3 g CO_2eq./MJ (no gas venting) to 11.4, 12.5, and 15.7 g CO_2eq./MJ, respectively. Less sensitivity for the lowest and highest CI fields is due to lower gas flaring of the corresponding oilfields, e.g. in Denmark/Norway and Canada (oil sands), respectively.

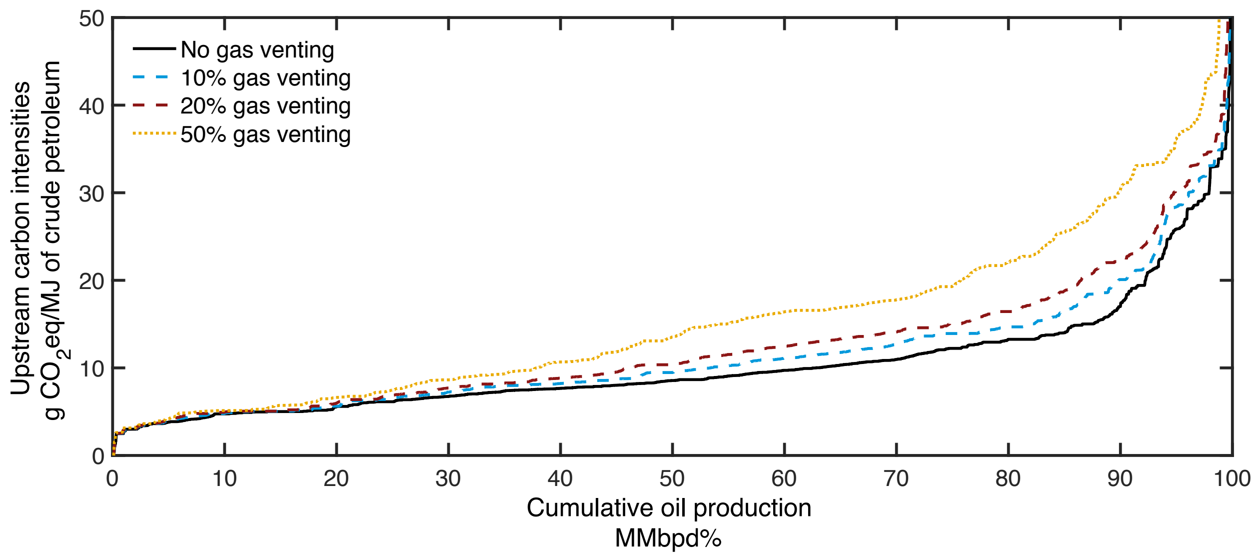

Fig. S27. Global field-level upstream carbon intensity curve (2015). Effect of gas venting (instead of flaring) on the global CI curve.

3. Validation of Model Against Global Reported Emissions Datasets

The most detailed sector-specific global reporting of oil and gas sector GHG emissions is generated yearly by the International Association of Oil and Gas Producers (IOGP, formerly OGP) (*61*). These IOGP data are likely to be much more granular and realistic than national-scale estimates such as those reported under United Nations Framework Convention on Climate Change (UNFCCC) inventory methods. This is because IOGP collects emissions data directly from producers and recommends on a detailed, "bottom-up" oil and gas industry-specific inventory method (*62*, *63*) rather than using the coarser sector-scale estimates used in the Intergovernmental Panel on Climate Change (IPCC) inventory methods (*64*, *65*).

IOGP reports member companies' emissions to air and water, as well as energy use, in their yearly "Environmental Performance Indicators" (EPI) document (*66*). In the EPI document containing year 2015 data, there were 56 member operating companies which reported data for operations in 75 countries. IOGP member companies produce ~28% of global hydrocarbon (HC) production (scale to ~1.2 Gt CO_2eq. industry wide) but represent a variable share of production depending on the world region (*66*) (p. 7). For example, in Europe, IOGP members produce 88% of total HCs, while in the Former Soviet Union, IOGP members only produce 10% of total HCs (see Table S11). Therefore, IOGP data should be expected to be more or less representative of HC operations depending on the region.

