



Energy-Redefined

Carbon Intensity of Crude Oil in Europe Crude

By Energy-Redefined LLC

For ICCT

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Abbreviations

Abbreviation	Description
API gravity	American Petroleum Institute gravity (measure of relative density of petroleum liquids)
bbl	Barrel(s)
BTU	British thermal unit
CO ₂ eq.	CO ₂ equivalent (includes impact from CO ₂ , nitrous oxide, and methane emissions)
g CO ₂ eq./MJ	Grams CO ₂ equivalent per megajoule
GJ/tonne	Gigajoules per metric tonne
GOR	Gas-to-oil ratio (scf/bbl)
kbpd	Thousand barrels per day
kg CO ₂ eq./bbl	Kilograms CO ₂ equivalent per barrel
kWh	Kilowatt hours
MMbbl/d	Million barrels per day
mmbtu	Million BTUs
mmscf	Million standard cubic feet
mmscfd	Million standard cubic feet per day
NGLs	Natural gas liquids: C ₃ to C ₅ + (propane, butane, pentanes, etc.)
psig	Pounds per square inch gauge
scf	Standard cubic foot
tonne	Metric tonne (1000 kg)

Executive Summary

The International Energy Agency (IEA) predicts that global consumption of crude oil will increase 27% over the next two decades, from 83 million barrels per day (MMbbl/d) in 2009 to 105 MMbbl/d in 2030 (IEA, 2009). Extracting, transporting, and refining crude oil on average account for about 18% of well-to-wheels greenhouse gas (GHG) emissions (U.S. Environmental Protection Agency, 2009; European Commission, 2009). On a global scale, that equates to a very large amount of GHG emissions: about 2.8 billion metric tonnes of CO₂ equivalent per year, equal to about four times the CO₂ emissions of the U.K. from fossil fuels, five times those of Germany, or 50% of all U.S. CO₂ emissions from fossil fuels in 2008. In other words, improvements in the processes of extracting and refining crude oil would mean substantial progress toward reducing overall transportation-sector GHG emissions.

To accurately quantify these emissions from the wellhead to the refinery output gate (henceforth termed extraction-to-refining GHG emissions), we developed emission factors for five components of production: extraction, flaring and venting, fugitive emissions, crude oil transport, and refining. Our goal is to highlight the greatest potential opportunities for reducing or avoiding GHG emissions from oil extraction. The focus is on the European market, as the European Commission is currently considering how best to address extraction-to-refining emissions from petroleum fuels under the Fuel Quality Directive.

Extraction-to-refining greenhouse gas emissions

Europe receives crude oils from a large number of oilfields all over the world. We have modeled the carbon intensity of crude oil from over 3,000 oilfields located in countries that supplied oil to Europe in 2009. Figure E1 is a scatterplot that shows the variation among individual oil fields in extraction-to-refining emissions against the cumulative volume of crude oil production¹. The carbon intensity of crude oils ranges from 4 to 50 grams of CO₂ equivalent per megajoule (g CO₂ eq./MJ)² with an average of 12 g CO₂ eq./MJ. The additional GHG emissions from fuel

¹ This assumes that if a country supplies X% of its oil to Europe, X% of the oil from each individual oilfield in that country is supplied to Europe.

² There are some very small fields that might have values in excess of this, but the volumes of oil coming from such fields will be relatively insignificant.

combustion in motor vehicles are about 73 g CO₂ eq./MJ for both gasoline and diesel. Increasing reliance on the highest-intensity crudes to produce vehicle fuels could result in an increase in total well-to-wheels emissions of up to 45% relative to crudes of average carbon intensity.

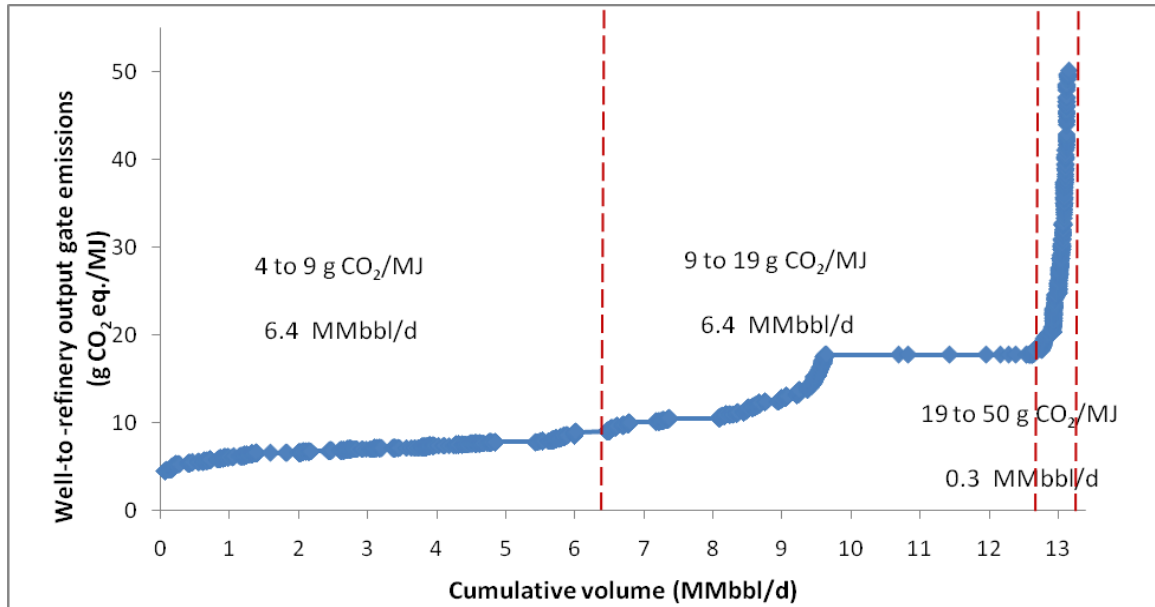


Figure E1. Extraction-to-refining GHG emissions associated with imported crude oil.

In 2009, Europe imported about 13 MMbbl/d of crude oil. For discussion purposes, we divide the imported crude into three broad categories based on extraction-to-refining GHG emissions per energy content of the fuel (Fig. E1). About half of the total (6.4 MMbbl/d) has extraction-to-refining emissions of 4 to 9 g CO₂ eq./MJ, meaning that production is associated with little or no flaring of natural gas, minimal fugitive emissions, high API gravities, and in some cases substantial amounts of oil condensates.³ (The importance of flaring and venting, fugitive emissions, and API gravity are explained below.) Approximately another half (6.4 MMbbl/d) has a carbon intensity range of 9 to 19 g CO₂ eq./MJ. Included in this range are crude oils mainly with high API gravities and/or substantial flaring and fugitive emissions and a lack of oil condensates.

³ Oil condensates are lighter liquid crude oils obtained from reservoirs that mostly contain hydrocarbons in vapor phase. They normally consist of short-chain alkane hydrocarbons. They are easy to clean up and refine.

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For the remaining small volume (0.3 MMbbl/d), there is a sharp rise in carbon intensity, ranging from 19 to 50 g CO₂ eq./MJ, due to either substantial levels of flaring or exploitation of tar sands. This volume represents an attractive target for GHG reductions.

Flaring contributes to GHG emissions in two ways: through the CO₂ released during combustion, and through the presence of methane in unburned gas when combustion is less than 100% efficient. Methane has a global warming potential 25 times that of CO₂.

Production of crude oil from tar sands involves energy-intensive extraction (surface mining or steam-assisted gravity drainage) and upgrading.⁴ (In this study, it is assumed that upgrading of tar sands occurs at the oil field and hence is counted as part of extraction emissions.) Tar sands are one of a group of new fossil fuel feedstocks typically referred to as “unconventional oil”; other feedstocks in this group are shale oil and extra-heavy oil. Producing crude from these sources requires more energy-intensive technologies and processes than from conventional oil sources. The U.S. Energy Information Administration (EIA) currently projects that about 8% (8.9 MMbbl/d) of the world’s oil supply will come from unconventional oil in 2035 (EIA, 2010).

As discussed above, two primary drivers contribute to the highest upstream GHG emissions: the presence of high levels of flaring of natural gas, and unconventional oil such as tar sands. To clarify the ranges of GHG emissions for crude oil extraction involving flaring and tar sands projects, in Figure E2 extraction emissions are broken down into crude oils with flaring, crude oils without flaring, and tar sands. The cumulative volume for each category is divided by the total volume to show normalized cumulative volume in percent (percentage of total imported volumes for each category are also shown in Fig. E2). In general, production of oil from tar sands results in higher GHG emissions than from conventional crude, even from fields that flare natural gas, except when the flared volumes are large in proportion to the oil production (on the right side of the graph).

⁴ Bitumen (tar sands) consists of complex chains of hydrocarbon. It is rich in carbon but deficient in hydrogen. Bitumen is upgraded to remove carbon and add hydrogen to obtain valuable hydrocarbon products. Upgrading results in synthetic crude oil, which can be transported easily via pipeline to refineries.

California's Low Carbon Fuel Standard (LCFS) requires additional reporting for any crude oil with extraction GHG emissions in excess of 15 g CO₂ eq./MJ ('high carbon intensity crude oil', HCICO). Conventional oil produced without flaring falls below that limit.

Figure E2 also shows the volume-weighted average of total extraction-to-refining emission for each category of fuel. The averages are assigned uncertainty ranges by considering the minimum and maximum plausible alternative values of key parameters. It can be seen that although flaring emissions in particular are subject to substantial uncertainty, it can still be asserted with confidence that the average emissions from tar sands projects are higher than the average emissions from projects that flare, which are higher than the average emissions from projects that do not flare.

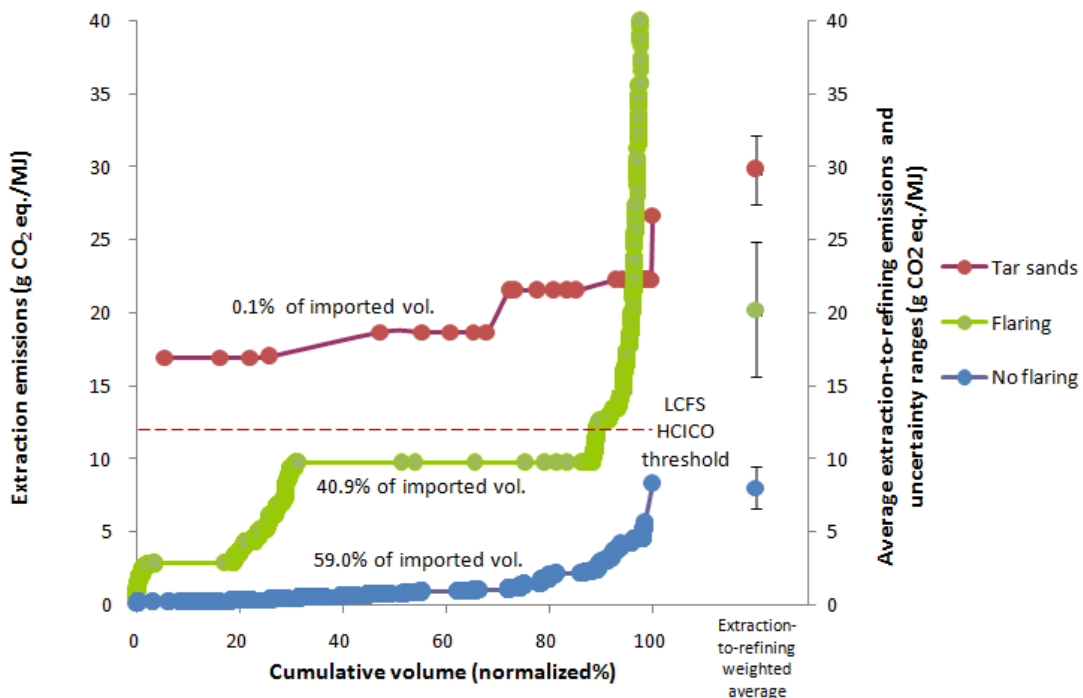


Figure E2. *Left:* Extraction GHG emissions for imported conventional crude oil (with and without flaring) and tar sands. *Right:* Weighted average extraction-to-refining GHG emissions for imported conventional crude oil (with and without flaring) and tar sands, with uncertainty ranges for the average values.

Figure E3 illustrates the results of this analysis with specific cases. The selected oil fields show the wide range in total extraction-to-refining GHG emissions and in the relative contributions from five components of the petroleum life cycle considered in this study. The area of each pie chart in Figure E3 reflects carbon intensity (g CO₂ eq./MJ). Daily production volumes are included in the

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description of each field. The oil fields are selected to represent a range of geographic regions, production levels [42 to 5320 kbpd (thousand barrels per day)], flaring levels, feedstocks, and development types.

Emissions vary by a factor of 5 across the oil fields in Figure E3. In Canada, the difference between the Steepbank and Hibernia fields shows the effect of the additional energy needed to extract tar sands: Steepbank has four times the emissions of Hibernia, a conventional oil field. An oil field with high levels of flaring (e.g., Kupal) can have GHG emissions comparable to or higher than those of tar sands. Countries where flaring is common include Iran and Russia (Buzcu-Guven, Harriss & Hertzmark, 2010). For conventional crudes with minimal flaring, it is the refining step that contributes most to extraction-to-refining GHG emissions. The highest potential GHG reduction opportunities for these crudes are likely to be at the refinery. Note that in this analysis, as explained below, energy use and GHG emissions in refining vary only according to API gravity.

Grouping the oil fields in Figure E3 into low-, medium-, and high-intensity fields illustrates the relationship between key parameters and extraction-to-refining GHG emissions.

Low-intensity fields (6 to 8 g CO₂ eq./MJ) are characterized by little or no flaring or fugitive emissions and high API gravity (crudes with API > 26 are referred to as light crude oils; high API gravity means that refining emissions are lower). Although refining emissions are small for these oil fields, they are still the dominant factor in determining overall extraction-to-refining GHG emissions, as other emissions (including extraction) are even lower.

For medium-intensity oil fields (12 to 15 g CO₂ eq./MJ), extraction-to-refining GHG emissions are larger predominantly because of higher contributions from either flaring or fugitive emissions. For example, Duri has fugitive emissions of 2.7 g CO₂ eq./MJ and flaring emissions of 2.0 g CO₂ eq./MJ. Likewise, Samotlor has flaring emissions of 3.1 g CO₂ eq./MJ. Crude oils produced in Duri and Cantarell are heavy (API gravity < 26) and contribute to relatively higher refinery emissions. Duri uses an energy-intensive steam-flooding technique to extract crude oil. Hence, emissions from extraction are larger than expected.

High-intensity oil fields (22 to 31 g CO₂ eq./MJ) either have higher flaring and venting or produce unconventional crude oil. For example, Kupal and Dacion have higher extraction-to-refining emissions due to substantial flaring and venting. Steepbank, on the other hand, is a tar sands project, which requires more energy for extracting bitumen and upgrading it to synthetic crude oil. Refining emissions for Dacion and Steepbank are higher because they produce heavy crude oils (API gravity < 26).

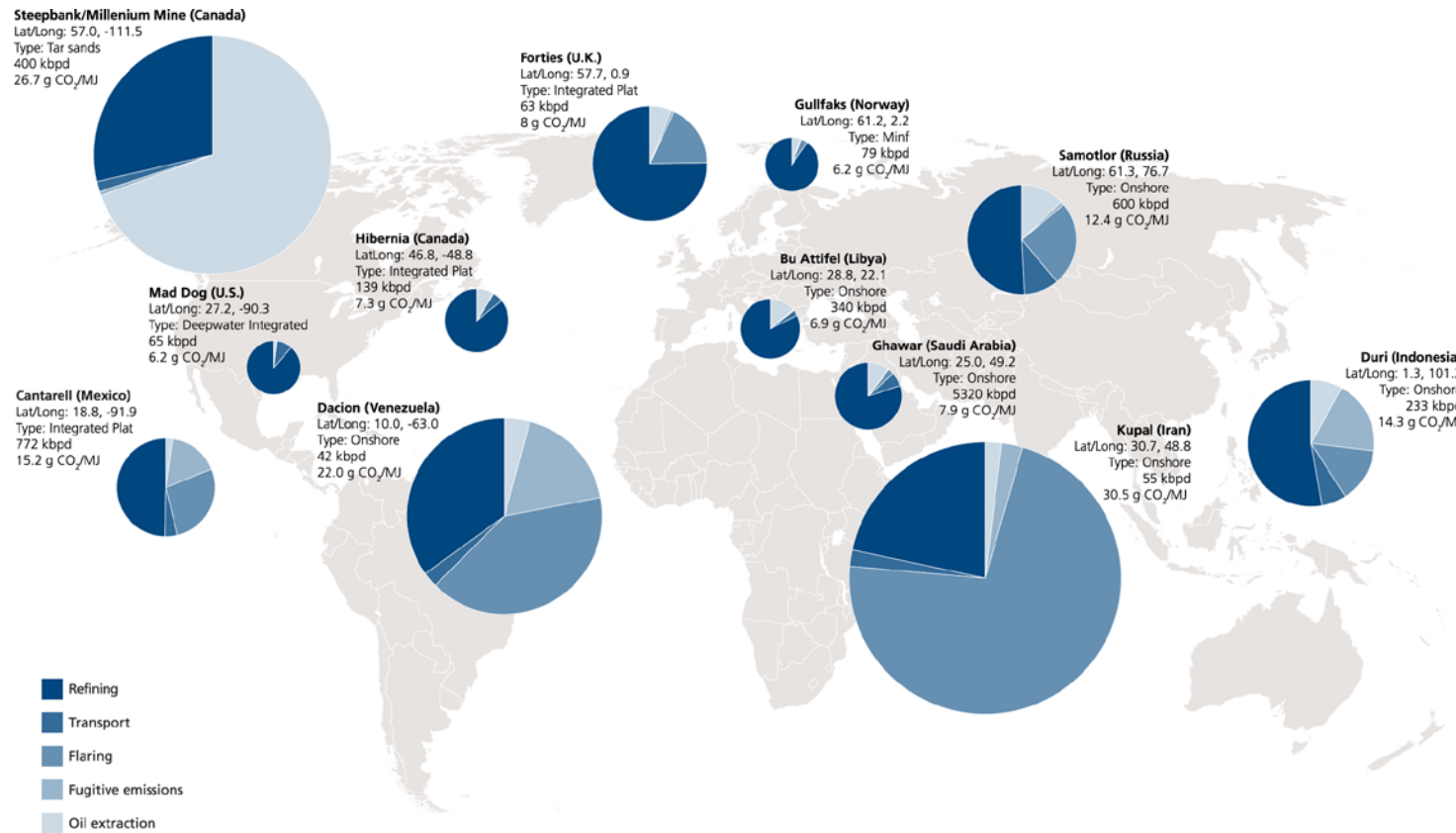


Figure E3. Carbon intensity by contributing components for selected oil fields.

Aggregate GHG emissions are determined by the interplay of various parameters. As Table E1 shows, these vary substantially from one field to another. As a result, any attempt to assign default emissions based on a single characteristic or a limited number of simple characteristics is likely to misspecify emissions substantially in some cases. By providing rigorous and enriched data on oil extraction, fugitive emissions, and flaring for a large number of oil fields (about 3100) that supply to Europe, this study attempts to fill the data gap in life-cycle analysis of petroleum fuels and contribute to the identification of emission reduction opportunities.

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Table E1. Characteristics of crude oil and levels of flaring and fugitive emissions for representative oil fields.

Field and country	Production volume (kbpd)	API gravity	Sulfur (%)	Depth (ft)	Start year	BTU/scf of associated gas	Initial pressure (psig)	Dead crude viscosity (cP)	GOR (scf/bbl)	Fugitive emissions (g CO ₂ /MJ)	Flaring and venting (g CO ₂ /MJ)	Type	Wellhead-to-refinery emissions (g CO ₂ /MJ)
Cantarell, Mexico	772	22	3.7	8,528	1981	1,370	941	8	887	2.5	4.2	Integrated platform drilling	15.2
Mad Dog, USA	65	42	0.8	20,190	2005	1,012	12,141	1.8	322	0.02	0.0	Deepwater integrated	6.2
Steepbank/Millennium Mine, Canada	400	10	1	50	2005	1,267	10	5000	—	0.1	—	Tar sands	26.6
Hibernia, Canada	139	35	0.2	12,500	1984	1,257	7,517	0.8	2,200	0.03	0.0	Integrated platform drilling	7.3
Kupal, Iran	55	32	2	10,500	1970	2,232	2,191	7.3	3,800	0.8	21.9	Onshore	30.5
Ghawar, Saudi Arabia	5,319	34	2.2	6,920	1951	1,255	3,957	1.6	570	0.03	0.2	Onshore	7.9
Dacion, Venezuela	42	20	1.3	6,000	1953	1,794	2,600	11	750	3.9	8.9	Onshore	22.0
Bu Attifel, Libya	340	41	0.04	14,000	1972	1,622	7,209	5.2	2,400	0.04	0.0	Onshore	6.9
Samotlor, Russia	600	34	1.1	5,800	1970	1,456	2,255	3.4	240	0.1	3.1	Onshore	11.8
Duri, Indonesia	233	22	0.2	770	1958	1,362	267	144.1	1,200	2.7	2.0	Onshore	14.3
Forties, U.K.	63	37	0.3	7,000	1975	2,851	3,128	2.2	400	0.1	1.4	Integrated platform drilling	8.0
Gullfaks, Norway	79	41	0.4	5,709	1987	1,557	2,551	2	700	0.04	0.2	Minimum facility	6.2

Note: This study did not consider sulfur content for determining refinery emissions, although it does affect energy use in refining.

Data sources (not an exhaustive list): API gravity, sulfur content, viscosity: PennWell, Institute of Energy, Society of Petroleum Engineers, U.S. Energy Information Administration, *Petroleum Intelligence Weekly*, U.S. Geological Survey (USGS). Depth, pressure: PennWell, USGS, Institute of Energy, Society of Petroleum Engineers. Production: U.K. Department of Energy, U.S. Minerals Management Service, Norwegian Petroleum Development/Ministry of Energy, PennWell, company reports, various other government organizations. Flaring: GGFR, NOAA, Energy-Redefined LLC, various company sustainability reports. Fugitive emissions: CAPP, API, various company sustainability reports. Start year and GOR: PennWell, company reports, conference proceedings, various geological societies. Type of development/feedstock: PennWell, Norwegian Petroleum Development/Ministry of Energy, company reports, Society of Petroleum Engineers, conference proceedings.

Major Crude Oil Exporters to Europe

Crude oils used in Europe come from many countries and all major geographic regions. As Figure E4 illustrates, Russia is by far the largest exporter of oil to Europe. Russian facilities flare off a substantial amount of natural gas (46 billion m³ in 2009) (Buzcu-Guven, Harriss & Hertzmark, 2010); reducing that volume represents an important opportunity for reducing life-cycle GHG emissions of petroleum fuels in Europe. Similar opportunities also exist in other top-10 exporting countries, such as Libya, Nigeria, and Kazakhstan.

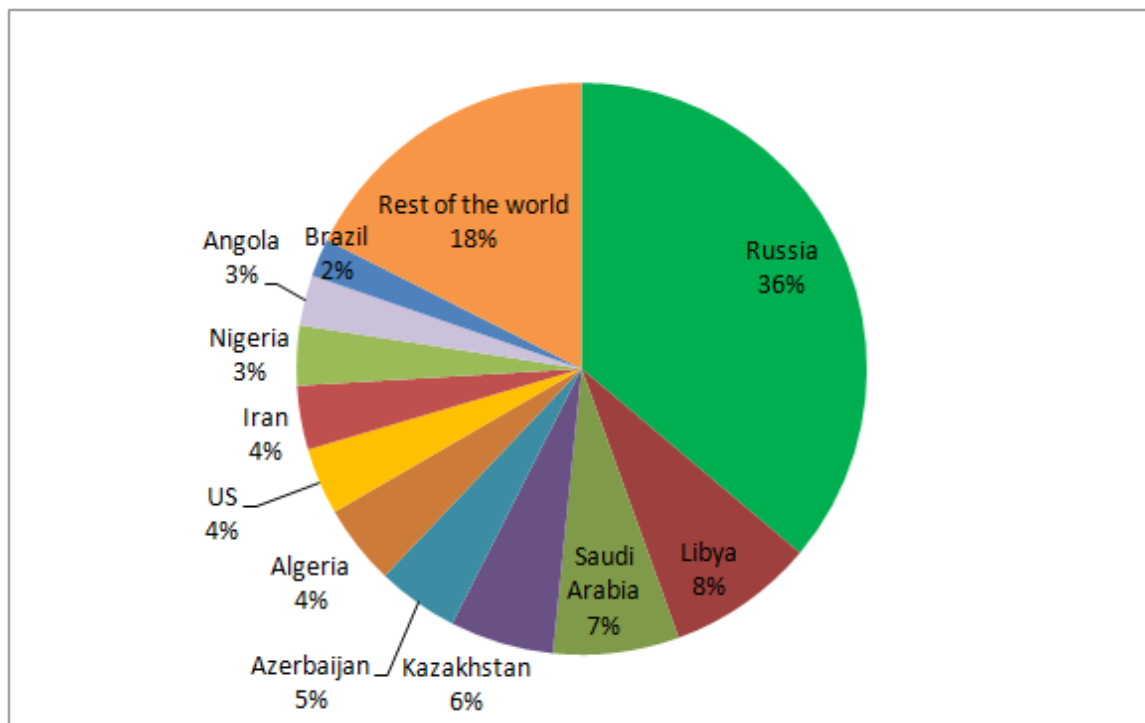


Figure E4. Major crude oil exporters to Europe in 2010.

Methodology

To calculate extraction-to-refining GHG emissions, we conducted a life-cycle assessment (LCA) on approximately 3100 oil fields in countries that supply oil to Europe, using the global database of more than 6000 individual oil fields compiled by Energy-Redefined LLC. This study developed GHG emission factors for five elements of extraction-to-refining analysis: crude oil extraction, flaring and venting, fugitive emissions, crude oil transport, and refining. The central aspect of the analysis is to identify the parameters (Table E2) that influence GHG emissions throughout the petroleum life cycle and use them in estimating emission factors for each oil field, based on 2009 data.

The Energy-Redefined LLC oil field database was compiled from publicly available sources and through working relationships with the oil and gas industry. Where data were missing, Energy-Redefined LLC made estimates based on expert judgment and calculations and calibrated them with known data and available studies for verification.

Key parameters that affect life-cycle GHG emissions from different components of petroleum fuel are briefly summarized below.

Crude Oil Extraction

GHG emissions in the extraction phase are determined by the interactions of eight main parameters: age of oil field, gas-to-oil ratio, reservoir depth, pressure, viscosity, American Petroleum Institute (API) gravity (a measure of how “light” or “heavy” a crude is relative to water), type of feedstock (e.g., tar sands, conventional crude), and development type [onshore, offshore, surface mining, steam-assisted gravity drainage (SAGD)]. This study does not consider coal-to-liquid and gas-to-liquid methods or oil shale.

The ratio of the volume of gas in solution to the volume of crude oil at standard conditions is the gas-to-oil ratio (GOR). Higher values of GOR lead to higher production of natural gas. The gas produced can be used in extraction for meeting onsite energy needs, exported, and/or flared and vented. If it is flared and vented, it can substantially increase life-cycle GHG emissions. A high GOR can also correspond to production of substantial amounts of oil condensates.

The age of an oil field influences GHG emissions because as fields mature, oil production declines; energy-intensive techniques such as water or gas injection must then be used to extend production levels, resulting in increased GHG emissions.

Heavier crude oils (low API gravity) require more energy to extract, transport, and refine. Crude oils with higher viscosity require more energy for pumping. Reservoir depth and pressure also affect energy use in extraction. With a decrease in depth, friction losses increase in the drill pipe. As fields mature, the initial pressures tend to decline in the absence of intervention. Maintenance techniques such as water injection are required to maintain the initial pressure. These pumping or compression techniques involve pumping fluids back into the reservoir to extract crude oil. If the initial reservoir pressure is high, the energy required for maintaining the pressure will also be high.

Different amounts of energy are required to extract and upgrade crude oil from different types of feedstock. Tar sands and conventional oil require completely different extraction technologies. Among tar sands, differences exist between surface mining and in situ methods such as SAGD, resulting in different GHG emissions.

In addition, the type of oil field development [onshore/offshore, surface mining, thermally enhanced oil recovery (TEOR), etc.] determines the infrastructure required. Differences in infrastructure also influence energy requirements affecting GHG emissions during extraction of crude oil. For example, TEOR requires more energy than any other conventional form of offshore or onshore crude oil extraction.

Flaring and Venting

Flaring and venting are an important source of GHG emissions from oil fields. When crude oil is extracted, gas dissolved in crude oil is released, which can be used for meeting energy needs in extraction, captured and sold as product, or flared and vented. Flaring refers to disposal of associated gas produced during extraction through burning. Venting refers to intentional releases of gas and the release of uncombusted gas in flaring (the combustion efficiency of flaring is not 100%, so some methane is left in the exhaust gas).

In this study, the volume of gas flared is derived from GOR, energy use in the field, and the quantity of gas exported. Satellite data (e.g., from NOAA) and country-level emission factors [Global Gas Flaring Reduction (GGFR); World Bank, n.d.] were also used. Besides the volume of gas flared, gas specifications are important in determining GHG emissions from flaring. In general, gas with higher energy content per unit volume produces more GHG emissions when flared.

One can be reasonably confident about which oil fields are flaring and which are not from satellite data and the lack or presence of infrastructure. However, uncertainties exist with regard to the volumes of gas flared and vented.

Fugitive Emissions

Fugitive emissions represent unintentional or uncontrollable releases of gas—for example, from valves and mechanical seals. It is difficult to measure fugitive emissions. The usual practice is to base such measurements on emission factors suggested by the Canadian Association of Petroleum Producers (CAPP), the U.S. Environmental Protection Agency (EPA), and the International Association of Oil and Gas Producers (OGP). In this study, fugitive emissions were determined on the basis of CAPP emission factors (CAPP, 2003) for equipment fittings such as seals, valves, and flanges.

The use of such emission factors can result in significant errors. The alternative is to use leak detection methods, such as acoustic sensors and hyperspectral imaging, and optical methods such as tunable diode laser absorption spectroscopy and laser-induced fluorescence. The costs of monitoring and verification using these techniques can be high.

Table E2. Parameters affecting extraction-to-refining GHG emissions.

LCA components	Parameters	Underlying data
Crude oil extraction (8 parameters)	GOR, API gravity, viscosity, age of field, depth, pressure, type of development (in situ, surface mining, onshore/offshore), type of feedstock	Publicly available literature (industry data and government reports), PennWell data, consultant data (Energy-Redefined LLC)
Flaring and venting (5 parameters)	GOR, gas specifications, age of field, infrastructure for gas capture, infrastructure for export	Oil company reports, government reports, satellite data from NOAA, World Bank/GGFR country-level emission factors for flaring, consultant data (Energy-Redefined LLC)
Fugitive emissions (non-intentional) (2 parameters)	Type of development, equipment components	CAPP emission factors for fugitive emissions
Crude oil transport (3 parameters)	Distance, API gravity, mode of transport	PennWell data for API, PortWorld for distance, GREET for transportation emission factors
Refining (1 parameter)	API gravity	PennWell data, publicly available literature, consultant data (Energy-Redefined LLC)

Transport

GHG emissions from crude oil transport to a refinery are a function of distance, API gravity, and mode of transport. API data were taken from PennWell. Distances between oil fields and refineries were determined using PortWorld. Emission factors for a given mode of transport were taken from GREET (Wang, 2010).

Refining

GHG emissions from refining are a function of API gravity, sulfur content, and type of refinery. In general, heavy crudes (low API gravity) require more energy to process than light crudes. In this study, we applied the relationship devised by Keesom, Unnasch, and Moretta (2009), calibrated to European refineries, to estimate

GHG emissions. The relationship between API gravity and energy consumption is not linear for API gravities above 45. GHG emissions also vary from one refinery type to another depending on the level of complexity and type of refined products produced. As a simplification, this study assumes that crude oils are refined in a notional refinery where GHG emissions are determined entirely by API gravity. The impact of sulfur content was not considered in this study.

Uncertainties in the Assessment

There are uncertainties involved in undertaking a carbon intensity assessment such as this. For instance, some of the most important emissions sources, such as flaring and fugitive emissions, are not fully monitored by oil companies, and where they are, the data may not be publicly available. Even where gas flaring and fugitive emissions are monitored, the measurement tools currently available are subject to a degree of inaccuracy determined by the physical characteristics of the measurement system. Flare efficiency may also be subject to factors beyond the control of oil companies, such as local wind conditions.

To test the robustness of the results, we undertook a sensitivity analysis in which key input parameters were varied for three typical cases (low-, medium-, and high-intensity fields). Emissions from high-intensity fields that flare are inevitably particularly sensitive to the parameters that determine flaring emissions. For example, when we used the Canadian model of a default flaring value instead of estimating flaring on the basis of data about the oil fields, the intensity of the high-intensity case was reduced by nearly 30%. Varying other parameters resulted in changes of less than 10%.

Opportunities for GHG Reduction

This assessment demonstrates the use of physical characteristics of oil fields in making detailed estimates of the carbon intensity of different crudes. These estimates are based on processes and process efficiencies, and hence this report points to opportunities for the biggest gains in reducing or avoiding GHG emissions from oil extraction by improving practices.

The greatest opportunities are in the highest-intensity crudes and involve emissions associated with unconventional oil extraction and flaring. Flaring is primarily an infrastructure problem; incentives to reduce flaring and fugitive emissions would enhance the value to oil companies of developing infrastructure and markets for excess gas. Operators could optimize flare tip efficiency to reduce methane emissions, move to reinjection of associated gas, or adopt capture and underground storage of CO₂ (Bergerson & Keith, 2010). Extraction of unconventional oil (e.g., tar sands) with current technologies is highly energy-intensive. However, the extraction emissions of unconventional oil could be reduced by limiting its exploitation, by improving energy and carbon

efficiencies (such as using energy inputs with low carbon intensity) in extraction processes, or by implementing carbon capture and storage.

Energy-inefficient processes are costly not only to the environment but to the companies engaged in oil extraction. Requiring better measurement of energy use and carbon emissions is an important first step in reducing energy consumption. Measurement, management, and optimization of oil fields, including GHG emissions, can become an essential component in making better decisions, providing better results, and creating more opportunities.

Older conventional oil fields often depend on old technology—one of the reasons that the Energy-Redefined LLC model predicts high emissions from these projects. For such oil fields, GHG emissions can be reduced by using efficient power/motor drives, integrated energy management approaches, and oil and gas field optimization. Old pumps may be less efficient; they may also be operating outside their optimal range because of turn-down (the ratio of the present capacity of a project to its design capacity). More modern equipment would in many cases deliver substantial carbon reductions. A similar situation can exist in countries such as Russia and Indonesia where locally built power generation equipment is far less efficient than the best alternatives on the market internationally; the gap in performance could be as wide as 20 to 35% in efficiency terms.

As with any industrial process, improvements in efficiency often can result from better housekeeping and use of the most modern technologies. The analysis presented here provides a valuable indicator of the types of oil fields—and, in some cases, specific fields—where prioritizing efficiency improvements or flaring and fugitive emission reductions could deliver the largest benefits.

1. Introduction

Petroleum fuels are predominantly used in the transportation sector, making it a substantial contributor of greenhouse gas (GHG) emissions. In response to the need to mitigate climate change and improve energy security, governments around the globe have started to encourage or require the use of low-carbon fuels. Some prominent examples include the Renewable Energy Directive (RED) and Fuel Quality Directive (FQD) in Europe and the Renewable Fuel Standard-2 (RFS2) and California's Low Carbon Fuel Standard (LCFS) in the United States. FQD requires a reduction of 6% in the carbon intensity of transportation fuels by 2020. California's LCFS is even more aggressive, requiring a reduction of 10% by 2020.

Without an accurate estimate of current GHG emissions from petroleum fuels, the true benefits of low-carbon fuels cannot be measured. Moreover, an accurate estimate would make it easier to discourage further increases in the carbon intensity of petroleum fuels, such as would result from the increased use of tar sands. Europe is developing a methodology for estimating the GHG emissions of petroleum fuels under the FQD, which will be recommended for adoption by the end of 2010. California's LCFS has already established the baseline emissions for gasoline and diesel derived from the 2006 California crude mix. It also has provisions for identifying crudes with high carbon intensity and regulating them.

In this regulatory context, many engineers and managers are now being asked to assess their companies' annual contributions to global warming. This is performed by calculating the GHG emissions, or CO₂ equivalent emissions, including the emissions associated with energy use. However, although conceptually relatively simple, these calculations can be time-consuming and tedious, and errors may occur because of the many unit conversions that are required and the difficulty in obtaining certain types of data. Such calculations also tell us nothing about the future carbon footprints of these assets, even indicatively. The data also reside in many operating units of different companies, which report their emissions in different ways.

This lack of consistency and lack of transparency means that little is known about the emissions from many of the world's oil fields. Of course, there have been studies on individual operating projects and studies on generic fields to estimate emissions (Alberta Chamber of Resources, 2004, p. 2; Brandt, 2008; Brandt & Farrell, 2007; National Energy Technology Laboratory, 2009). We have drawn on some of this work in constructing our models. But no previous study has compared the emissions intensities of individual fields throughout the world. This study provides this level of detail, field by field, albeit with some uncertainties in the data and assumptions used.

For each oil field, we constructed a multidimensional database of attributes such as type of field development and reservoir characteristics. These data enabled us to perform an engineering-based estimation of the energy used, and therefore the emissions produced, by each field. To check and calibrate our data, we compared these

results with other studies and some known data points from operator data. In addition, we have estimated flaring emissions by field for the entire world. This bottom-up approach compares well with data aggregated at the country level.

In estimating these emissions, we have taken an approach that is field-centric; that is, we considered the marginal effect of producing, transporting, and refining specific crudes from the wellhead on a field-by-field basis.

Although we have modeled the individual fields in detail, our approach to refining is more simplified. We have used a relationship derived by other authors (Keesom, Unnasch, & Moretta, 2009; Wang, Lee, & Molburg, 2004) and modified this to reflect the processing energy requirements of European refineries. This relationship estimates energy use as a linear function of crude API gravity.

In addition, we have assumed in this model that each crude/gas stream acts independently. In practice, crude/gas streams can be blended and presented to the process plant. It may be that the combination of the crude/gas stream does not produce the same emissions profile as the sum of the parts. It would be possible to perform this calculation with more granular data, but this would add complexity to an already complex model.

1.1 Why This Approach?

- Many papers in the public domain report generalized data (e.g., heavy-oil fields are 6 to 20 times as energy-intensive as conventional crudes). The existing papers are historical or backward-looking.
- Companies report data on an aggregated basis, not field-by-field, occasionally broken out by category (e.g., by country).
- Although company data are available, it is not necessarily clear what the data represent, and they are not consistently reported.⁵

Energy-Redefined LLC's objective in building the approach presented herein is to:

⁵ Operators report their production, carbon emissions, and other outputs in a variety of different ways. Some operators report on an operated basis (i.e., 100% of what they operate, whether they own it or not); others report on an equity basis (i.e., only what they own). Some operators use entitlement barrels (i.e., what they pick up at the export terminal), whereas others use net barrels (i.e., their share of actual production).

- Consider each individual oil field asset from the bottom up, as a means to calculate probable crude intensities from the wellhead to the output of the refinery.
- Provide more granularity to the emissions data already being discussed in the public domain. (For example, in our analysis we have found that combusted gas fields can have an emission factor ranging from 2 to 7 kg/m³, depending on gas specification. By contrast, companies typically use a default value—e.g., 2.3 kg/m³ in Canada—rather than a more accurate reflection of the gas actually combusted.)
- Estimate emissions on a consistent basis.
- Enable us to dig deeper into the aggregate numbers to understand the drivers of emissions now and in the future.
- Provide views on future trends, particularly with regard to European imports of these crudes.

1.2 Emissions from Ancillary Sources Associated with Oil Production

Our model does not currently include emissions associated with

- Construction activity
- Freight or personal transportation (e.g., helicopters, ground vehicles)
- Buildings
- Well workovers and testing
- Exploration and seismic activity
- Changes in land use

Prior work on specific case studies indicates that consideration of such emissions might add 5 to 10% to the numbers presented herein. Below, we discuss in more detail the specific assumptions used in our methodology.

2. Methodology

To provide views on carbon footprints associated with upstream⁶ and downstream production, Energy-Redefined LLC has used a proprietary model that estimates the impact of individual crudes on carbon emissions across the value chain. It incorporates data on field attributes such as API gravity, viscosity, reservoir pressure, and transportation distance. It does the following:

- Uses engineering-based calculations to estimate energy use for different field types with different depths and pressures
- Estimates flaring at the field, based on gas-to-oil ratio (GOR) data and energy use at the field
- Calculates venting and flaring according to field type
- Takes into account the maturity of the field
- Estimates emissions from the above sources

A number of documents currently in the public domain—published by oil companies, governments, academic institutions, and other agencies—provide estimates of the carbon footprints of oil field operations. These are historical in nature, reporting estimated emissions and providing aggregate views. In many cases they focus on one field or are more generic. The methodologies and reporting standards used can vary greatly. They do not provide:

- A field-by-field analysis for the whole world
- A consistent view of carbon emissions
- Future views of the footprints, recognizing attributes such as maturity of production and changes in key variables such as GOR⁷

For this reason, Energy-Redefined LLC created a model that attempts on a consistent basis to estimate carbon footprints across the value chain from the bottom up, using data from individual oil fields. We have used this

⁶ Upstream emissions include emissions from extraction, flaring, and fugitive emissions.

⁷ GOR is a measure of the gas produced at the well; it is not simply the gas reserves divided by the oil reserves.

model to estimate emissions for some 6000 oil fields representing some 80 to 85 MMbbl/d (80,000 to 85,000 kbpd) in 2010.⁸ We have filtered the output of this data set to produce a European view.

The model estimates the marginal effect of each crude through the value chain, starting from the wellhead through various intermediate steps (flaring, transportation to the refinery, etc.) and ending with its impact at the refinery. Note that our analysis stops at the refinery output fence. That is, we do not assess emissions for distribution of the end products or their final combustion. We have not attempted to apportion crudes to particular refineries,⁹ but we currently assume that the crudes will be transported to Europe.¹⁰ Our estimates of refinery processing requirements and their associated carbon footprint are based on a notional refinery¹¹ using a linear relationship between API gravity and energy use; therefore, heavier crudes require greater processing energy in our model. The end-product yields were derived from European refining data.

Carbon emission factors (kg/bbl or g/MJ) can vary greatly according to field size and maturity.¹² They depend on many parameters, interlinked in many parts of the chain (Fig. 1).

⁸ Once filtered to take account of European crude imports, this volume drops to 13,000 to 14,000 kbpd. This does not include crude oils produced within Europe that are refined in Europe.

⁹ Refiners optimize their crude slate on a continuous basis. It would be difficult to perform this task with any accuracy, as this is commercially sensitive information. Refiners also buy crudes opportunistically.

¹⁰ In practice, some of the crudes will be transported to a refinery only 100 miles away, whereas some might be exported thousands of miles to other refineries. In the case of the European analysis, we have used transportation factors that reflect transport of crudes to Europe from the country of origin.

¹¹ Actual refineries may import a variety of equity and non-equity crudes. We are not attempting here to calculate the actual refinery emissions of any particular refinery, but rather the marginal effect of refining a particular crude.