IOGP reports emissions of a variety of gases (CO_2, CH_4, non-methane volatile organic compounds, or NMVOCs). IOGP also breaks down emissions by region and, in some cases, by source (e.g., flare, combustion, vents, fugitives). Gross IOGP reported emissions by region and gas are presented in Table S11 (*66*) (Table A3).

If we assume that IOGP members in a region are representative of the producers in their region, we can scale IOGP emissions to estimate global emissions from the HC sector by region and then sum to generate a global emissions figure comparable to ours. As IOGP uses AR4 GWP, we re-scale CO_2, CH_4, and NMVOC emissions using AR5 GWPs of 1, 30, and 4.5 for CO_2, CH_4, and NMVOC, respectively, as used in our analysis (see section 1.2.1). The resulting emissions in CO_2eq. are presented for each region in Table S12. We see that these IOGP emissions are significantly lower than the OPGEE-estimated emissions from this analysis, with a gap of ~500 Mt CO_2eq.

We examine three key sources to determine where additional emissions might be expected in our OPGEE models than in IOGP results: flaring, transport of crude, and land use change. Because we cannot examine the IOGP data or models, we can only test these sources of variability by changing OPGEE data inputs or assumptions to align with IOGP assumptions or analysis boundaries, then see the resulting emissions change.

Table S11. IOGP reported fractional share of coverage (IOGP 2016, Table A1). IOGP reported emissions by gas (CO_2, CH_4, NMVOC, IOGP 2016 Table A3).

	Fraction of BP production*	**Gross CO_2 emissions**	**Gross CH_4 emissions**	**Gross NMVOC emissions**
	IOGP HC tonnes /BP HC tonnes	10^6 tonnes	10^3 tonnes	10^3 tonnes
Africa	0.61	66.95	360.87	158.12
Asia/Australia	0.33	50.13	300.31	5.31
Europe	0.88	29.9	143.65	3.96
Former Soviet Union	0.1	12.21	59.76	129.78
Middle East	0.23	24.94	48.45	120.34
North America	0.17	68.43	755.22	202.63
South & Central America	0.43	27.82	151.43	159.29

* Based on global production as reported in BP Statistical Review of World Energy 2016 (*67*).

Table S12. Comparison of scaled IOGP global emissions to OPGEE global emissions from this study.

	Expected global emissions			
	CO_2 emissions [10^6 tonnes]	CH_4 emissions [10^6 tonnes]	NMVOC emissions [10^6 tonnes]	Total CO_2eq. [10^6 tonnes]
IOGP scaled to global	993.4	7.26	3.66	1227.9
OPGEE	1100.32	19.73	2.30	1722.4

3.1. Flaring

First, we examine flaring assumptions in each analysis. IOGP collects flaring data, reported in tonnes of HC gas flared from producers (*66*) (Table A12). In order to generate a global flaring estimate, these flaring rates can be regionally scaled assuming that IOGP members are representative of the all producers in their reporting region. The resulting amounts of HC gas flared are reported in Table S13, and we see a globally-scaled IOGP flaring rate of ~82 Mt HC flared.

In contrast, our OPGEE analysis assigns either government-reported flaring for a given field (less common) or country-level default flaring intensities from NOAA satellite data (most cases). Our country-level intensities are derived from reported flaring rates satellite measurements from NOAA VIIRS Nightfire program (*30*, *68–70*). Grouping country-level gross flaring rates in billion cubic meters (BCM), then converting to mass of HC gas flared, assuming the OPGEE default gas composition, our flaring results are given in Table S14. The VIIRS data result in an overall flaring rate of ~120 Mt HC. We see that averaged over the globe, VIIRS estimates 1.5 times larger flaring mass combustion rate than globally-scaled IOGP-reported flaring results.

Table S13. IOGP flaring results (Columns 1 and 2 from IOGP 2016, Table A12, remainder author calculations).