¹² Depending on the BTU content of the gas produced, final emissions can vary by factor of 3:1 in the extreme. The energy required for tar sands production can be as high as 5 to 20 times that required for a conventional crude.

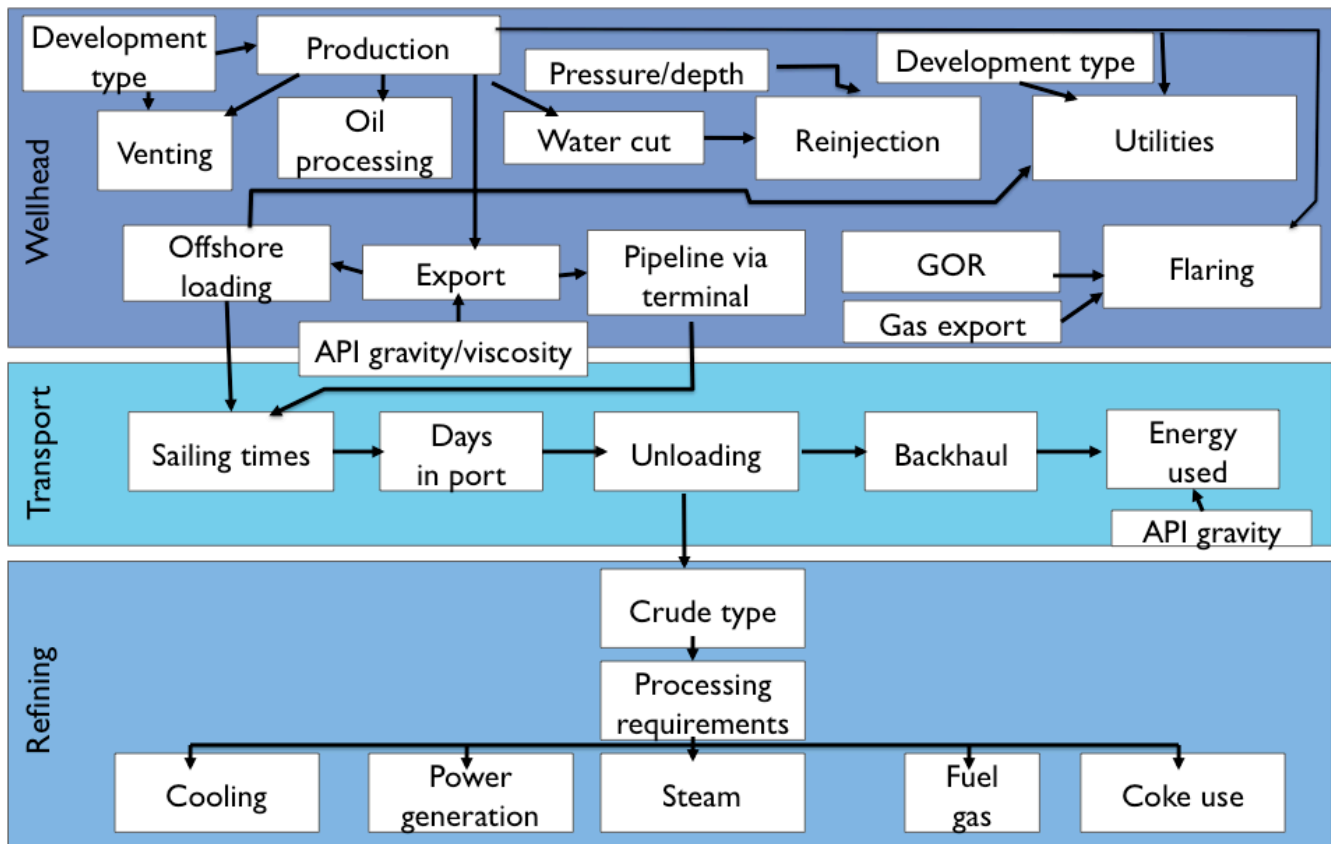


Figure 1. Elements involved in estimating carbon emissions for crude oil. Note that this figure does not include every link and element.

We believe that a good understanding of these elements is essential to estimating carbon emissions both at the field and within the overall value chain, especially through time. Our model attempts to estimate these variations by accounting for energy use at the field and the refinery plants. Because this energy use varies according to oil and gas specifications, we compiled an extensive database of these specifications to drive our model.

Some of the standard reporting methodologies, such as those used by Canadian producers, propose the use of standard factors to estimate oil and gas flaring, venting, and fugitive emissions. Our methodology could therefore depart from current reported numbers; however, it appears to deliver results in the right ballpark relative to other data.

Our approach to compiling these data and calculations was a multifaceted one, drawing on public-domain publications as well as our own experience and data (including proprietary engineering-based models) to estimate energy use at a given field or processing plant. Table 1 summarizes the data sources and challenges involved in determining the five main components of GHG emissions from the wellhead to the refinery output gate. Descriptions of these key parameters and their significance are provided below.

Table 1. Data source summary.

Value chain element	Key parameters	Data sources	Data challenges
Extraction	<ul style="list-style-type: none"> • Age of field • Depth • Initial reservoir pressure • Viscosity • GOR • API gravity • Type of development/feedstock 	Oil company reports, government reports, PennWell, Institute of Energy, Energy-Redefined LLC database for production energy	<ul style="list-style-type: none"> • Confidential oil company data • Not in one place • Some data must be purchased for substantial fees, with restrictions • Government ownership/secretcy • Reporting of data on varied basis • Frequent errors in data quality control
Flaring	<ul style="list-style-type: none"> • Gas-to-oil ratio (GOR) • Energy use at field • Gas specifications • Infrastructure for gas transport • Age of field 	GGFR country-average emission factors, Energy-Redefined LLC data, NOAA satellite data	<ul style="list-style-type: none"> • No complete set of field-by-field data • Inaccuracy in measurements ($\pm 20\%$) • Not measured frequently
Fugitive emissions	<ul style="list-style-type: none"> • Type of development • Number of components 	Oil company and government reports, CAPP/OGP/EPA emission factors, Energy-Redefined LLC field estimates from factors	<ul style="list-style-type: none"> • No current detailed data for fugitive emissions by field • Inaccuracy in measurements ($\pm 300\%$) • Not measured frequently • Confidential data
Transport	<ul style="list-style-type: none"> • Distance • API gravity 	PennWell, portworld.com, GREET	<ul style="list-style-type: none"> • Emissions not reported by tanker (but can be calculated)
Refining	<ul style="list-style-type: none"> • API gravity • Sulfur content • Type of refinery 	Oil company data, PennWell, publicly available literature	<ul style="list-style-type: none"> • Confidential data • Actual refinery setup and operation can vary • Some data are estimates based on assumptions

Crude Oil Extraction

GHG emissions in the extraction phase are determined by the interaction of eight main parameters: age of oil field, gas-to-oil ratio, reservoir depth, pressure, viscosity, American Petroleum Institute (API) gravity (a measure of how “light” or “heavy” the oil is relative to water), type of feedstock (e.g., tar sands vs. conventional crude), and development type [e.g., onshore, offshore, surface mining, steam-assisted gravity drainage (SAGD)]. This study does not consider coal-to-liquid and gas-to-liquid methods and oil shale.

The gas-to-oil ratio (GOR) is the ratio of the volume of gas in solution to the volume of crude oil at standard conditions. Higher values of GOR lead to higher production of natural gas. The gas produced can be used in extraction for meeting onsite energy needs, exported, and/or flared and vented. If it is flared and vented, it can substantially increase life-cycle GHG emissions. High values of GOR are also relevant for oil fields that produce substantial amounts of oil condensates.

The age of an oil field plays an important role in GHG emissions because oil production declines as fields mature, requiring the use of energy-intensive extraction techniques such as water and gas injection. These efforts to extend previous production levels result in increased GHG emissions.

Heavier crude oils (low API gravity) require more energy to extract, transport, and refine. GHG emissions of heavier crude oil are larger than those of lighter crude oil (higher API gravity). Crude oils with higher viscosity require more energy for pumping.

Reservoir depth and pressure also affect energy use in extraction. With a decrease in depth, friction losses increase in the drill pipe. As fields mature, the initial pressures tend to decline in the absence of intervention. Maintenance techniques such as water injection are required to maintain the initial pressure. These pumping or compression techniques involve pumping fluids back into the reservoir to extract crude oil. If the initial reservoir pressure is high, the energy required to maintain the pressure will also be high.

Different amounts of energy are required to extract and upgrade crude oil from different types of feedstock (e.g., tar sands, oil shale, conventional oil). Tar sands require extraction technologies completely different from those needed for conventional oil. Even among tar sands, differences exist between surface mining and in situ methods such as SAGD, resulting in different GHG emissions.

In addition, the type of oil field development—onshore, offshore, surface mining, thermally enhanced oil recovery (TEOR), etc.—determines the nature of the infrastructure required and its associated energy use, which affects GHG emissions during extraction of crude oil. TEOR requires more energy than any other conventional form of offshore or onshore crude oil extraction.

Flaring and Venting

Flaring and venting are an important source of GHG emissions from oil fields. Flaring refers to disposal of associated gas produced during extraction through burning. Venting refers to intentional releases of gas, including the amount of gas unburned in flaring. The combustion efficiency of flaring is less than 100%, which implies that there is some methane left in the flared gas.

When crude oil is extracted, gas dissolved in crude oil is released, which can be used for meeting energy needs in extraction, exported, or flared/vented. The volume of gas flared is derived from GOR, energy use in the field, and the quantity of gas exported. Satellite data (e.g., from NOAA) and country-level emission factors (GGFR, World Bank) were used to determine the volume of gas flared in this study. Besides the volume of gas flared, gas specifications are important in determining GHG emissions from flaring. In general, gas with higher energy content per unit volume produces more GHG emissions when flared. In Russia, for example, gas from associated oil fields contains on average 60% NGLs. It therefore emits at least 50% more CO₂ than the same volume of gas in the United States, assuming that all the gas is burned. Energy-Redefined LLC therefore felt that it was imperative to capture these effects, especially if flaring is an important determinant of emission factors.

One can be reasonably confident about which oil fields are flaring and which are not from satellite data and the lack or presence of infrastructure. Uncertainties exist with regard to the volumes of gas flared and vented, including fugitive emissions. This is particularly true for fugitive emissions, which are mainly estimated on the basis of emission factors.

Fugitive Emissions

Fugitive emissions—unintentional or uncontrollable releases of gas, such as from valves and mechanical seals—have proven difficult to measure. The usual practice is to use emission factors suggested by the Canadian Association of Petroleum Producers (CAPP), EPA, and the International Association of Oil and Gas Producers (OGP). In this study, fugitive emissions were determined using CAPP emission factors (CAPP, 2003) for equipment fittings such as seals, valves, and flanges.

The use of emission factors can lead to significant errors. The alternative is to use leak detection methods such as acoustic sensors and hyperspectral imaging, and/or optical methods such as tunable diode laser absorption spectroscopy and laser-induced fluorescence. The costs of monitoring and verification using these techniques can be high.

Transport

GHG emissions from crude oil transport to a refinery are a function of distance, API gravity, and mode of transport. API data were taken from PennWell. Distances between oil fields and refineries were determined using PortWorld. Emission factors for a given mode of transport were taken from GREET (Wang, 2010).

Refining

GHG emissions from refining are a function of API gravity, sulfur content, and type of refinery. In general, heavy crudes (low API gravity) require more energy to process than light crudes. In this study, we applied the relationship devised by Keesom et al. (2009), calibrated to European refineries, to estimate GHG emissions. The relationship between API gravity and energy consumption is not linear for API gravities above 45. GHG emissions also vary from one refinery type to another depending on the level of complexity and type of refined products produced. As a simplification, this study assumes that crude oils are refined in a notional refinery where GHG emissions are determined entirely by API gravity. The impact of sulfur content was not considered in this study.

For the purpose of illustration, we have provided values for these key parameters for several oil fields in Table 2.

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Table 2. Characteristics of crude oil and levels of flaring and fugitive emissions for representative oil fields.

Field and country	Production volume (kbpd)	API gravity	Sulfur (%)	Depth (ft)	Start year	BTU/scf of associated gas	Initial pressure (psig)	Dead crude viscosity (cP)	GOR (scf/bbl)	Fugitive emissions (g CO ₂ /MJ)	Flaring and venting (g CO ₂ /MJ)	Type	Wellhead-to-refinery emissions (g CO ₂ /MJ)
Cantarell, Mexico	772	21.5	3.7	8,528	1981	1,370	941	8	887	2.5	4.2	Integrated platform drilling	15.2
Mad Dog, USA	65	42	0.8	20,190	2005	1,012	12,141	1.8	322	0.02	0.0	Deepwater integrated	6.2
Steepbank/Millennium Mine, Canada	400	10	1	50	2005	1,267	10	5000	—	0.1	—	Tar sands	26.6
Hibernia, Canada	139	35	0.2	12,500	1984	1,257	7,517	0.8	2,200	0.03	0.0	Integrated platform drilling	7.3
Kupal, Iran	55	32	2	10,500	1970	2,232	2,191	7.3	3,800	0.8	21.9	Onshore	30.5
Ghawar, Saudi Arabia	5,319	34	2.2	6,920	1951	1,255	3,957	1.6	570	0.03	0.2	Onshore	7.9
Dacion, Venezuela	42	20	1.3	6,000	1953	1,794	2,600	11	750	3.9	8.9	Onshore	22.0
Bu Attifel, Libya	340	40.7	0.04	14,000	1972	1,622	7,209	5.2	2,400	0.04	0.0	Onshore	6.9
Samotlor, Russia	600	34.2	1.1	5,800	1970	1,456	2,255	3.4	240	0.1	3.1	Onshore	11.8
Duri, Indonesia	233	22	0.2	770	1958	1,362	267	144.1	1,200	2.7	2.0	Onshore	14.3
Forties, U.K.	63	37	0.3	7,000	1975	2,851	3,128	2.2	400	0.1	1.4	Integrated platform drilling	8.0
Gullfaks, Norway	79	41	0.4	5,709	1987	1,557	2,551	2	700	0.04	0.2	Minimum facility	6.2

Note: This study did not consider sulfur content for determining refinery emissions, although it does affect energy use in refining.

Data sources (not an exhaustive list): API gravity, sulfur content, viscosity: PennWell, Institute of Energy, Society of Petroleum Engineers, U.S. Energy Information Administration, *Petroleum Intelligence Weekly*, U.S. Geological Survey (USGS). Depth, pressure: PennWell, USGS, Institute of Energy, Society of Petroleum Engineers. Production: U.K. Department of Energy, U.S. Minerals Management Service, Norwegian Petroleum Development/Ministry of Energy, PennWell, company reports, various other government organizations. Flaring: GGFR, NOAA, Energy-Redefined LLC, various company sustainability reports. Fugitive emissions: CAPP, API, various company sustainability reports. Start year and GOR: PennWell, company reports, conference proceedings, various geological societies. Type of development/feedstock: PennWell, Norwegian Petroleum Development/Ministry of Energy, company reports, Society of Petroleum Engineers, conference proceedings.

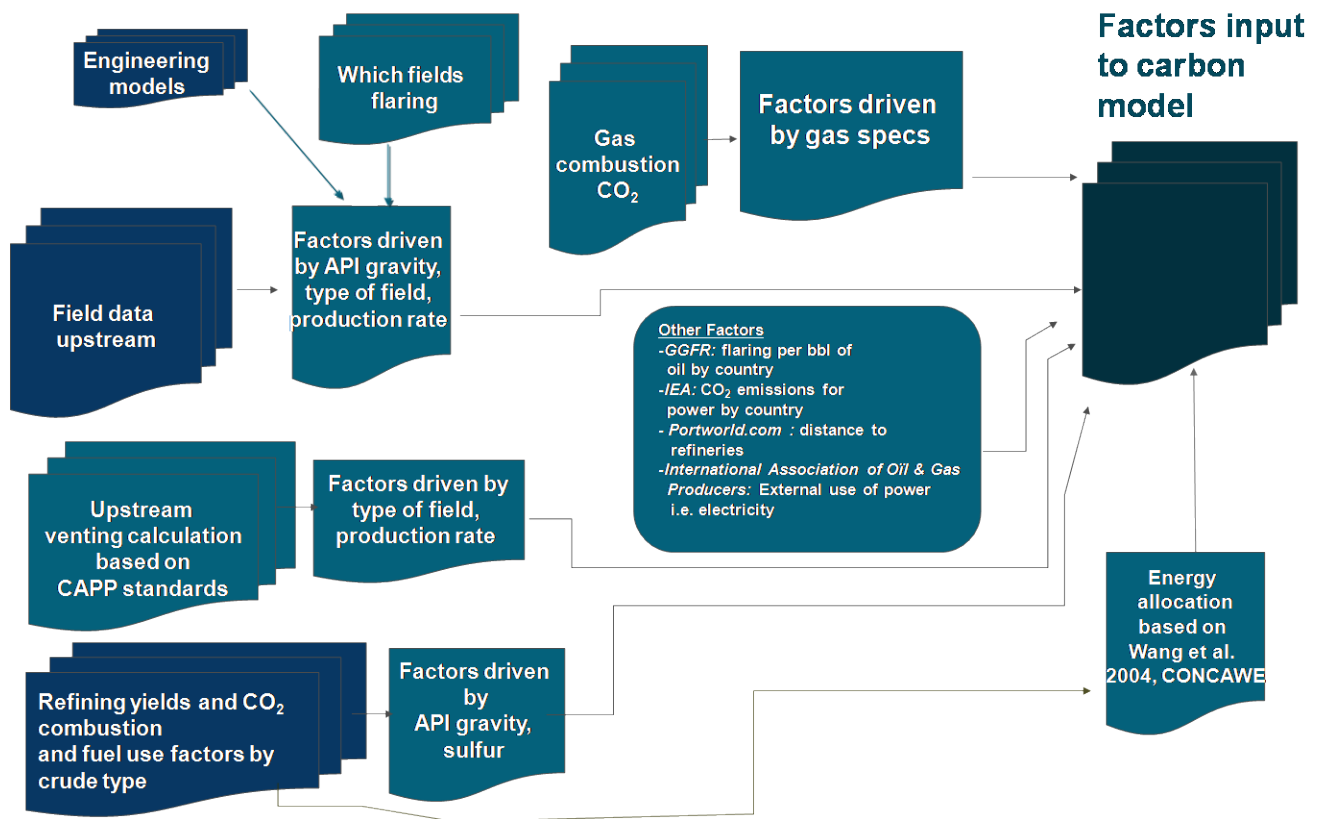


Figure 2. Inputs into Energy-Redefined LLC calculation methodology.

We also drew on the work of the GREET model (Wang, 2010), which was developed to estimate U.S. emissions associated with end use. We made use of this model to estimate transportation emissions only.

By using these various models and databases (Fig. 2), we have been able to create nonlinear algorithms that better represent the energy and carbon emission potential from the different types and sizes of fields contained with an individual company's portfolio.¹³ That is, emissions are not construed simply as a linear function of production or some combination of functions based on crude type.

We have calculated the emissions and energy use including the impact at different points in the value chain (Fig. 3).

¹³ Although we have not estimated company portfolio effects, our methodology enables the estimation of emissions intensities on a company basis.

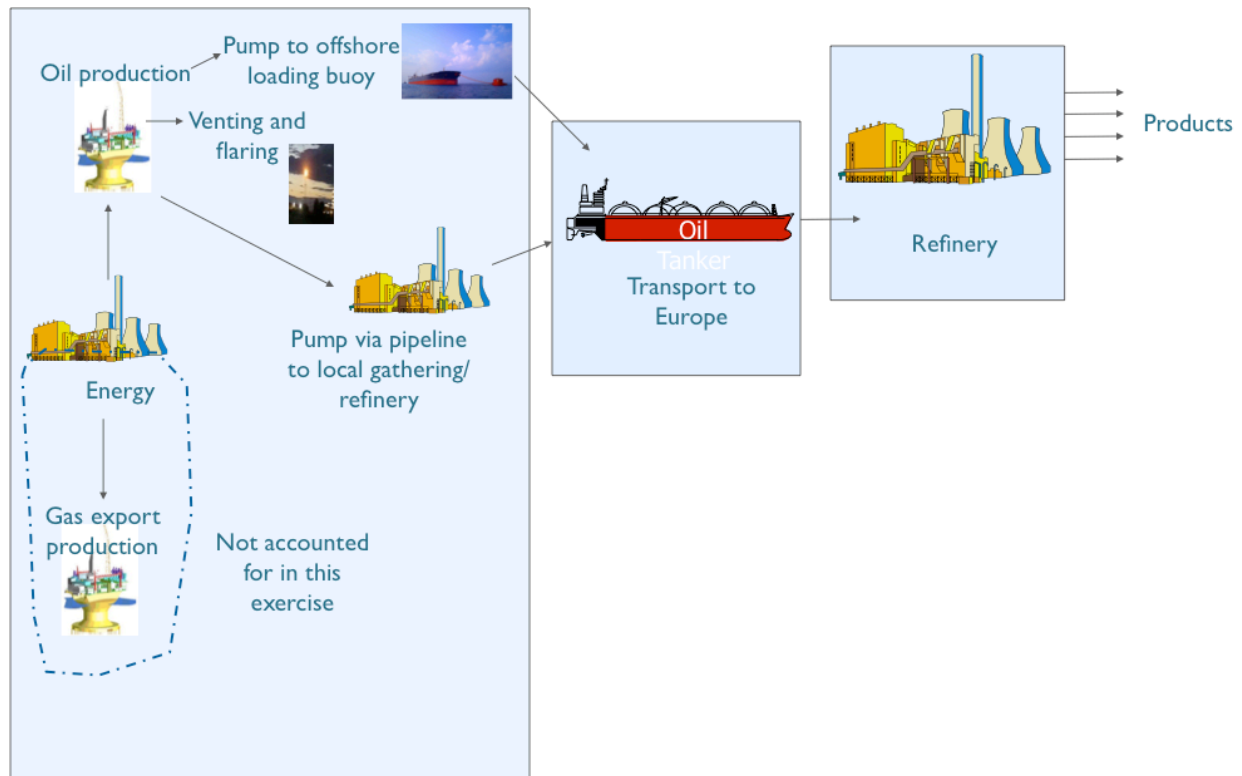


Figure 3. Carbon emissions chain.