	Total HC production	**Flaring intensity**	**Gross flaring from IOGP members**	**Scaled to all producers**
	1000 tonnes of HC	tonnes HC flared per 1000 tonnes HC produced	1000 tonnes HC flared	1000 tonnes HC flared
Africa	350000	39.42	13797.0	22618.0
Asia/Australia	293000	19.22	5631.4	17065.0
Europe	326000	3.77	1229.0	1396.6
Former Soviet Union	136000	7.69	1045.8	10458.4
Middle East	460000	5.72	2631.2	11440.0
North America	292000	8.74	2552.1	15012.2
South & Central America	239000	6.89	1646.7	3829.6
Global				81819.9

Table S14. Flaring volumes and estimated mass from VIIRS results assuming OPGEE default gas compositions. Flaring in mass from VIIRS BCM assuming OPGEE default raw gas composition with MW of 19.64 g/mol.

	VIIRS total 2015 flaring	**Gross flaring converted to mass**	**Ratio of VIIRS/IOGP**
	BCM	1000 tonnes HC flared	tonne/tonne
Africa	30.2	24659.0	1.1
Asia/Australia	12.7	10408.7	0.6
Europe	2.0	1598.2	1.1
Former Soviet Union	30.1	24560.2	2.3
Middle East	42.9	35051.7	3.1
North America	14.9	12146.7	0.8
South & Central America	13.6	11095.5	2.9
Global		119520.1	1.5

In addition to the 1.5 times different assumptions for amounts of gas flared, OPGEE default assumptions about flare combustion efficiency differ from IOGP assumptions. IOGP guidance requires use of the 2009 API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry (henceforth referred to as "API Compendium") (*64*), which recommends a default flare combustion efficiency of 98%. OPGEE, on the other hand, assumes a default flare combustion efficiency of 95% (see section 1.2.4).

Thus, OPGEE flaring methods should be expected to result in additional CO_2 and CH_4 emissions compared to IOGP flaring methods. The total difference in CH_4 emissions is the sum of additional CH_4 able to be emitted due to larger flaring mass rates as well as a larger mole fraction of CH_4 able to be emitted. At OPGEE default gas compositions, switching OPGEE assumptions to IOGP assumptions would result in a decrease of 3 $MtCH_4$.

To determine a reasonable range of overall impact of these flaring methods differences in CO_2eq., we construct three indicative gas composition cases: OPGEE default, Rich gas, and Dry gas (see Table S15). Depending on the assumed typical gas composition, we see that changing OPGEE flaring methods and data to IOGP methods and data would reduce emissions by 158 to 193 $MtCO_2$eq. These different assumptions result in 15% to 22% increased CO2eq. emissions in OPGEE.

3.2. Transport

Another difference between IOGP methods and our OPGEE methods is that OPGEE includes transport of crude oil to the refinery inlet gate. In this analysis, all fields are given a default transport distance of ~5000 mi via ocean tanker transport and 750 mi via pipeline transport. Pipeline and tanker transport fuel use is from the U.S. DOE GREET model (*71*).

The IOGP EPI document reports emissions for the upstream industry (sometimes called "E&P" operations) and does not appear to include long-distance transport via tanker or pipeline. IOGP defines the "upstream industry" to include "Those operations within the industry to the point where the produced resource is metered into the transportation system. This includes Exploration and Production" (*66*) (p. 83). IOGP figures can be expected to include transport of liquids and gases to central gathering points, terminals, or long-distance pipeline terminus.

Because it is unknown what fraction of OPGEE-estimated total transport energy use would occur before the resource is transported to the edge of the IOGP boundary, we explore cases where 80% to 90% of OPGEE transport emissions would be excluded if IOGP methods and analysis boundaries were adopted. This method alignment would result in an expected 188 to 223 $MtCO_2eq.$ reduction in OPGEE estimates.

Table S15. Three indicative gas composition cases to explore range of effects of differences in both flaring volume and flare destruction efficiency.

		OPGEE def.	Rich gas	Dry gas
Molar fraction	CH_4	0.84	0.70	0.90
	C_2H_6	0.04	0.125	0.03
	C_3H_8	0.02	0.06	0.01
	C_4H_{10}	0.01	0.025	0
	CO_2	0.06	0.06	0.03
	N_2	0.02	0.02	0.02
	H_2S	0.01	0.01	0.01
kg CO_2eq./kg HC gas	@ 95% DE	3.36	3.22	3.60
	@ 98% DE	2.80	2.79	2.94
Fraction CO_2eq.	@ 95% DE	68.6%	74.4%	66.1%
	@ 98% DE	84.9%	88.2%	83.4%
Fraction CH_4	@ 95% DE	30.5%	23.1%	33.4%
	@ 98% DE	14.7%	10.6%	16.4%
Fraction NMVOC	@ 95% DE	0.9%	2.4%	0.5%
	@ 98% DE	0.4%	1.1%	0.2%
Ratio of 95% CO_2eq. to 98% CO_2eq.		1.20	1.15	1.22

3.3. Land use

Lastly, OPGEE by default includes CO_2 emissions due to land clearance and land disturbance, while the API Compendium (and therefore IOGP-reported values) does not include emissions from land use change. OPGEE applies default assumptions that result in no emissions for offshore fields and "moderate" assumptions for land-based fields. Land use emissions across our OPGEE runs contribute 7.2% of total CO_2 GHG emissions. This corresponds to 125

$MtCO_2eq.$ of emissions that would be removed after aligning OPGEE methods with IOGP methods.

3.4. Remaining discrepancies

As noted above in Table S12, OPGEE central results are ~500 $MtCO_2eq.$ larger than globally-scaled IOGP emissions. After accounting for the major modeling differences noted above, the resulting differences between OPGEE and IOGP are summarized in Table S16. Notably, the overall miss-alignment in $MtCO_2eq.$ is largely corrected by making these three gross adjustments to align OPGEE methods with IOGP methods.

However, despite this large reduction in differences between OPGEE and IOGP predictions, additional differences remain after this adjustment. Most notably: OPGEE CH_4 emissions remain higher than IOGP CH_4 emissions.

We believe that the globally-scaled IOGP CH_4 emissions rates are most likely underestimates of global methane emissions from the oil and gas sector. The IOGP globally-scaled CH_4 emissions from Table S12 are 7.26 $MtCH_4/y$. A few comparisons to this figure are instructive. First, BP statistical review estimates 2015 global gas production of 342.7 BCF/d, or 410 Gmol/d (*72*). Assuming a plausible CH_4 molar fraction of 0.8 mol CH_4/mol gas in raw gas produced from the earth, this amounts to 5.26 $MtCH_4/d$ or 1920 $MtCH_4/y$. The globally-scaled IOGP methane emissions of 7.26 $MtCH_4/y$ therefore amount to 0.38% of global methane production. Given recent work on methane emissions from oil and gas (*73*), this loss factor is almost certainly too small. Another comparison can be made to the Global Carbon Project (GCP) methane budget (*74*, *75*). GCP estimates oil and gas related emissions to be 77.6-93.7 $MtCH_4/y$, a factor of 10-13x larger than globally-scaled IOGP emissions.

In contrast, OPGEE estimates above of 19.7 $MtCH_4/y$ seem more reasonable. Since our analysis focuses on oilfields, we miss some dry gas production. For our 8,966 fields, multiplying the daily oil production rate by the GOR results in production of 100.5 BCF/d, or 29% of BP total global gas production. The remainder of global gas must come from fields that are listed as dry gas fields in production databases and therefore not included in our analysis. If the remainder 71% of global gas production comes from dry gas fields with a CH_4 loss rate of 2% across the entire value chain, additional dry gas emissions would be 27.3 $MtCH_4/y$, for total emissions of ~47 $MtCH_4/y$ when added to our model estimate. This amounts to 2.4% total methane loss across the value chain compared to BP raw methane production (47 $MtCH_4$/1920 $MtCH_4$). Thus, OPGEE results are more plausible than the above IOGP-derived 0.38%, though still smaller than GCP methane inventory values.

Table S16. Adjusting OPGEE boundaries to align with IOGP boundaries.