With the appropriate design of the output tables, Energy-Redefined LLC has been able to slice and dice these emissions data in a variety of ways, including but not limited to:

- By country
- By field
- By development type
- By value chain element (e.g., wellhead operations and separation, flaring, venting, transportation to the refinery, refinery processing)
- By crude specification (i.e., API gravity, sulfur content)
- By gas specification
- By end product

Essentially we have used our database as a starting point to perform our calculations. In particular, we:

- Used this database as input to perform calculations to estimate emission by each field through time (2010, 2015, 2020)
- Collated and created an output database for further analysis
- Allocated emissions to end products with the use of an energy allocation algorithm
- Analyzed data, using clustering and categorization techniques, to elicit rules of thumb or other useful patterns
- Filtered the worldwide data to provide a European view, which required us to build a future scenario for imports into Europe 2015–2020
- Performed a sensitivity analysis on the results
- Summarized the results

In the sections below, we provide details of the assumptions and methodological approach underlying our analysis.

2.1 Extraction

Our emission factors are for the oil portion of the field only. Emissions associated with any gas exports have been excluded, although where fields are flaring we have accounted for this as associated with the oil production. This includes the oil's share of the fixed utilities for lighting, communications equipment, etc.

2.2 Tar Sands

Although we have good granularity on data for conventional fields, we do not have a rich data input set for tar sands projects (i.e., actual depths, pressures, viscosities, etc.). We therefore used the same average depth and pressure values for many of the tar sands projects in our data set, resulting in a flatter emissions intensity curve than may actually be the case (Fig. 4). We used reference data from numerous tar sands studies (Alberta Chamber of Resources, 2004; Brandt et al., 2007; Pembina Institute, n.d.; Woynillowicz, Severson-Baker, & Reynolds, 2005, p. 22) to generate our emissions intensities and to correct for depth, pressure, and type (efficiency) of generation. Note that although we referred to some of the earlier studies, we have in fact used emission factors from the later studies, because some of the earlier studies have emissions intensities that are too low. We have not included or considered any associated carbon capture and storage (CCS) schemes or applied any credits that may be potentially available from co-generation. This could lower the numbers presented herein. For older projects, we assumed that electricity used in the processing of tar sands is generated at an efficiency of 35%. We have assumed that upgrading of tar sands to synthetic crude oil (API gravity = 20) occurs onsite (i.e., at oil fields) and is delivered to a refinery.

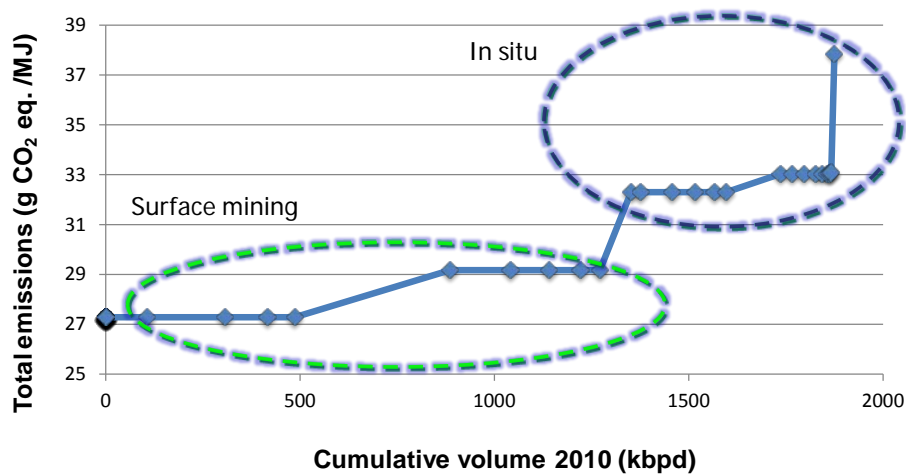


Figure 4. Tar sands emissions, from wellhead to refinery output gate.

Note that Figure 4 includes emissions from extraction, transportation to the refinery, and refining. Upstream-only numbers would be around 8 g CO₂ eq./MJ less. Studies on specific projects do exist.¹⁴ We refer you to these studies for a more detailed treatment of how emissions may vary with differences in processing and other assumptions.

The Economics of Co-generation in Tar Sands Projects

It is not always clear what type of electricity generation will be selected by producers for installation on their fields. Lower-cost installations will result from the use of simple-cycle gas turbines, but these have much lower efficiencies. It is an economic trade-off. Energy-Redefined LLC's own calculations on generic projects indicate that only larger projects will be able to economically install co-generation (i.e., combined-cycle gas turbines). Of course, this will be dependent on the specific setup of the site (e.g., whether upgrading¹⁵ is integrated with field

¹⁴ See various references on tar sands (e.g., Alberta Chamber of Resources, 2004; Brandt & Farrell, 2007). Note that earlier studies reported lower emission levels.

¹⁵ Bitumen (tar sands) consists of complex hydrocarbon chains. It is rich in carbon but deficient in hydrogen. Bitumen is upgraded to remove carbon and add hydrogen to obtain valuable hydrocarbon products. Upgrading results in synthetic crude oil, which can be transported easily via pipeline to refineries.

operations, whether the power is exported, etc.). It is also dependent on natural gas prices. At today's prices, \$3/mmbtu, only those projects larger than about 50 kbpd should be considering co-generation or higher-efficiency turbines to generate electricity for use at their projects. Other references cited when prices were \$5 to \$7/mmbtu claim a limit of 25 kbpd.

In the analysis presented herein, we have assumed that newer projects producing ≥ 50 kbpd of crude (at peak) would be generating their electricity at efficiencies of 50%.

2.3 Energy Use at the Field

The energy required to produce oil from fields varies not only with the quality of the product, but also according to various factors such as reservoir structure, number of wells drilled, pressure, depth injection strategy for pressure maintenance, enhanced oil production (EOR) strategy, etc. Currently we do not have data for each of the fields at this level, but in general, the more complex the process and/or the heavier the product, the more energy will be required to process and extract it.

A separate analysis of a hypothetical field, using a rule-of-thumb upstream energy model, has allowed Energy-Redefined LLC to construct an algorithm to estimate energy use at the field. This energy use is specific to field size, type, and specification. Energy demands also change through time. We discuss this point in more detail below. Actual plants may be more or less efficient. The results from this analysis were compared with some real data points and were found to be reasonable.

Some of the energy used at the field is provided by waste hydrocarbons, such as gas produced from the field. Sometimes this energy is imported from nearby fields or from the power grid. Without detailed data or knowledge of fields in this regard, it is difficult to know what the fields are actually doing, but we can make some reasonable assumptions. By estimating the energy use expended at the field in gigajoules per tonne of oil (see below), we are able to estimate the yearly need for energy by simply multiplying energy use per tonne (GJ/tonne) by a conversion factor for crude density (tonne/bbl or tonne/mmscf) and multiplying the result by the production per year. As already explained, this energy can be produced by burning gas or diesel fuel or by importing electricity. But in converting these products to electricity for heating or cooling, energy is lost, so the actual energy required is larger.

By dividing the energy required per year by an efficiency factor (we have assumed 35% for electrical power and 80% for boilers), it is possible to calculate the amount of gas or other fuel required to produce the required

amount of energy at the field. On an oil field¹⁶ most of the energy expended is in pumping, either for export or for reinjection and to run the utilities (e.g., lighting). This energy is usually generated from electrical power produced by gas turbines. Some fields generate all of their electricity; others import it from an external grid.

Imports of Electricity

Data published on a regional basis by the oil and gas producers (International Association of Oil and Gas Producers, 2009) provide some guidance on how much electricity is used at the fields. We have assumed that where a field is importing, it will do so on this basis. By using data from the International Energy Agency (2009) on the emissions from power plants by country (in g CO₂ eq./kWh), we can calculate the emissions from using this imported power. Some countries have a far greater mix of coal in their generation portfolio than others, so they would emit more CO₂ per kWh generated. This country-average approach assumes that the field is using power from the average generation portfolio, whereas in practice a particular field might source it from one type of power station, typically one nearby. We have adjusted for transmission line losses at 8%. Note that we have not made any adjustments for changes in the future generation mix.

Energy Drivers

Our analysis indicates that energy use is a function of:

- API gravity of crude (higher densities require more energy for export pumping)
- Viscosity of crude (higher viscosities require more energy for export pumping)
- Field type (e.g., fields that export offshore require different amounts of export energy than those required to pump oil through a pipeline to a terminal situated 100 miles away)
- Peak production, which drives the sizing of pumps (note that energy requirements for compressors and pumps do not decrease linearly over time; however, the efficiency of pumps and compressors decreases as flow is reduced)
- Field size (a fixed component of energy is required to drive buildings, control equipment, etc.)
- Gas specification, which determines the energy required for compressor or power use
- Cracking requirements for tar sands upgrading
- Gas requirements for heavy-oil production
- Water cut (i.e., the amount of water produced with the oil)

¹⁶ Not in the case of tar sands.

We have used our engineering models to develop algorithms that reflect energy use according to different crude characteristics.

Efficiency of Turbines

Newer fields might install combined-cycle gas turbine generators with efficiencies approaching 55%. For example, StatoilHydro (2006) has replaced its turbines on the Heimdal field to increase generation efficiency, resulting in lower carbon emissions. We have assumed an average 35% turbine efficiency in our calculations, except for Russia and Indonesia, where we make an assumption of 20%.

2.4 Flaring at the Field

Gas is usually produced in association with the oil, even though no volumes are being exported. Some of this gas, as discussed above, would be burned as fuel gas at the field to provide energy for extraction of the hydrocarbons or for processing. The leftover gas, if it is not exported, should be flared at a specially designed flare tip¹⁷ with efficiencies of 98%. Our model currently uses an efficiency factor of 98% for all fields.

Combustion of Gas

Natural gas comes in a variety of forms and is characterized by its composition. The heating value of unprocessed gas is considered to be greater than that of sweet gas, as it may contain ethane, propane, butane, and C₅+. For gas with a composition of 80% CH₄, 15% C₂H₆, and 5% C₃H₈+, the amount of CO₂ produced by stoichiometric combustion is 1.25 times the amount produced by combustion of pure methane (i.e., 2.33 kg/m³ vs. 1.86 kg/m³).

To calculate a CO₂ emission factor for a specific mixed gas composition such as aCH₄ + bC₂H₆ + cC₃H₈ + dC₄H₁₀ + eC₅H₁₂ + fCO₂, where a to f are mole fractions of the natural gas components, the following formula can be used:

$$[(a + 2b + 3c + 4d + 5e + f) \times 44.01] / 23.64 = \text{kg CO}_2 \text{ per m}^3 \text{ of fuel burned}$$

where 44.01 = molecular weight of CO₂, and 23.64 = the volume (in m³) occupied by 1 kmol of gas at 15°C and 101.325 kPa.

¹⁷ In many places this is not the case. We know of instances where open pipes are being flared.

The above equation assumes complete combustion of hydrocarbon components. Therefore, in our current model this applies to only 98% of the gas combusted at the flare; the other 2% is vented.

Venting

The methane emission factor for venting would be the methane mole fraction (% methane) multiplied by the volume vented and then by 678.4 (i.e., methane density in g/m^3). If the gas was all methane and 100% of it was vented, we would have 0.68 kg/m^3 of methane vented. In terms of CO_2 equivalents, we would have $0.68 \times 25 = 17 \text{ kg/m}^3$.

By calculating combustion and venting coefficients based on the above methodology and applying these to the relative proportions of gas fully combusted and gas vented, it is relatively easy to estimate flaring emissions, assuming that we know how much gas is being flared.

2.5 Which Fields Are Flaring?

Flaring at fields is an important determinant of carbon emissions intensity. The World Bank's Global Gas Flaring Reduction Partnership (GGFR) (World Bank, n.d.) occasionally publishes flaring volumes by country, which allows us to calculate annual flaring per barrel of crude produced in a given country. Although these reports provide country intensity averages, they tell us nothing about what happens at each field. Some fields might be flaring much more than the average, others not at all.

Satellite images of flare locations do exist and have been used to identify which fields are likely to be flaring. Note that in Figure 5 there may be multiple fields flaring in and around the flaring locations shown; that is, only larger flares appear in the figure. The Energy-Redefined LLC database includes locational variables (longitude and latitude) to identify fields that are near observed flares. Although this information helps us identify which fields are likely to be flaring, it does not tell us anything about the flaring volume at any particular field.

Fortunately, we can use a variable measured during well testing to help us estimate gas at the well as well as flared volumes. It involves the use of the gas-to-oil ratio (GOR). Note that GOR does not represent gas production divided by oil production, nor gas reserves divided by oil reserves.

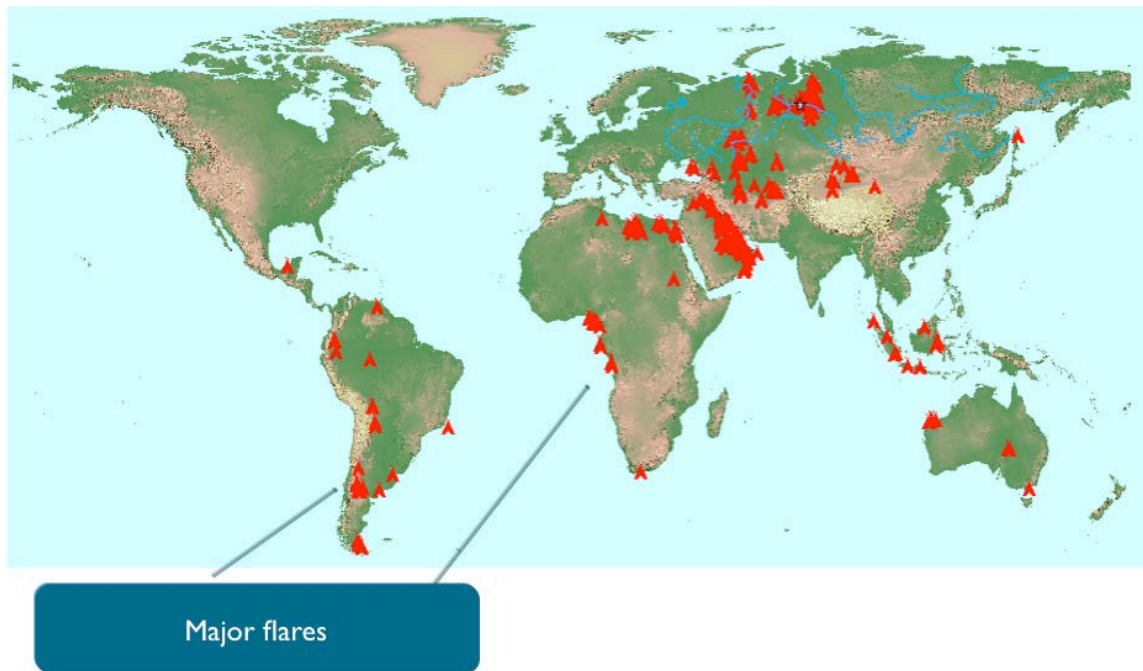


Figure 5. Worldwide flaring hotspots.

2.6 Gas-to-Oil Ratio: How It Affects Flaring Volumes

When oil is brought to the surface, it is usual for some natural gas to come out of solution. The gas is dissolved in the oil when under pressure. It escapes when the pressure is released, much as carbon dioxide escapes when a soda can is opened. The GOR is the ratio of the volume of gas that comes out of solution to the volume of oil at standard conditions; it is usually measured in scf per barrel of oil or condensate. If the GOR is greater than 10,000 scf/bbl, then the field is usually described as a gas well. If it is less than 10,000, then the field is generally described as an oil well.

Because flared gas volumes are not measured at many individual wellheads, it is impossible to state independently and conclusively how much gas is being produced at the wellhead and therefore how much is being flared, but it is possible to estimate this quantity on the basis of known characteristics of oil production. Energy-Redefined LLC has estimated the amount of flared gas produced at each of the fields with the use of a field-by-field model that includes oil production, GOR, and the production profiles displayed by fields of different characteristics over time.

The GOR of a producing field is not constant (Beliveau, 2004; Muskat, 1949); it increases during a field's early life and decreases at the end of its productive life. The exact pattern of this increase and decline depends on the

nature of the field's drive mechanism, or the way in which pressure is maintained in the reservoir, most commonly as a result of water flowing in as oil is removed. Figure 6 shows the GOR profiles (expressed as the ratio of production GOR to initial solution GOR) for a range of typical water drives (weak, medium, and strong) and a solution gas drive. The medium water drive curve best approximates the behavior of the oil fields of Western Siberia, for example. For these fields, the production GOR peaks at more than 3 times initial rates when production reaches 65% of the field's total. However, for some fields this factor is 8 times the initial GOR.

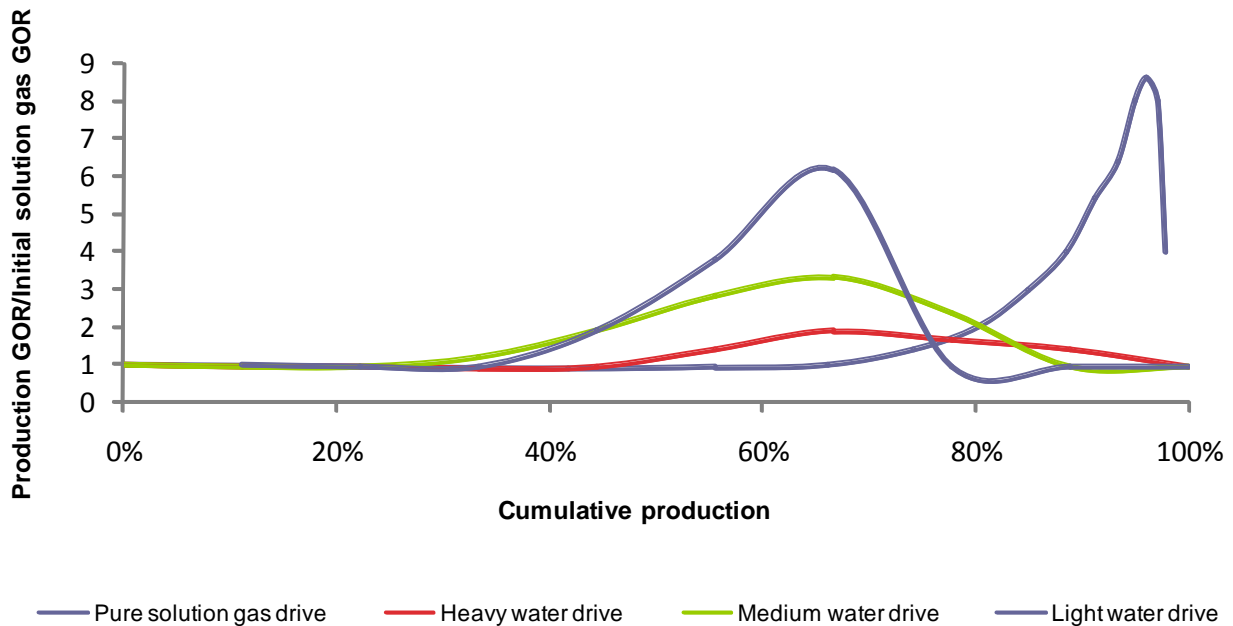


Figure 6. Ratio of produced gas throughout field life.

There are four major types of drive mechanisms:

- Water drive
- Gas cap expansion drive
- Solution gas drive
- Combination drive

A water drive is a reservoir drive mechanism in which oil is produced by the expansion of the underlying water and rock, which forces the oil into the wellbore (Fig. 7). In general, there are two types of water drive: bottom-water drive, in which the oil is totally underlain by water, and edge-water drive, in which only a portion of the oil is in contact with the water.

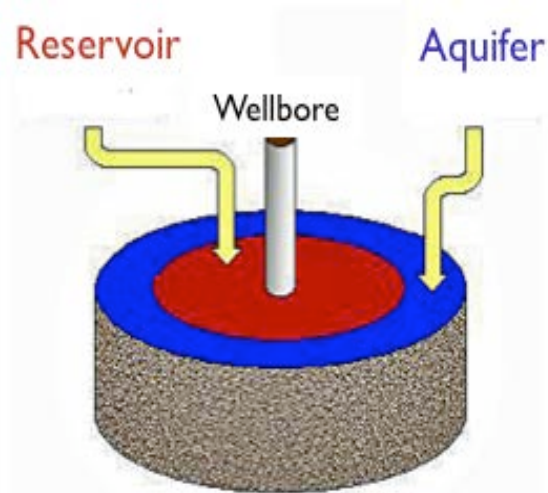


Figure 7. Simple radial model of water drive.

A reservoir driven by gas cap expansion is similar to a water-drive reservoir. In this situation, the gas cap expands to maintain the reservoir pressure. A gas cap expansion drive is not as efficient as a water drive.

A reservoir driven by solution gas is the least efficient method. In this situation, as the pressure in the well decreases, gas comes out of solution from the oil. This gas will slow the pressure decline.

Generally, a reservoir drive mechanism will be a combination of the above three mechanisms, with one mechanism dominating. A water-drive reservoir can actually be 70% driven by water, 20% by gas cap expansion, and 10% by solution gas.

Without detailed geological data, it is difficult to know which of these mechanisms is at play in any given field. However, the relative permeability of the reservoir and the viscosity of the crude are usually the primary variables involved.

In gas-drive reservoirs, GOR evolution through time is dependent on viscosity. Viscosity is a measure of the resistance of a fluid to flow—that is, how much shear force is required to cause the fluid to start to move and continue moving. There is an inverse relationship between viscosity and flow. In reservoirs partly or primarily driven by water, an important parameter (Dake, 1978) in determining the effectiveness of water flow in a reservoir is the endpoint mobility ratio (M), defined as

$$M = \frac{k'_{rw} / \mu_w}{k'_{ro} / \mu_o}$$

where k'_{rw} is the endpoint relative permeability of water, k'_{ro} is the endpoint relative permeability of oil, μ_w is the viscosity of water, and μ_o is the viscosity of oil. k'_{rw} and k'_{ro} typically take on values between 0.2 and 0.8. If we assume that water viscosity and the ratio k'_{rw}/k'_{ro} are constant, then the mobility ratio is a function of viscosity.

As an approximation, we used viscosity to create a GOR profile for each of the fields. In Figures 8 and 9, we show the distribution of the viscosities of the fields in our database as well as an estimate of the type of drive (strong to weak).

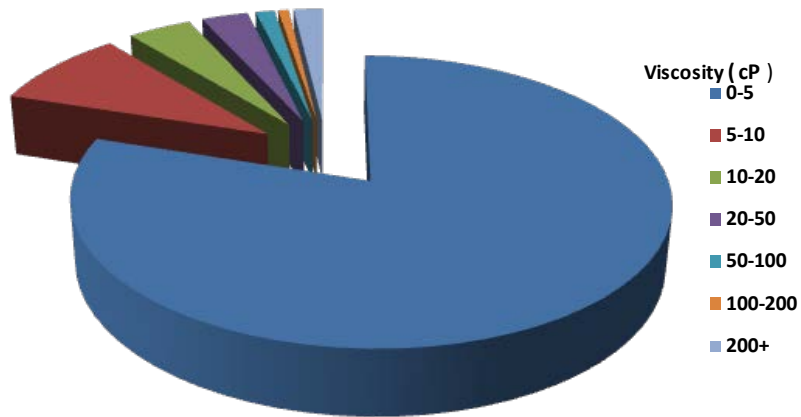


Figure 8. Distribution of crude viscosities.

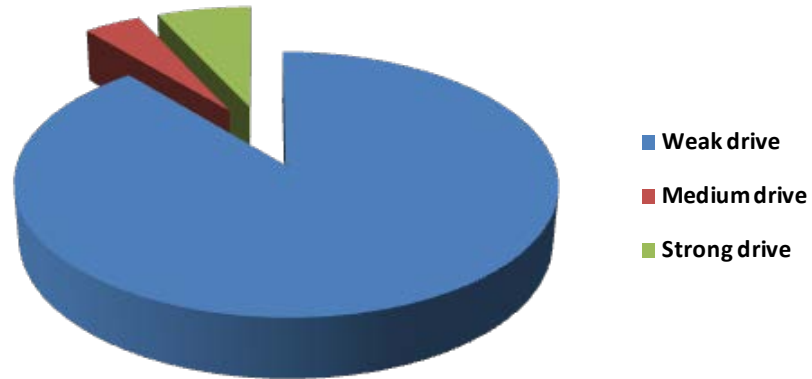


Figure 9. Distribution of reservoir drives.

This type of analysis also leads to the conclusion that the production GOR, and flaring as a whole, may well increase even as oil production declines. Flaring profiles at individual fields will vary, and understanding these individual profiles will be important in estimating future emissions profiles.

2.7 Flaring Estimation by Field

By using the satellite location data in combination with the GOR and energy use data discussed above, it has been possible to estimate flaring volumes and therefore calculate flaring emissions. Figure 10 presents an overview of our methodology.

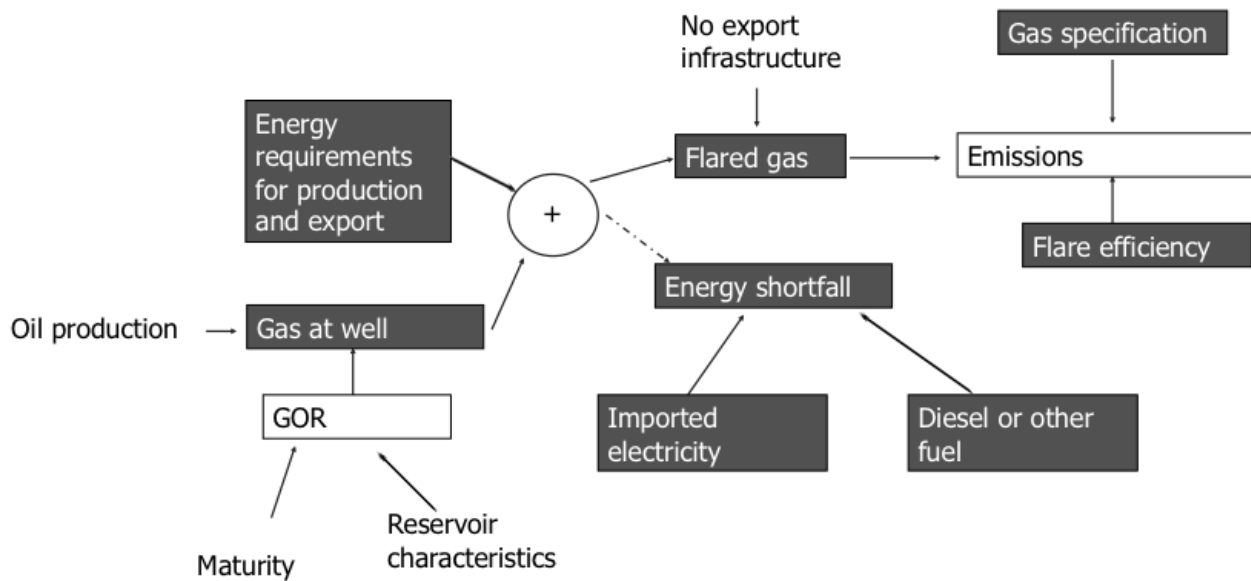


Figure 10. Flaring, GOR, and energy use.

Oil production multiplied by GOR (initial solution gas modified by the characteristics of the field and its maturity) yields volume of gas produced at the wellhead (in mmscfd). Some of this gas will be used to generate electricity for export, pumping, and injection (as discussed above, this is the energy required at the field). A smaller amount will be used to provide heating. Our calculations of energy required at the field tell us how much gas will probably be used. If there is more gas at the wellhead than is required for running the field, then the leftover gas is assumed to be flared, assuming no export.¹⁸ If there is a shortfall in the gas required for producing electricity and heat, then either electricity will be imported or some other fuel such as diesel will be used.

To summarize:

- We have used locational data for ~6000 fields to highlight fields near observed flaring sites, as identified by satellite images.
- We have assumed that where fields are exporting volumes of gas, they are not likely to be flaring. Note that there may be exceptions to this rule, but these are likely to be few.

¹⁸ We know which fields are exporting.

- We estimated gas at the wellhead from GOR figures. Note that our GOR figures change with maturity. We estimated fuel requirements to calculate how much gas will be required for oil field use. Volumes left over were deemed to have been flared. Note that gas with higher fuel contents (i.e., with more NGLs) will produce more energy for the same volume.
- We calibrated and checked against country averages published by GGFR.

Using this approach, we found that bottom-up flaring volumes correlated strongly with aggregate country volumes in nearly all cases. Exceptions tended to be countries such as Argentina, where there are numerous small fields. In such cases we tended to underestimate total volumes; a correction factor was applied to these few countries.

In the production of oil, there will be times when gas is flared for emergency reasons (e.g., at startup or shutdown, or during times of production constraints because of equipment problems). These will be infrequent and small. We have not accounted for these volumes.

2.8 Fugitive Emissions

In the natural course of production (and transportation), gas leaks from flanges, valves, and process equipment into the atmosphere. These unintentional emissions from pipe fittings and rotating equipment seals are known as fugitive emissions. The amount of gas that is vented is a function of the volume and the complexity of the plant. In addition, the effect of venting is related linearly to the amount of methane in the gas.

Over many years, CAPP has developed a detailed methodology for estimating these losses, which would require the counting of every valve, flange, and vessel in each field and/or plant. This is obviously beyond the scope of this study. We instead used an alternative methodology¹⁹ to estimate these losses, based on actual plant operations.

This less detailed method uses a generic or average fitting count for specific equipment or processes, from which the number of valves and therefore the fugitive emissions can be estimated. These generic fitting counts used were taken from an API fugitive emission study of 20 different facilities in 1993 (American Petroleum Institute, 1993). The fitting counts do not distinguish how many fittings are in liquid or vapor service. Equipment with both liquid and gas fittings, such as separators and dehydrators, can be considered to have 50% of its fittings in gas service (i.e., as an approximation).

¹⁹ CAPP Greenhouse Gas Emissions Calculation, April 2003.

Casing Gas

Casing²⁰ gas vents are a particular concern for heavy-oil and crude bitumen wells. Heavy-oil wells are relatively shallow (typically 900 to 3000 ft deep) and thus are characterized by low reservoir pressures (typically 4000 kPa or less²¹). To achieve reasonable flow potential, it is necessary to relieve gas pressure from the well bore (downhole pressure of about 250 kPa is maintained). Such wells are not usually equipped with a production packer (a device that isolates the annulus from the formation). This allows the well pressure to be controlled using the casing vent. Because of the low volumes of gas associated with primary heavy-oil casing gas, the gas is typically vented directly to the atmosphere. Recently, conservation schemes have begun to be implemented. For thermal heavy-oil projects, the gas is usually flared or conserved because of the potential for H₂S in the gas.

As explained above, the volume of casing gas vented or flared is primarily a function of the quantity of gas in the reservoir (i.e., GOR) and wellhead conditions. Values of GOR may vary substantially from well to well, even for wells producing from the same pool; they can range from 10 to 5000 scf/bbl (for associated gas).

Table 3. Wellhead venting emissions. THC, total hydrocarbons.

Emission source	Description (solution gas is off stock tanks)	THC emission factor (m ³ /m ³ of oil production)
Conventional oil	Solution gas (no treater in process)	5.0
	Solution gas (with treater in process)	3.2
	Solution gas (with gas boot in process)	0.5
Primary heavy oil	Casing gas produced	59.2
	Casing gas vented (63.2%)	37.4
	Solution gas produced	1.0
	Solution gas vented (38.7%)	0.4
Thermal heavy oil	Casing gas produced	53.9
	Casing gas vented (4.7%)	2.5
	Solution gas produced	8.3
	Solution gas vented (0%)	0.0
Crude bitumen	Casing gas produced	12.9
	Casing gas vented (18%)	2.3

²⁰ The metal pipe or tube used as a lining for the oil well. Casing gas refers to the leakage around the casing pipe.

²¹ Approximately 600 psi.

Because of this wide variation in GORs, accurate estimation of casing gas flow necessarily involves establishing an accurate GOR by measurement. We have estimates of these GORs in our databases, but in this instance we have elected to use the CAPP factors (CAPP, 2003) summarized in Table 3.

2.9 Maturity of Production—Its Effect on Energy Use

The maturity of production is an important driver of emissions through time (Fig. 11). Emissions from the same field 20 years after first production can increase by as much as a factor of 10 to 20 over emissions at the start of production. This increase is driven by a number of factors, including but not limited to:

- Gas and water injection for secondary recovery
- Oil flow rates
- Water cut/water production

Although it would be possible to develop a model that drives emissions according to water cut profiles and the like, this would be a complicated task. We have instead opted for a simpler approach based on a study by Vanner (2005) performed on actual emissions from a number of case studies. This study yielded a profile of how emissions vary through time for three different types of fields: pure oil, pure gas, and oil/gas.

Key events in life of oil/gas field

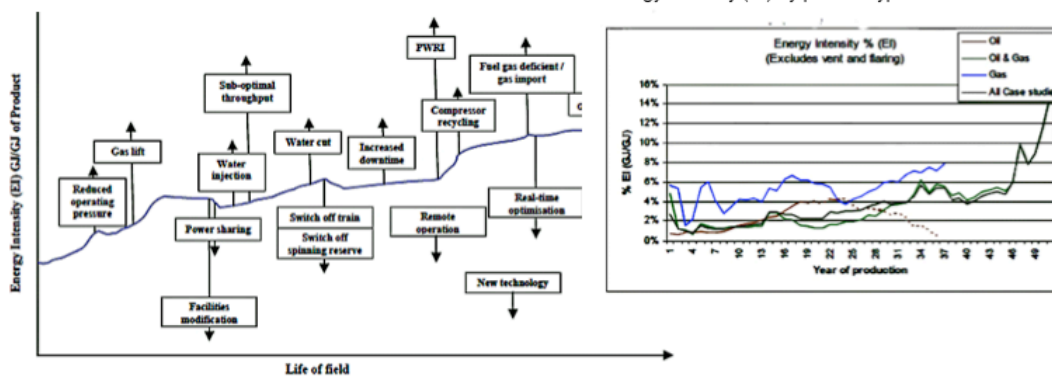


Figure 11. How energy use changes with field maturity. Taken from Vanner (2005).

Using our own case studies and calculations and comparing our results with this study, we have determined that these profiles fit certain types of fields. We have developed an algorithm that allows us to modify the curves to fit different reservoir and field characteristics and to apply them to fields around the world. This algorithm accounts

for differences in depth, pressure, API gravity, whether the field is offshore or onshore, and whether it is or is not exporting via a pipeline. This allows us to adjust emissions intensity profiles associated with production through time.

2.10 Transportation

Once oil is collected from oil fields and blended at receiving points or terminals, it is transported to a refinery for processing. For longer distances, such transport is usually by oil tanker. We have used the GREET methodology for oil tanker transportation to estimate emissions associated with moving the crude from the applicable country to a European refinery. We determined country-average sailing distance with the PortWorld Ship Voyage Distance Calculator (PortWorld, n.d.).

2.11 Refining

Once crudes are produced, they are typically mixed at a terminal before shipment to a refinery (Fig. 12). The refinery, depending on how it is set up, will produce different products (e.g., gasoline, diesel, etc.) at different levels. The yields of these products will vary with crude input and refinery processing setup.

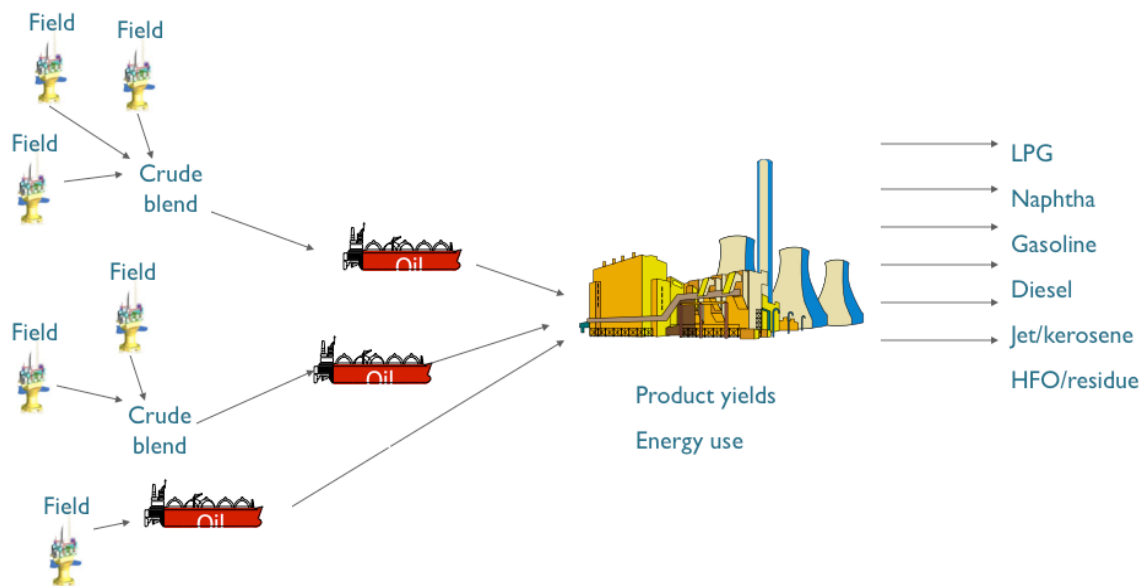


Figure 12. Refineries processing different crudes. HFO, heavy fuel oil.

Different crudes require different amounts of processing energy and produce different product slates. Modeling of product yields and associated processing is a standard technique within the refining industry. The technique is

used to derive crude yields, so that the marginal effect of adding or reducing particular types of crude in the refinery can be determined. This is a complicated exercise that can be accomplished through process modeling, but in this instance we have chosen to use a simpler modeling technique. We have used a relationship derived by other authors (Keesom et al., 2009; Wang et al., 2004) and modified this to reflect the processing energy requirements of European refineries. This linear relationship estimates energy use, and therefore emissions, as a linear function of crude API gravity. Figure 13 shows the Keesom et al. relationship along with our own data from selected refineries around the world. Using data from the CONCAWE Refinery Technology Support Group (2008) study, we recalibrated the Keesom et al. relationship to represent more closely what would be found at a European refinery.²²

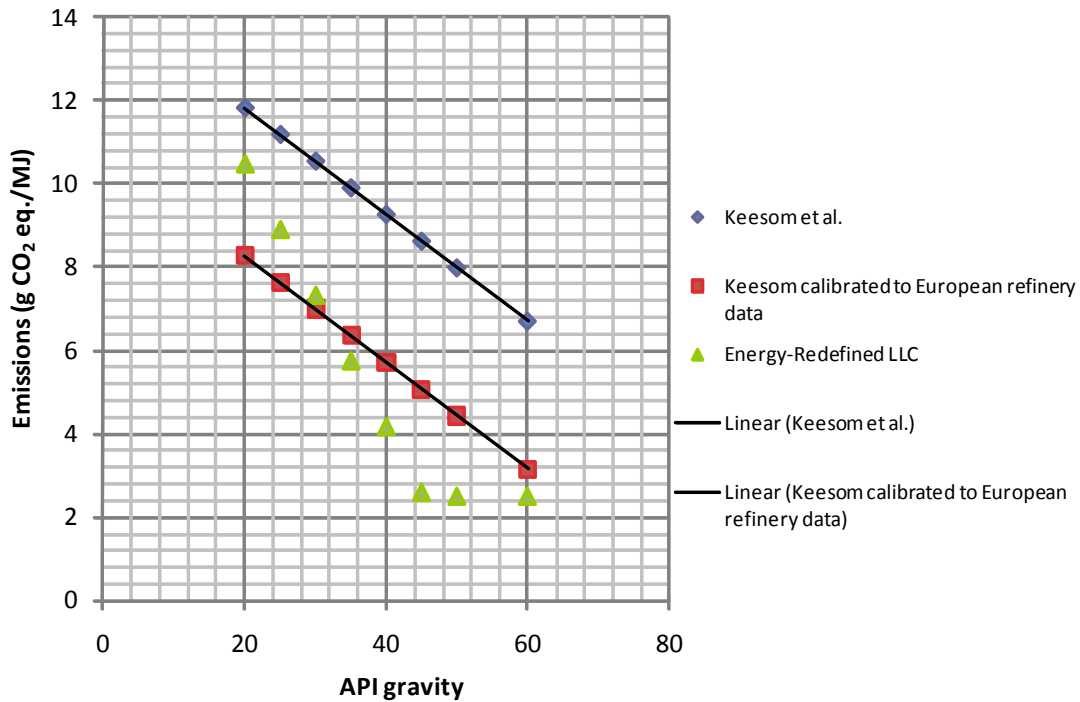


Figure 13. Relationship between crude API gravity and refinery emissions intensity.

²² We cross-checked this number with data from BP's sustainability report. BP has an average refining and marketing emissions intensity of 7.2 g CO₂ eq./MJ (43 kg CO₂ eq./bbl).

2.12 Allocation of Emissions to End Products: Energy Use

The allocation of CO₂ equivalent (CO₂ eq.) emissions to the final products of a given refinery can be done in different ways—by volume, by mass, or by energy consumption (Fig. 14)—and can produce markedly different results. Here, we drew on an energy analysis methodology presented by Wang et al. (2004). We used table 2 of Wang et al. and modified it to reflect an average European refinery setup. Although in practice the allocations will change with crude slate (i.e., API gravity), our analysis assumes a constant allocation.