Difference estimates	**Low**	**High**	
Flaring	157.6	192.9	$MtCO_2eq.$
Transport	187.9	223.1	$MtCO_2eq.$
Land use	125.5	125.5	$MtCO_2eq.$
Difference to be explained	494.5	494.5	$MtCO_2eq.$
Remaining difference	23.5	-47.0	$MtCO_2eq.$

Table S17. Public literature sources used in this study. For the government data see references (*26*, *35*) for Norway, (*36–39*) for Canada, (*40*) for Denmark, (*41*) for the UK, (*42*) for Nigeria, (*43*) for California (US), (*44*) for Alaska (US), and (*45*) for the U.S. shale oils.

Field name	Country	Reference
Hassi Messaoud	Algeria	(*76–85*)
HBNS	Algeria	(*86–89*)
Ourhoud	Algeria	(*90–93*)
Hassi R'Mel	Algeria	(*94–98*)
Dalia/Camelia	Angola	(*99*, *100*)
Kissanje	Angola	(*101*)
Girassol	Angola	(*102–104*)
Kuito	Angola	(*105–108*)
Takula	Angola	(*109–114*)
Acacia	Angola	(*115–117*)
Plutao	Angola	(*118–120*)
Cerro Dragon Area	Argentina	(*121–123*)
Kingfish	Australia	(*124*, *125*)
Cossack	Australia	(*126–135*)
Azeri	Azerbaijan	(*136–139*)
Jubarte (1 & 2)	Brazil	(*140*)
Frade	Brazil	(*141–145*)
Lula-Iracema	Brazil	(*146–151*)
Marlim	Brazil	(*152–155*)
Marlim Sul	Brazil	(*156–158*)
Roncador	Brazil	(*159*, *160*)
Sapinhoa	Brazil	(*161*, *162*)
Barracuda	Brazil	(*163–167*)
Peregrino	Brazil	(*168–172*)
Albacora Leste	Brazil	(*173–176*)
Baleia Azul	Brazil	(*177–179*)
Jackfish	Canada	(*180–183*)
Hibernia	Canada	(*184–186*)
Terra Nova	Canada	(*187*)
Midale	Canada	(*188–190*)
Huizhou 21-1	China	(*191–199*)
Qinhuangdao 32-6	China	(*200–203*)
Bozhong	China	(*204–213*)
Ansai	China	(*214–217*)
Jingan	China	(*218*)
Karamay	China	(*219–221*)

Lamadian	China	(*222*)
Saertu	China	(*222*, *223*)
Tahe	China	(*224*, *225*)
Xingshugang	China	(*226*, *227*)
Jiyuan	China	(*228*)
Penglai 19-3	China	(*229*)
Suizhong 36-1	China	(*230*)
Fengcheng	China	(*231*, *232*)
Castilla	Colombia	(*233*, *234*)
Cano Limon	Colombia	(*235–238*)
Quifa Southwest	Colombia	(*239*)
Rubiales	Colombia	(*240–242*)
Cusiana	Colombia	(*236*, *243–247*)
Chichimene	Colombia	(*248–250*)
Mobim	Congo	(*251*, *252*)
Likouala	Congo	(*253*)
M`Boundi	Congo	(*253*)
Sacha	Ecuador	(*254*)
Shushufindi-Aguarico	Ecuador	(*255–257*)
Bombay High	India	(*258–264*)
Mangala	India	(*265–272*)
Duri	Indonesia	(*273–277*)
Minas	Indonesia	(*278–282*)
Banyu Urip	Indonesia	(*283–287*)
Abuzar	Iran	(*288–294*)
Ahvaz	Iran	(*153*, *295–302*)
Gachsaran	Iran	(*303–306*)
Karanj	Iran	(*307–311*)
Marun	Iran	(*312–318*)
Agha Jari	Iran	(*319–326*)
Darkhovin	Iran	(*327*, *328*)
Rag-e-Sefid	Iran	(*153*), (*329–332*)
Parsi	Iran	(*309*, *333*)
Mansuri	Iran	(*85*, *334–344*)
Cheshmeh Khosh	Iran	(*318*, *345–347*)
Doroud	Iran	(*348–351*)
Kupal	Iran	(*352–358*)
Shadegan	Iran	(*85*, *334*, *359–362*)
BiBi Hakimeh	Iran	(*363–365*)
Salman	Iran	(*366–370*)