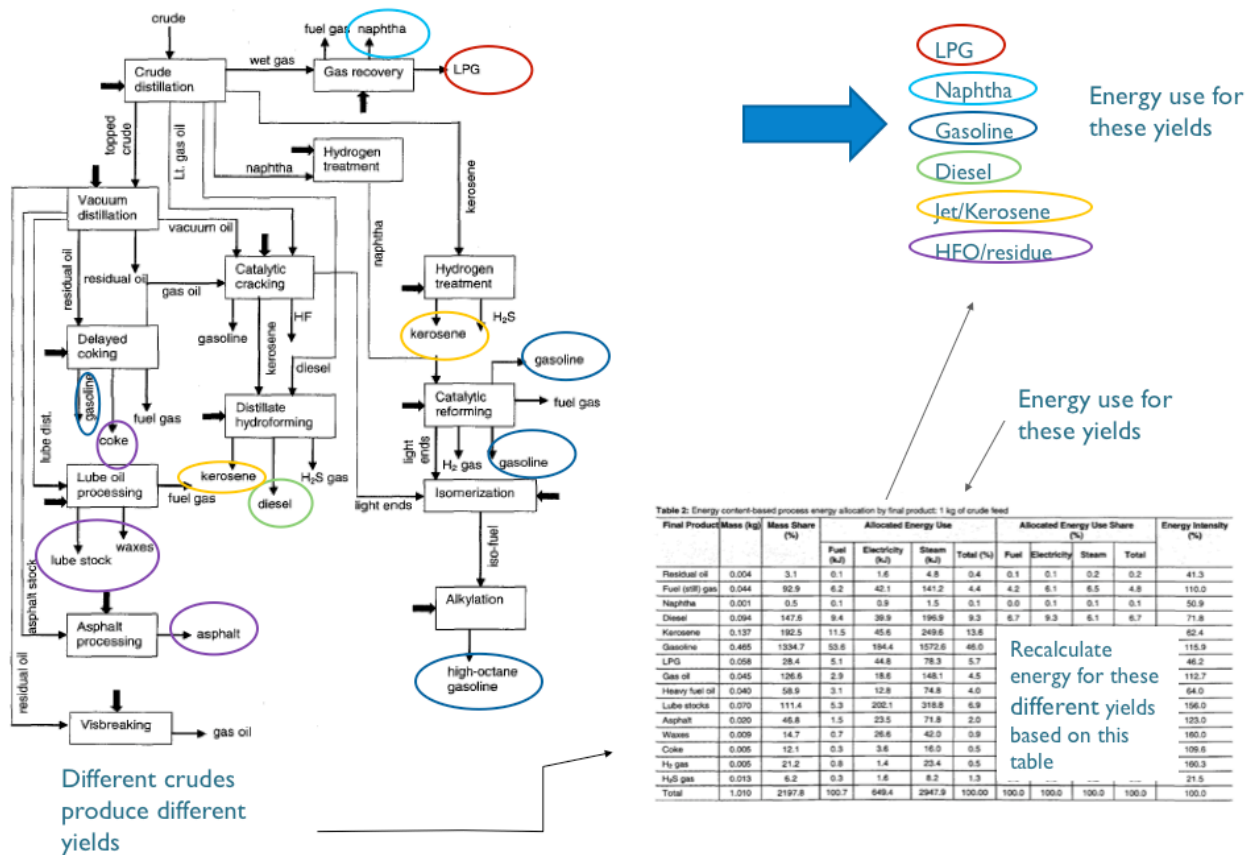


Figure 14. Energy and emissions allocation.

2.13 Company Reports and Public-Domain Documents

To calibrate and check our data, we reviewed public-domain reports from companies and other sources. Our bottom-up approach generally calibrated well with aggregate data reported in the public domain. In several instances where the data did not compare well, we adjusted our calculations to provide aggregate results consistent with reported numbers, as noted below.

2.14 Global Warming Potential Factors

Global warming potential (GWP) factors are used to convert the “non-CO₂” gas (e.g., methane and nitrous oxide) to an equivalent CO₂ mass (CO₂ eq.). These factors take into account the relative impact of different GHGs on the atmosphere and the differing lengths of time they reside in the atmosphere. Table 4 lists the GWP factors used in this study.

Table 4. Global warming potential (GWP) factors (Forster et al., 2007).

Gas	100-year GWP
CO ₂	1
CH ₄ (methane)	25
N ₂ O (nitrous oxide)	298

As is the usual practice, the conversion to a carbon dioxide equivalent mass is calculated as follows:

$$\text{CO}_2 \text{ eq. (tonnes)} = \text{CO}_2 (\text{tonnes} \times 1.0) + \text{CH}_4 (\text{tonnes} \times 25) + \text{N}_2\text{O} (\text{tonnes} \times 298)$$

2.15 Production Data: A Shortfall in Production to Meet Demand 2015–2020

Our production data include existing production, fields under development to be producing shortly, and fields that are being assessed by companies at this moment and may be in production within the next 5 to 10 years. By their nature, fields in the last category are less certain. As shown in Figure 15, total production for the worldwide data set used in this analysis declines in the later years. This planner's droop, as it is known, is not real. Production would typically remain high and could even grow.

In practice, oil companies have discovered oil fields that have not yet been considered in their development plans. Infill drilling of existing fields will occur, and wildcat exploration activities will discover new fields. Although it might be possible to devise a model that includes such events, we have decided to take a simpler approach. In this simpler approach we have used a clone or lookalike of the fields that either were recently developed (since 2007) or are expected to come online in the near future, and scaled those fields appropriately. Prior work has shown that the new production is likely to resemble production developed over the past 5 to 10 years, albeit with field sizes a little smaller.

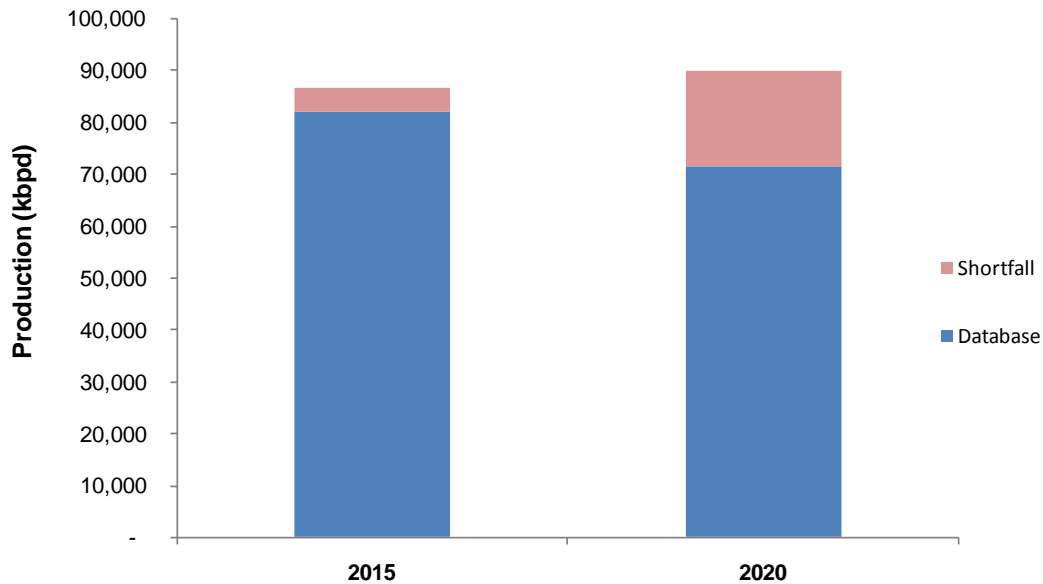


Figure 15. Estimated worldwide production shortfall.

2.16 European Imports

Although we have used a worldwide database, we have filtered it further to exclude those fields (or, more specifically, countries) that do not export to Europe. Our starting point in this exercise was the 2009 (2008 figures) BP Statistical Review of World Energy inter-area movements table (BP, 2009). Note that Europe also exports crude mainly from the United Kingdom and Norway to other countries in the world. About 50% of crude produced in the United Kingdom and Norway is exported.²³ Our analysis only considers imports. We have no way of knowing which of the fields export to Europe and which do not, but we know that certain countries export certain volumes on average.²⁴ We have used this knowledge to scale our worldwide data to produce a European view. We show this for 2010 in Figure 16 (note that this reflects upstream production only). Very low values are

²³ We have assumed that the same export ratio will apply to future production.

²⁴ This is not strictly true. We have excluded fields or regions of countries that we know are not exporting to Europe.

associated with fields that are producing condensate, have recently started production, and have no flaring. Our methodology apportions energy between oil and gas production within the same field, so this can result in very low values.

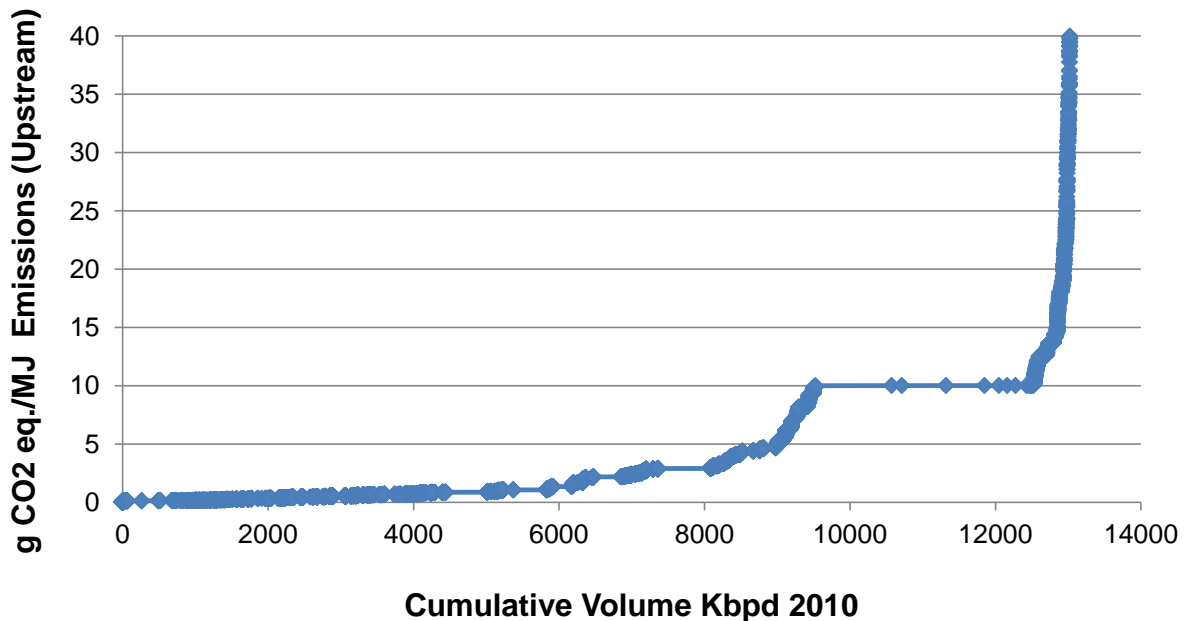


Figure 16. Upstream crude intensity for European imports (year 2010).²⁵

We have used the 2008 BP statistical review numbers (BP, 2009) as a guide to 2010 exports. Demand levels during 2010 have fallen to around 2008 levels, so this seems a reasonable assumption. But this will not be valid for later years. This is particularly so for tar sands imports from Canada, which are likely to grow to as much as 500 kbpd. This has necessitated a future import scenario for 2015 and 2020 (Figs. 17 and 18). To create this future view, Energy-Redefined LLC made use of the U.S. Energy Information Administration (EIA) International Energy Outlook reference case scenarios for 2015 to 2020 (EIA, 2009). In this scenario the United States is not seen as requiring more imports than it does now, whereas Canadian

²⁵ Note: Figure 16 was originally published erroneously showing the 2020 projected volumes and intensities rather than the 2010 figures. This has been corrected.

tar sands production could rise from around 1000 kbpd to around 4000 kbpd (CAPP, 2005, p. 2). Europe is expected to increase its need for imports by about 1400 kbpd by 2020, representing a 10% increase in demand.

Looking at needs from other countries such as China and India and potential flows around the world, Energy-Redefined LLC has used its expertise and knowledge of oil flows to construct a scenario of how additional production might flow to meet the additional incremental demand. Of course, in practice, flows may not turn out this way as political considerations or other economic factors come into play.

Our scenario for the years 2010, 2015, and 2020 is summarized in Figures 17 and 18, which show the projected total imports into Europe from the various countries and the additional volumes that would be required over 2010 volumes. Note that we have not applied the scaling factor to every country or field within that region. Where we have information that fields or countries are not exporting to Europe, we have excluded them.

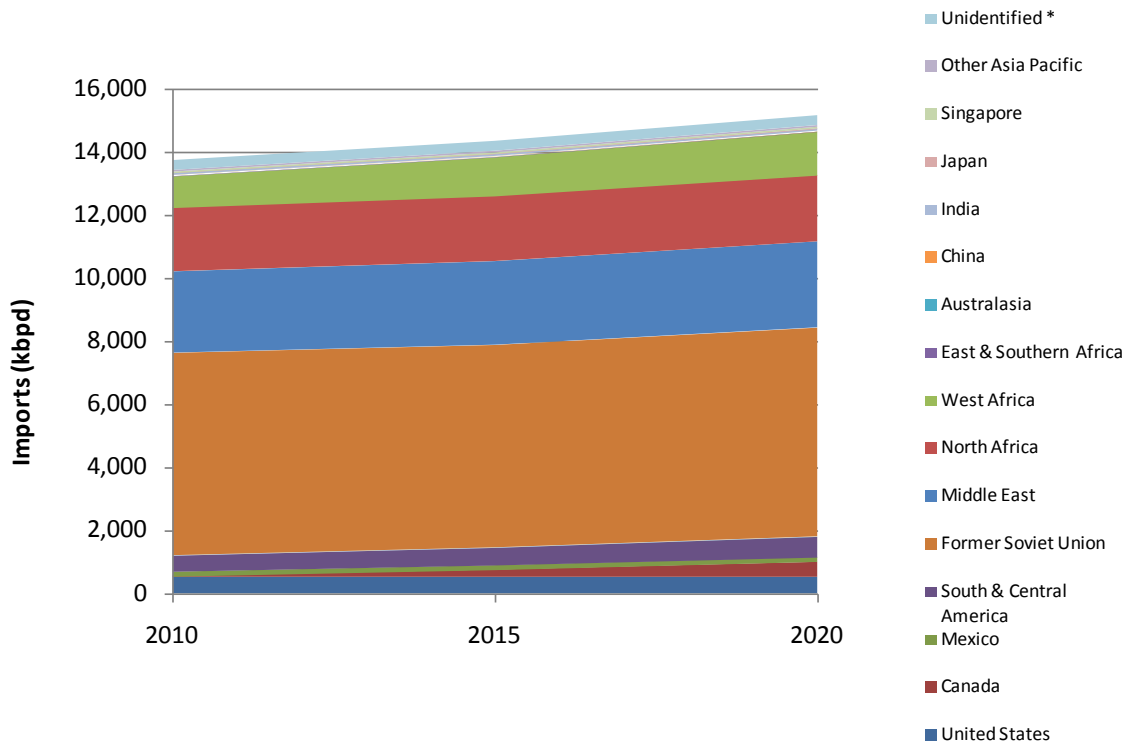


Figure 17. Projected crude oil imports into Europe. Unidentified refers to the unaccounted volume due to loss, lack of accurate measurements, etc.

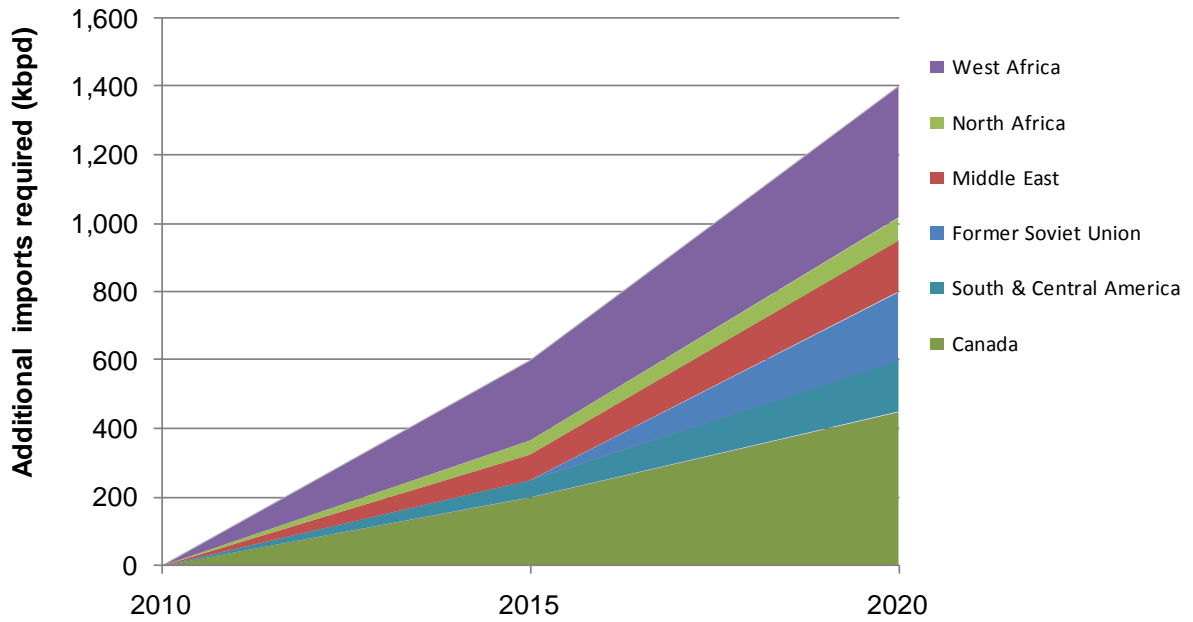


Figure 18. Additional crude imports into Europe over 2010 case.

About 80% of these crudes imported into the EU have API gravities in the range 30 to 40 (Fig. 19).

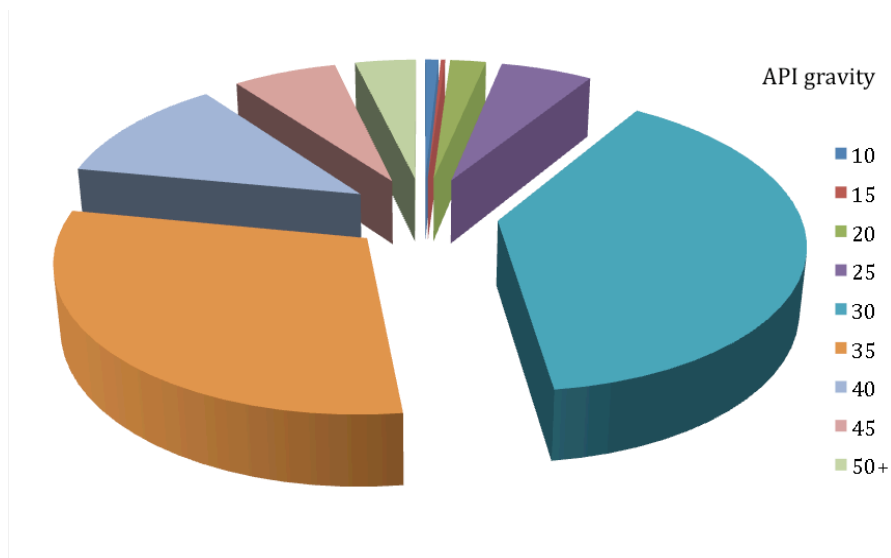


Figure 19. Crude imports into Europe during 2010 by API gravity.

3. Analysis and Results

Using the calculation methodology discussed above, Energy-Redefined LLC has compiled an extensive database of emissions intensities by field. An example of the results is shown in Figure 20.

Field Name	Total Upstream							Total upstream >> Refinery Tank kg/boe
	Oil Production Kbbbl/d	Upstream Kg/boe with indirects	Oil/ Condensate Extraction kg/boe	Venting Kg/boe	Flared Gas3	Transport kg/boe	Refinery Fuel Kg/boe	
Yanchang China	202.1	24.6	9.5	0.9	14.2	1.9	21.1	47.4
Yumen China	12.6	10.2	9.9	0.3	0.0	1.9	21.1	33.2
Sichuan China	2.5	24.8	10.5	0.9	13.3	1.9	25.2	51.4
Tuha China	37.7	9.9	9.6	0.3	0.0	1.9	25.2	37.4
Jiangsu/Azhui China	30.8	37.9	37.9	8.2	14.8	1.9	37.0	76.4
Shangji China	499.3	18.9	8.4	10.5	0.0	1.9	37.0	57.4
Zhongyuan China	54.1	37.9	8.1	14.9	14.9	1.9	37.0	76.4
Henan China	32.5	10.6	7.6	0.6	0.0	1.9	41.2	51.2
Jianghan China	17.4	10.8	7.8	0.6	0.0	1.9	41.2	51.2
Dianqiangui China	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NewStar China	117.4	10.5	7.4	0.6	0.0	1.9	41.2	51.2
Suizhong 35-1 China	42.0	20.5	2.7	12.4	5.4	1.9	36.3	58.4
Luda 4-2 China	39.0	25.7	3.3	14.4	8.0	1.9	36.3	63.4
Chengbei China	1.7	18.4	3.8	13.2	0.0	1.9	36.3	55.4
Qikou 15/1-2 China	1.7	19.6	4.7	13.2	0.0	1.9	36.3	56.2
Nianbo 35-2 China	1.5	18.6	1.5	13.9	4.6	1.9	36.3	58.2
Qinghuangdao 32-6 China	20.5	17.7	1.5	13.6	2.6	1.9	36.3	55.4
Penglai 19-3 China	65.0	29.0	2.2	14.9	11.8	1.9	36.3	67.2
Bozhong 34-2 China	1.0	28.1	6.4	14.3	7.4	1.9	36.3	66.2
28-1 China	20.5	34.7	1.6	15.8	17.4	1.9	36.3	72.2
25-18 China	20.5	14.8	1.6	13.2	0.0	1.9	36.3	53.4
Caofeidian 11/1-3 China	22.0	25.1	1.4	16.0	7.8	1.9	36.3	63.4
Caofeidian 11-6 China	22.0	25.1	1.4	16.0	7.8	1.9	36.3	63.4
Xijiang 24-3 China	6.5	24.2	3.8	1.4	19.0	1.9	21.1	47.2
Xijiang 30-2 China	4.0	165.2	3.6	13.7	148.0	1.9	21.1	189.2
Lufeng 11-1 China	1.9	121.3	2.7	27.2	91.4	1.9	29.9	153.2
Lufeng 13/1-2 China	3.8	17.7	4.7	2.0	11.0	1.9	21.1	40.4
Lufeng 22-1 China	1.9	22.0	3.3	0.9	18.0	1.9	21.1	45.4
Panyu 4-2 China	16.2	28.8	1.6	1.7	25.5	1.9	21.1	51.4
Wuzhou China	20.5	104.4	1.4	11.4	91.6	1.9	25.2	131.4
Wenshang 13/1-2 China	15.2	11.6	1.3	1.2	9.0	1.9	25.2	38.4
Yacheng 13-1 China	1.9	5.4	0.1	0.1	0.0	1.9	25.2	32.4
Dongfeng 1-1 China	20.5	1.9	1.5	0.3	0.0	1.9	25.2	28.4

Figure 20. Example of results output.

The output database that we have produced includes data for about 6000 fields or projects by country, by depth, by emissions intensity, etc. We have estimated emissions intensities for:

- Wellhead (export pump + reinjection + other energy)
- Venting at the production site
- Flaring at the production site
- Transportation from gathering station to Europe by tanker
- Refinery

An analysis of emissions data was carried out to look at patterns and clusters of the emissions intensities. The data were clustered using techniques such as radial basis functions, K-means clustering, and self-organizing maps. One of the objectives of this phase of the analysis was to see whether there was some way of simplifying emissions intensity values into ranges and extracting rules that defined these ranges. We found that it is difficult to do this accurately with simple algorithms. Before we discuss the clustering results, we discuss briefly the range of intensities found from this analysis.

3.1 Breakdown and Range of Emissions Intensities

Emissions from crudes imported into Europe could produce about 330 million tonnes of CO₂ equivalent emissions in 2010. The breakdown of these emissions from the wellhead to the refinery output gate is shown in Figure 21. Note that flaring and refining make up the largest share: 35% and 39%, respectively. Fugitive venting from valves and casings makes up only 6% of total emissions.

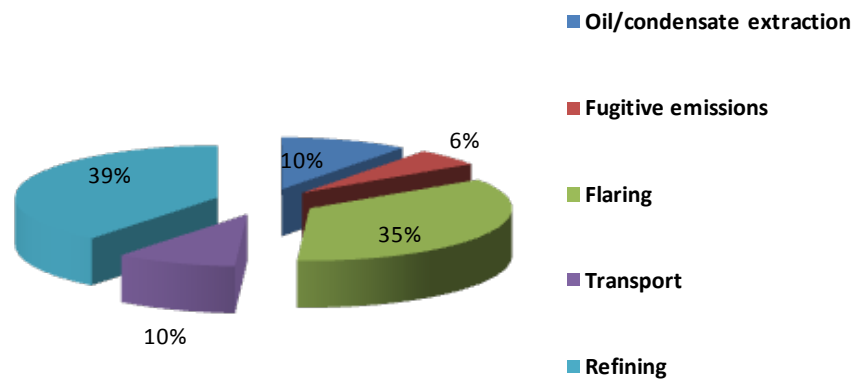


Figure 21. European crude import emissions breakdown.

Our analysis shows that emissions vary greatly by field type, country, and many other factors. This can be seen in Figure 22 for three example fields emitting at low, medium, and high intensity. We also include a tar sands field for comparison.

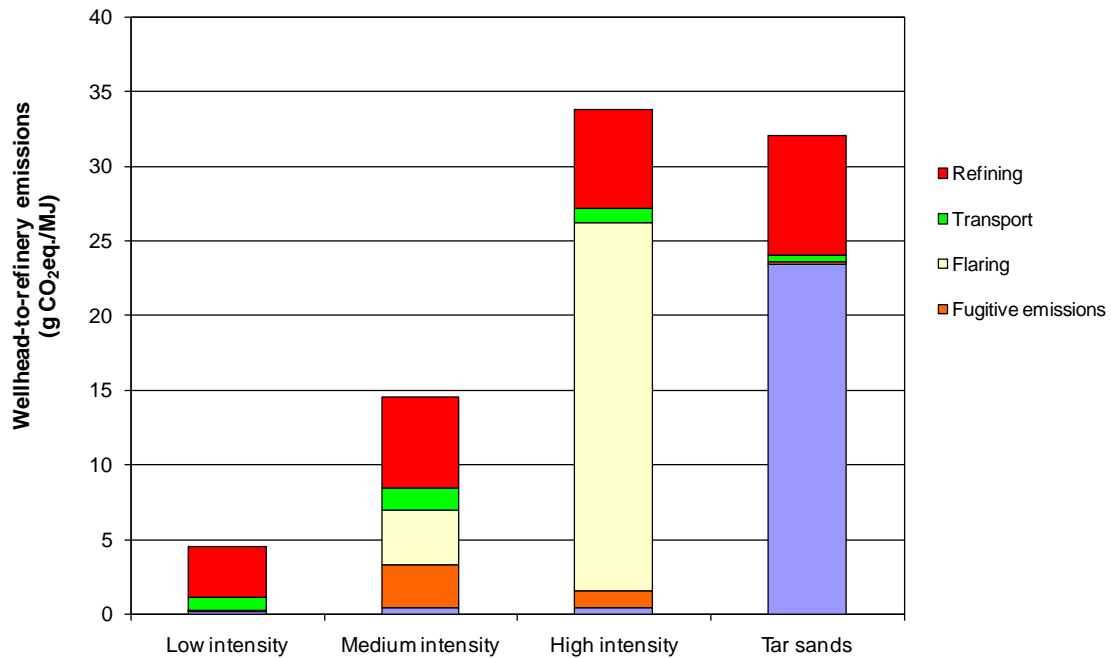


Figure 22. Breakdown of emissions for three example fields.

Note that different fields have different drivers that make up the intensity number. For example, the low-intensity field has no flaring or substantial venting component, whereas the high-intensity field has a very large flaring component.

Distribution of Intensities: Upstream

By sorting the data by intensity, we can create a profile of the emissions from smallest to largest (Fig. 23). Each dot represents one field. The distance between dots represents the production of the next field. It can be seen that the emissions intensities of upstream fields typically vary from 0 to 40 g CO₂ eq./MJ, although there are a few oil fields with upstream emissions greater than 40 g CO₂ eq./MJ. The figure represents the European view in 2010—a filtered view of the world profile to take into account only importing fields, as described above.

To better understand the ranges of GHG emissions for crude oil extraction associated with oil fields that flare and are tar sands, in Figure 24 extraction emissions are broken down into conventional oils with flaring, conventional oils without flaring, and tar sands. Because the volume of tar sands is small, the cumulative volume for each category is divided by its total volume to obtain normalized percent cumulative volume (total volumes for each category are indicated in Fig. 24). Percent normalization allows for a better visual comparison of emission ranges associated with a very small volume (i.e., tar sands) and large cumulative volume (e.g., crude oils with flaring).

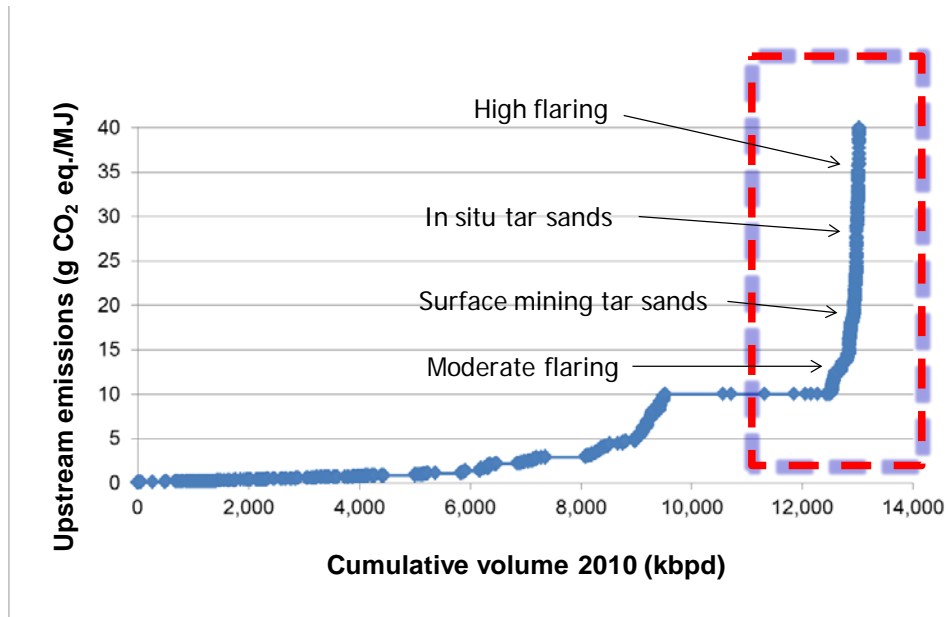


Figure 23. Upstream crude emissions intensities.

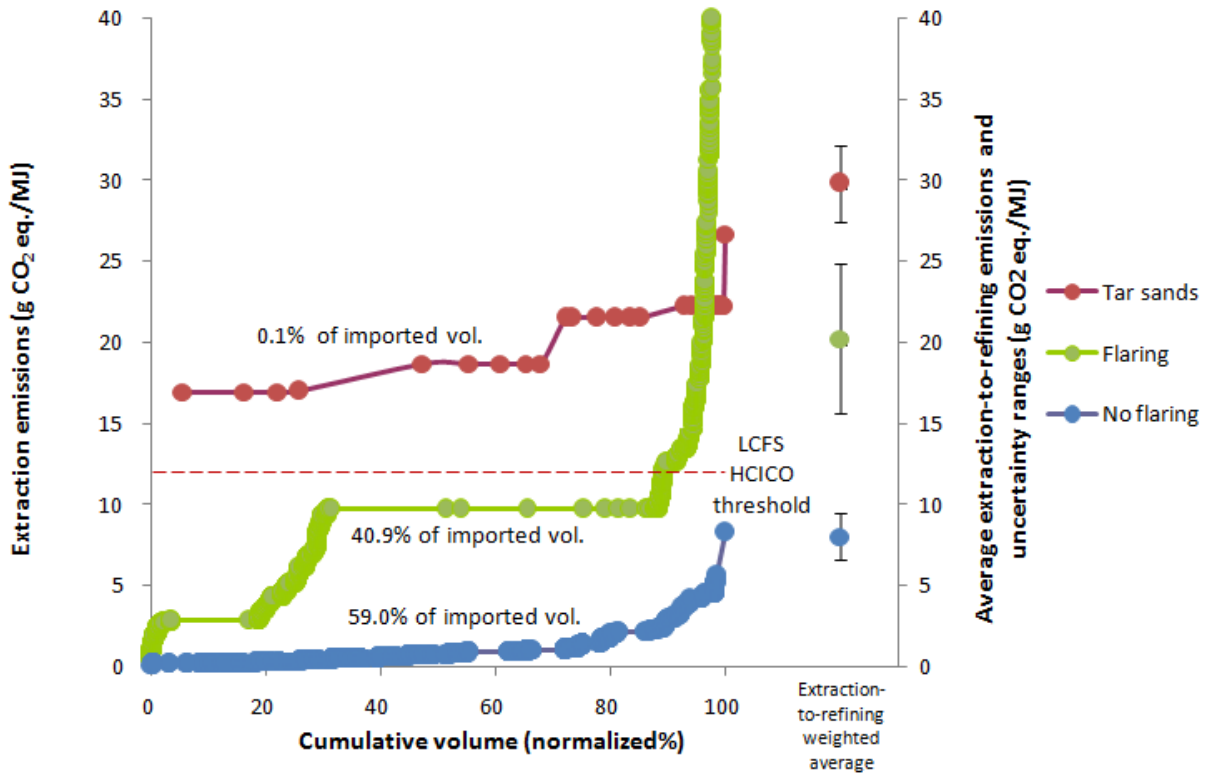


Figure 24. *Left:* Extraction GHG emissions for imported conventional crude oil (with and without flaring) and tar sands. *Right:* Weighted average extraction-to-refining GHG emissions for imported conventional crude oil (with and without flaring) and tar sands, with uncertainty ranges for the average values.

Figure 24 shows that, in general, tar sands oil can have higher GHG emissions than conventional crude, even with flaring, except when volumes of flared gas are particularly large (such as those on the right side of the graph). California's Low Carbon Fuel Standard (LCFS) requires additional reporting for any crude oil with upstream GHG emissions in excess of 15 g CO₂ eq./MJ. Tar sands are one component of a group of new fossil fuel feedstocks typically referred to in the literature as unconventional oil. These unconventional oils include tar sands, shale oil, and extra-heavy oil. Relative to conventional oil, they require more energy-intensive technologies and processes to extract and process crude oil. EIA (2010) projects that about 8% (8.9 MMbbl/d) of the world's oil supply will come from unconventional oil in 2035.

Figure 24 also shows the volume-weighted average of total extraction-to-refining emission for each category of fuel. The averages are assigned uncertainty ranges by considering the minimum and maximum plausible alternative values of key parameters. It can be seen that although flaring emissions in particular are subject to substantial uncertainty, it can still be asserted with confidence that the average emissions from tar sands projects are higher than the average emissions from projects that flare, which are higher than the average emissions from projects that do not flare.

We provide a separate curve focusing only on tar sands projects in Figure 25. Note that this curve uses total production from tar sands, whereas the curve in Figure 24 uses only a proportion of this curve to represent imports into Europe.

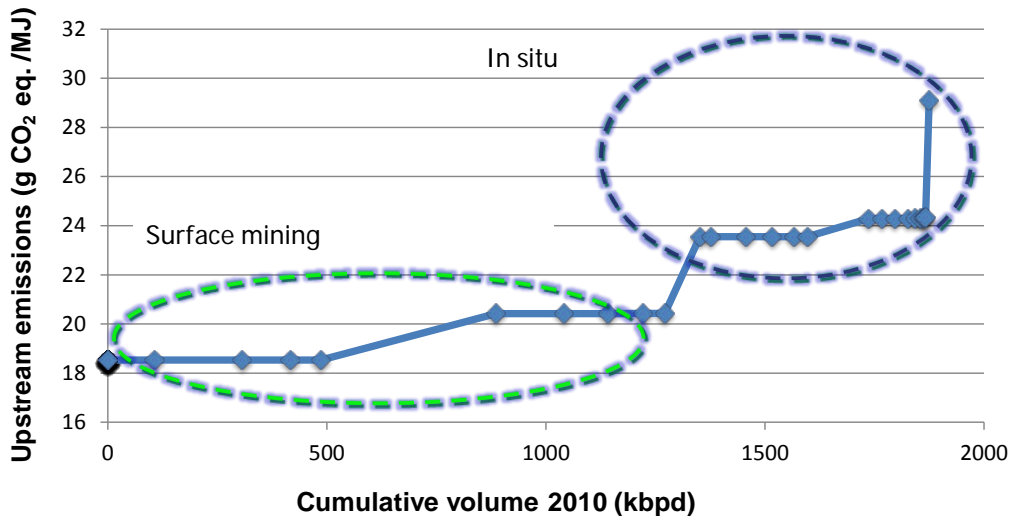


Figure 25. Upstream (extraction) emissions of tar sands.

Further investigation of Figure 23 shows that its shape is essentially caused by the following factors:

- Very low values of upstream emissions are associated with gas fields with some condensate production (high API gravity). Sharing of costs with the gas part of the operation results in an extremely low emission factor. These are not true oil fields, but this condensate is counted as oil production and the condensate is often mixed with the crude. These fields are not flaring, and they are young or immature fields.
- As API gravity falls (i.e., as crudes become heavier) or the maturity of the field increases, the emission factor starts to rise. Note that this area of the curve in Figure 23 is driven by a number of factors including depth, type of development, and onshore versus offshore location (see below).
- As flaring at the field becomes higher, the curve starts to rise rapidly. This rise is associated with GOR, or more accurately, flared gas per barrel and the calorific value of the gas.
- Tar sands emissions start to become important as the curve rises in Figure 23 and can be associated with either surface mining or in situ projects. Surface mining requires less energy for extraction. During 2010, direct crude tar sands imports into Europe were small. It is expected that such imports will grow rapidly in the next 10 years. Although we did not specifically analyze this, imported products from refineries using tar sands would make this volume larger.

Note that although some old flared fields might have emissions intensities higher than those of tar sands, these are associated with fields that are small. Tar sands projects are large. The key here is to focus on large high-intensity projects (i.e., tar sands), not small ones. As tar sands imports into Europe continue to grow, this will become more of an issue (Figs. 26 and 27). Note that production figures are volumes at the field, not imported volumes. In Figure 26 we show crude intensities by volume. Note that tar sands typically are associated with the largest field volumes, other than for flaring fields in such places as Angola and Nigeria.

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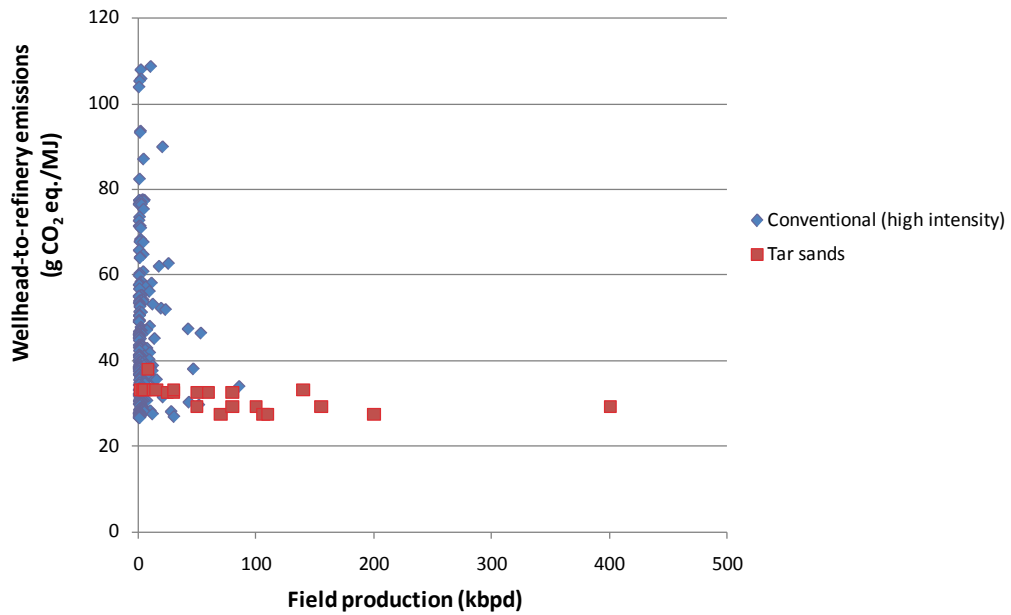


Figure 26. High-intensity crude emissions, from wellhead to refinery output gate, by production (volume).

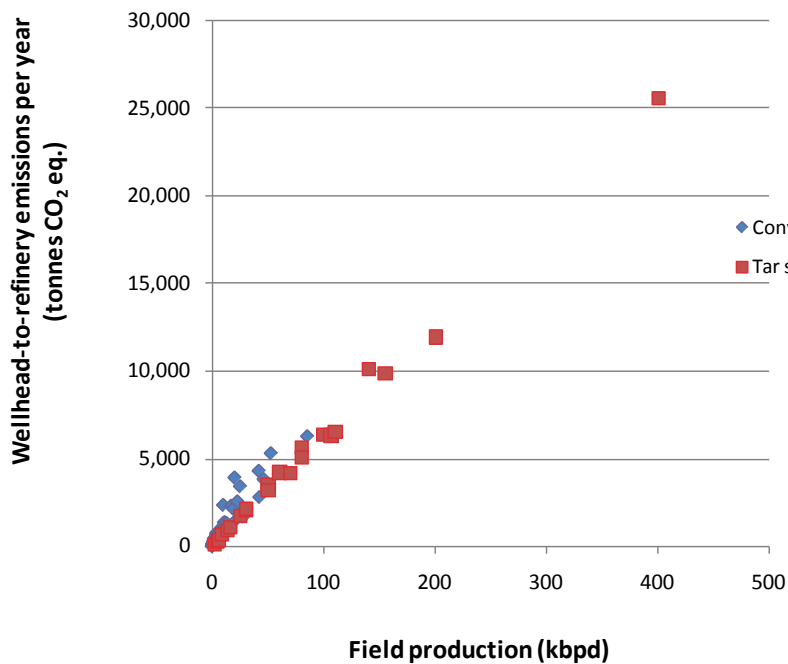


Figure 27. High-intensity crude emissions (upstream).

Very high intensities are usually associated with small fields. We can see this in Figure 27, where we have multiplied the volume by the intensity by the number of days in the year to calculate total yearly emissions.

Distribution of Intensities: Refining and Transportation

Figure 28 shows the marginal emissions associated with transporting this crude to a European refinery and then processing it. This includes the tanker transportation from the producer country terminal (ranging from 0 to 4 g/MJ) and the refining emissions associated with API gravity. The refining emissions range from 3.3 to 8.3 g CO₂ eq./MJ (20 to 50 kg/bbl). The lower level is associated with processing condensates.

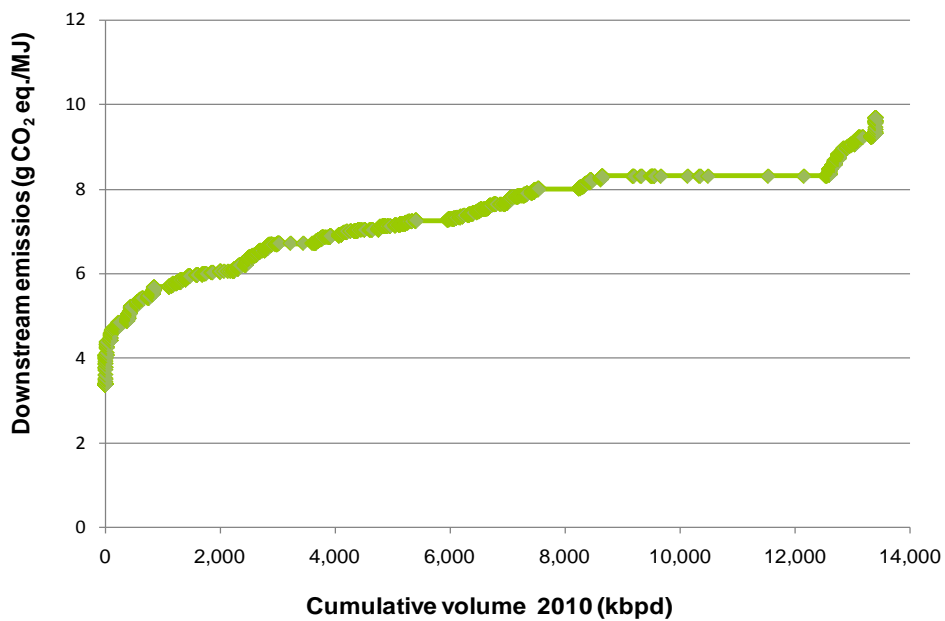


Figure 28. GHG emissions from tanker transportation and refining (downstream).