Tawke	Iraq	(*253*)
Ahdab	Iraq	(*371*, *372*)
Halfaya	Iraq	(*153*), (*373–376*)
Kirkuk (Baba Dome)	Iraq	(*377–386*)
Khurmala Dome	Iraq	(*387–391*)
Majnoon	Iraq	(*153*), (*392–395*)
Rumaila (1 & 2)	Iraq	(*312*), (*396–398*)
Taq Taq	Iraq	(*399–403*)
West Qurna 1 (a & b), West Qurna 2	Iraq	(*404–414*)
Zubair 1	Iraq	(*415–419*)
Zubair 2	Iraq	(*153*), (*420–424*)
Bai Hassan	Iraq	(*425*)
Garraf	Iraq	(*426*)
Val d`Agri	Iraq	(*427–429*)
Akshabulak Central	Kazakhstan	(*430*)
Tengiz	Kazakhstan	(*431–441*)
Kalamkas	Kazakhstan	(*432*)
Uzen	Kazakhstan	(*442*, *443*)
Magwa	Kuwait	(*444–449*)
Minagish	Kuwait	(*450–456*)
Raudhatain	Kuwait	(*421*, *424*, *457–462*)
Burgan	Kuwait	(*463–476*)
Sabriyah	Kuwait	(*477–484*)
Umm Gudair	Kuwait	(*153*), (*485–493*)
Ratawi	Kuwait	(*494*, *495*)
Waha	Libya	(*496–500*)
Messla	Libya	(*153*)
Bouri	Libya	(*501–504*)
Gumusut-Kakap	Malaysia	(*505–509*)
Cantarell	Mexico	(*68*, *510–520*)
Chuc	Mexico	(*47*, *521*, *522*)
Ku-Maloob-Zaap	Mexico	(*523–531*)
Xanab	Mexico	(*532*, *533*)
Tsimin	Mexico	(*534*, *535*)
Agbami	Nigeria	(*536–540*)
Bonga	Nigeria	(*521*, *540–542*)
Escravos Beach	Nigeria	(*521*, *540*)
Obagi	Nigeria	(*540*, *543*, *544*)
Pennington	Nigeria	(*521*, *540*, *545*)
Usan	Nigeria	(*521*, *540*, *546–548*)

Ekofisk	Norway	(*549–556*)
Gullfaks	Norway	(*557*, *558*)
Snorre	Norway	(*559*, *560*)
Statfjord	Norway	(*561*, *562*)
Valhall	Norway	(*563*, *564*)
Mukhaizna	Oman	(*565–571*)
Nimr	Oman	(*572–578*)
Safah	Oman	(*579–584*)
Dukhan	Qatar	(*585–591*)
Bul Hanine	Qatar	(*592–595*)
Al Shaheen	Qatar	(*596–599*)
Idd El Shargi North Dome	Qatar	(*600–604*)
Arlanskoye	Russia	(*605*, *606*)
Chaivo	Russia	(*253*), (*607–614*)
Fyodorovskoye	Russia	(*253*)
Malobalykskoye	Russia	(*253*)
North Labatyuganskoye	Russia	(*253*)
Novoyolkhovskoye	Russia	(*615*, *616*)
Povkhovskoye	Russia	(*253*, *617–619*)
Priobskoye North	Russia	(*253*)
Priobskoye South	Russia	(*253*, *620–625*)
Prirazlomnoye	Russia	(*253*)
Romashkinskoye	Russia	(*253*)
Russkinskoye	Russia	(*626*)
Samotlorskoye	Russia	(*253*)
Talakanskoye	Russia	(*253*)
Tevlinsko-Russkinskoye	Russia	(*253*)
Ust-Tegusskoye	Russia	(*253*, *626*)
Vankorskoye	Russia	(*253*)
Verkhnechonskoye	Russia	(*253*)
South Russia Fields	Russia	(*253*)
Vat-Yoganskoye	Russia	(*253*)
Mamontovskoye	Russia	(*253*)
Abu Hadriyah	Saudi Arabia	(*253*), (*627*)
Safaniyah	Saudi Arabia	(*253*), (*628*)
Abqaiq	Saudi Arabia	(*253*), (*629*, *630*)
Zuluf	Saudi Arabia	(*253*, *628*, *631*, *632*)
Qatif	Saudi Arabia	(*253*), (*633*)
Shaybah	Saudi Arabia	(*253*), (*634*, *635*)
Khurais	Saudi Arabia	(*253*), (*636–638*)

Khursaniyah	Saudi Arabia	(*253*), (*627*)
Abu Sa`fah	Saudi Arabia	(*253*), (*639*)
Berri	Saudi Arabia	(*253*), (*627*, *640–642*)
Ain Dar	Saudi Arabia	(*253*), (*628*, *643–645*)
Shedgum	Saudi Arabia	(*253*), (*628*, *644*, *646*)
Uthmaniyah	Saudi Arabia	(*253*, *628*, *644*, *646*, *647*)
Haradh	Saudi Arabia	(*253*, *628*, *633*, *644*, *648*)
Hawiyah	Saudi Arabia	(*253*), (*628*, *644*)
Manifa	Saudi Arabia	(*253*), (*649–651*)
Nuayyim	Saudi Arabia	(*652*), (*653*)
Marjan	Saudi Arabia	(*654*)
Mazalij	Saudi Arabia	(*655–657*)
Hawtah	Saudi Arabia	(*658–661*)
Lawhah	Saudi Arabia	(*654*)
Dzheitune (Lam)	Turkmenistan	(*662*, *663*)
Asab	UAE	(*153*, *664–669*)
Bab (Murban Bab)	UAE	(*670–674*)
Bu Hasa	UAE	(*670*, *675–678*)
Fath	UAE	(*592*, *679–686*)
Umm Shaif	UAE	(*687–693*)
Upper & Lower Zakum	UAE	(*693–699*)
Al Dabbiya	UAE	(*672*, *700*, *701*)
Sahil	UAE	(*670*, *702*, *703*)
Brent	UK	(*68*, *704–710*)
Forties	UK	(*711–713*)
Ninian	UK	(*68*, *714*)
Piper	UK	(*68*, *715*, *716*)
Atlantis	US	(*717–721*)
Shenzi	US	(*722*)
Kuparuk	US	(*723–726*)
Tahiti	US	(*727–731*)
Great White	US	(*732*, *733*)
Lucius	US	(*734–737*)
Elk Hills	US	(*738*)
Kern River	US	(*739*, *740*)
East Texas	US	(*741–744*)
Lake Washington Field	US	(*745–747*)
Mars	US	(*748–752*)

Midway-Sunset	US	(*753–757*)
Salt Creek	US	(*758*)
WC	US	(*759*)
Thunder Horse	US	(*760–763*)
Wilmington	US	(*60*)
Carito-Mulata	Venezuela	(*764*)
Petromonagas (Cerro Negro)	Venezuela	(*765–768*)
Boscan	Venezuela	(*769–772*)
El Furrial	Venezuela	(*773–777*)
Bitor	Venezuela	(*767*, *778*)
Petro San Felix	Venezuela	(*778*)
Petrocedeno (Sincor)	Venezuela	(*779–781*)
Petropiar (Hamaca)	Venezuela	(*782*, *783*)
Tia Juana (Lago & Tierra)	Venezuela	(*784–795*)
Tomoporo	Venezuela	(*796*)
Orinoco Oil Belt	Venezuela	(*652*, *797–801*)
Leona	Venezuela	(*802–806*)
Lagunillas	Venezuela	(*807–809*)
Tomoporo	Venezuela	(*796*, *807*, *810*, *811*)

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