Distribution of Intensities: Wellhead to Refinery Output Gate

We now combine the two curves (Figs. 23 and 28) to produce a total curve (Fig. 29). Note that Figure 29 reflects a resorting of the data with the total emissions, and the vertical scale does not correspond to those of Figures 27 and 28.

In 2010, projected imports will be about 13 MMbbl/d of crude oil. For discussion purposes, we divide the imported crude into three broad categories based on wellhead-to-refinery output gate GHG emissions per energy content of the fuel (Fig. 29). Nearly half of the 13 MMbbl/d has GHG emissions ranging from 4 to 9 g CO₂ eq./MJ; these are crude oils with little or no flaring of natural gas, minimal fugitive emissions, high API gravities,

and in some cases substantial amounts of oil condensates.²⁶ An equal proportion (6.4 MMbbl/d) has a carbon intensity range of 9 to 19 g CO₂ eq./MJ. Included in this range are crude oils mainly with low API gravities and/or substantial flaring and fugitive emissions and a lack of oil condensates.

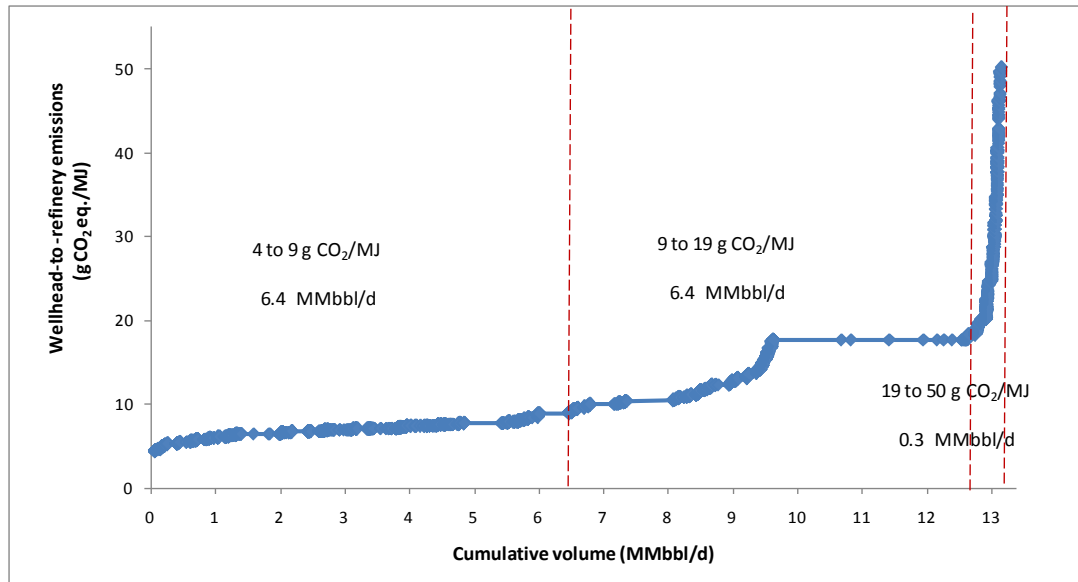


Figure 29. GHG emissions, from wellhead to refinery output gate, associated with imported crude oil.

For the remaining small volume (0.3 MMbbl/d), there is a sharp rise in carbon intensity, ranging from 19 to 50 g CO₂ eq./MJ, contributed by substantial levels of flaring and/or by the exploitation of tar sands. This volume represents an attractive target for GHG reductions. Flaring contributes to GHG emissions in two ways: through CO₂ released during combustion, and through the presence of methane in unburned gas (a result of combustion efficiencies less than 100%). Methane has a global warming potential 25 times that of CO₂. Extraction of tar sands, on the other hand, involves energy-intensive extraction (surface mining and SAGD) and upgrading.

Analysis

Analysis of emissions data on a country basis shows that they can vary widely within a given country. Some fields are flaring whereas others are not, and field characteristics can be different. An excellent example of this is shown in Figure 30 for Nigeria in a region of about 300 miles by 130 miles. Field emissions intensities are

²⁶ Oil condensates are lighter liquid crude oils obtained from reservoirs that mostly contain hydrocarbons in vapor phase. They normally consist of short-chain alkane hydrocarbons. They are easy to clean up.

represented by color, with red representing the highest emission factor. Note the variability in emissions intensity even within this relatively small area.

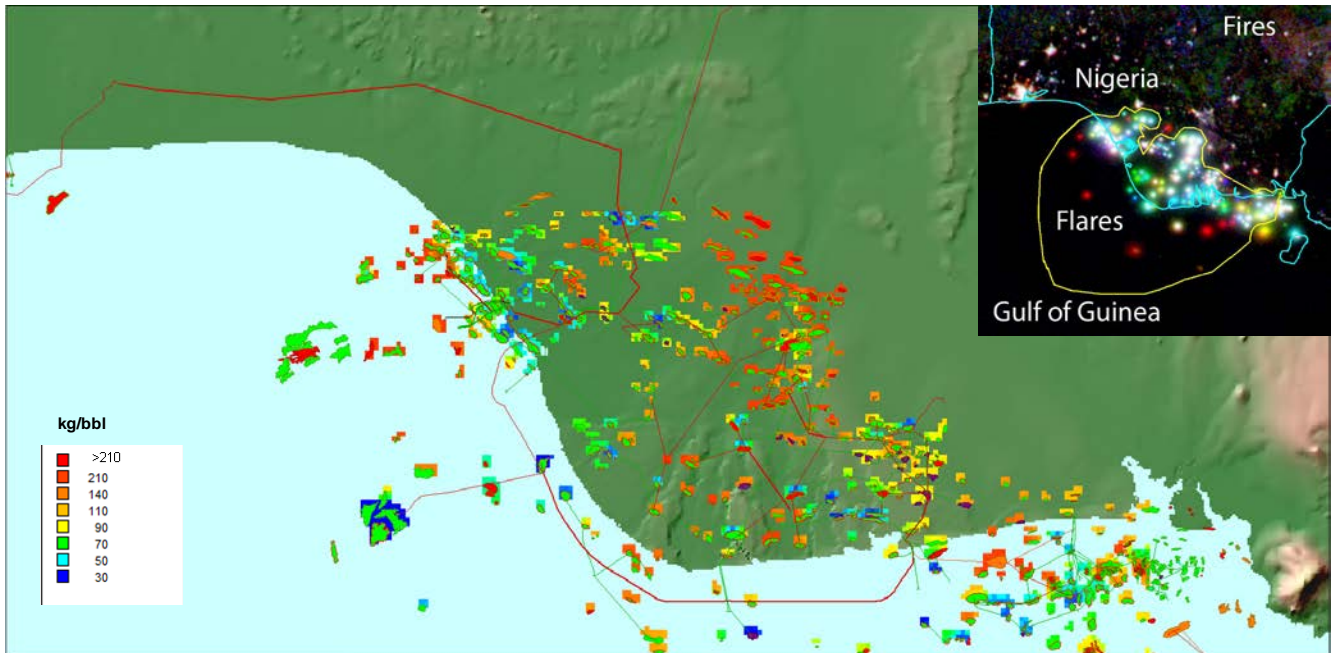


Figure 30. Crude emissions intensities for Nigeria. Inset at upper right is a NOAA satellite image of flares in this region.

On an average basis, the following countries have the highest emission factors. Note that we have excluded countries producing volumes of less than 1000 kbpd.²⁷

- Nigeria (flaring)
- Russia (flaring)
- Canada (tar sands)
- Libya
- Indonesia
- Kazakhstan (flaring)
- Algeria
- Iran
- Iraq

²⁷ Worldwide production.

To illustrate the results of our analysis, we have selected 12 oil fields (Fig. 31). These oil fields show the wide range in wellhead-to-refinery output gate GHG emissions and the relative contributions from five components of the petroleum life cycle considered in this study. Note that the size of each pie chart associated with the oil fields in Figure 31 represents total emissions rather than volume. The selected oil fields encompass a variety of geographic regions, levels of production, levels of flaring, and type of feedstock and development. The oil fields chosen are in North America, South America, Europe, the former Soviet Union, Africa, and Asia. Oil fields of different sizes are included, ranging from 42 kbpd (Dacion, Venezuela) to 5320 kbpd (Ghawar, Saudi Arabia). Some of these oil fields flare (e.g., Kupal, Iran) and some do not (e.g., Bu Attifel, Libya). Flaring is common in countries such as Iran and Russia (Buzcu-Guven, Harriss & Hertzmark, 2010). The oil fields chosen also cover different types of development including onshore, offshore, and tar sands. Oil fields with fugitive emissions ranging from 0.02 g CO₂ eq./MJ (Mad Dog, USA) to 3.9 g CO₂ eq./MJ (Dacion, Venezuela, which produces heavy crude) are included.

Emissions vary by a factor of 5 across the representative oil fields in Figure 31. In Canada, the difference between emissions at Steepbank and Hibernia shows the effect on emissions of the additional energy needed to extract tar sands. The tar sands field (Steepbank) has four times the emissions of a conventional oil field (Hibernia). An oil field with high levels of flaring (e.g., Kupal) can have GHG emissions comparable to or higher than those of tar sands (e.g., Steepbank). For conventional crudes with minimal flaring, it is the refining step that contributes most to emissions from the wellhead to the refinery output gate. The highest potential GHG reduction opportunities for these crudes are likely to be at the refinery. Note that in this analysis, energy use and GHG emissions in refining vary only by API gravity.

These 12 oil fields can be grouped into three categories by emissions level to analyze the relationship between key parameters and GHG emissions from the wellhead to the refinery output gate. We refer to these as low-intensity, medium-intensity, and high-intensity oil fields.

Low-intensity oil fields (6 to 8 g CO₂ eq./MJ) include Mad Dog and Bu Attifel; they are characterized by little or no flaring and fugitive emissions and high API gravity (light crude oils). As a result of high API gravity, refining emissions are also low. Although refining emissions are small, they still constitute the major portion of GHG emissions from the wellhead to the refinery output gate. This is because less energy is required for crude oil extraction. Extraction emissions are typically a function of GOR, age of oil field, reservoir depth, pressure, viscosity, API gravity, and type of development/feedstock. Some of these parameters are correlated. The extraction phase is a relatively minor source of upstream emissions for these fields.

Medium-intensity oil fields (12 to 15 g CO₂ eq./MJ) include Duri, Samotlor and Cantarell. Their emissions from the wellhead to the refinery output gate are larger because of higher contributions from either flaring or fugitive emissions. For example, Duri has fugitive emissions of 2.7 g CO₂ eq./MJ and flaring emissions of 2.0

g CO₂ eq./MJ. Likewise, Samotlor has flaring emissions of 3.1 g CO₂ eq./MJ. Crude oils produced in Duri and Cantarell are heavy (low API gravity, <26), which contributes to relatively higher refinery emissions. Duri uses an energy-intensive steam-flooding technique to extract crude oil, resulting in substantial emissions from extraction.

High-intensity oil fields (22 to 31 g CO₂ eq./MJ) either have higher flaring and venting or produce unconventional crude oil. For example, Kupal and Dacion have higher extraction-to-refining emissions due to substantial flaring and venting. Steepbank, on the other hand, is a tar sands project, which requires more energy for extracting bitumen and upgrading it to synthetic crude oil. Refining emissions for Dacion and Steepbank are higher because they produce heavy crude oils (API gravity <26).

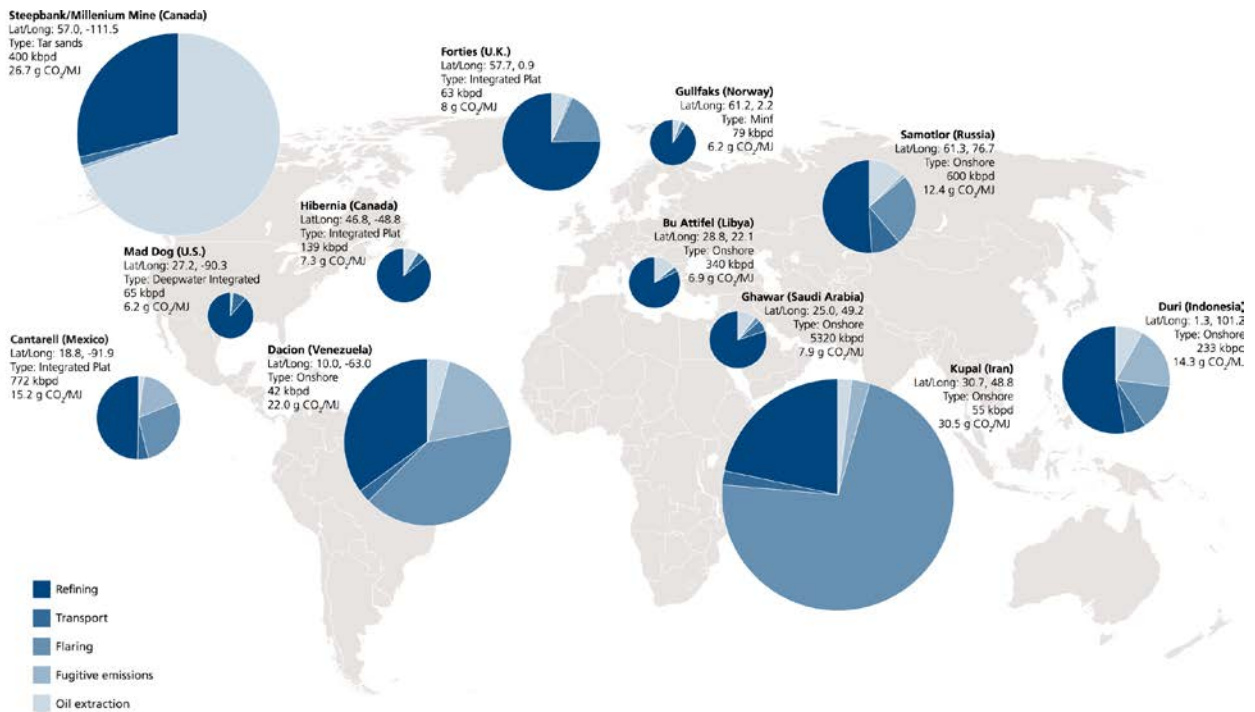


Figure 31. GHG emissions, from wellhead to refinery output gate, for representative oil fields worldwide.

Emissions by Product

Earlier we described how we allocated the emissions on an end-product basis. We now show the results of this approach in the form of emission factors by product. This is shown in Figure 32 for 2010. Similar curves are seen for the years 2015 and 2020 but are omitted for brevity.

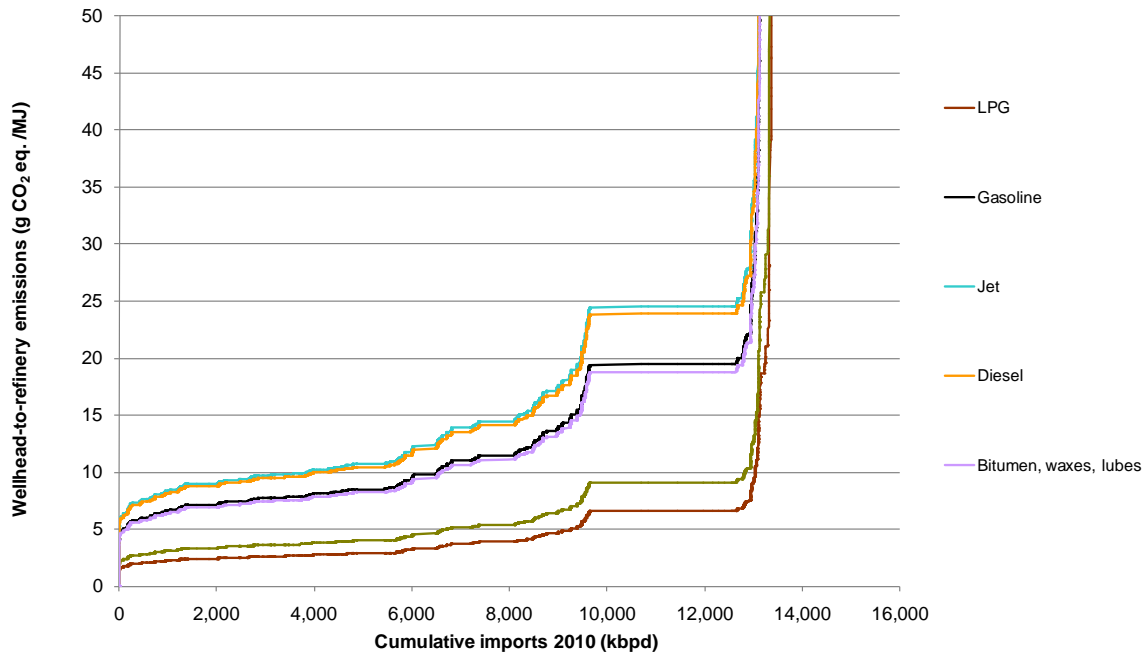


Figure 32. Emissions intensities, from wellhead to refinery output gate, for petroleum co-products (European imports, 2010).

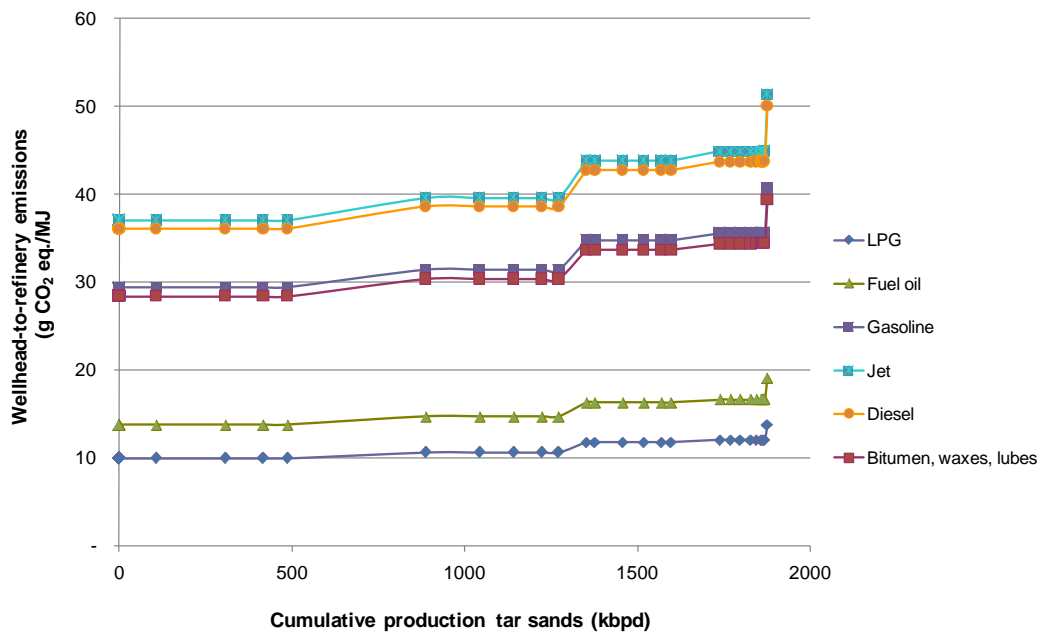


Figure 33. Emissions intensities, from wellhead to refinery output gate, for petroleum co-products for tar sands (2010).

For comparison purposes, we show in Figure 33 the petroleum co-product derived from tar sands only. Note that this value reflects full production from the fields. Canadian exports to Europe were less than 50 kbpd in 2008.

The volume-weighted average values of these curves are shown in Figure 34 for 2010 and then for the three spot years (2010, 2015, 2020) in Figure 35. Note that the tar sands emissions (Fig. 34) are on average some 150% higher than the average imports.

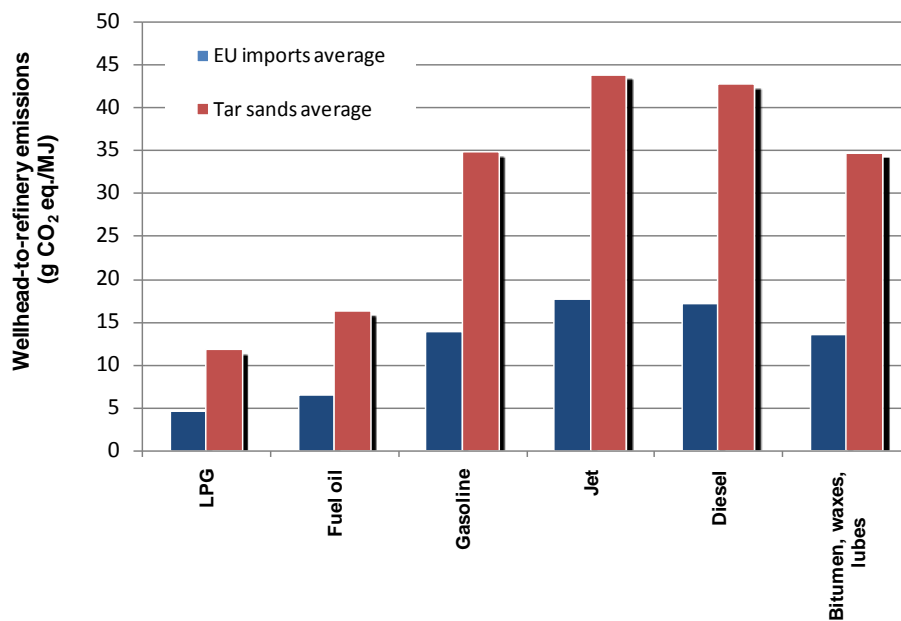


Figure 34. Average end-product emissions intensities in 2010.

The average emission factor for Europe increases through time from 13.0 g CO₂ eq./MJ to 13.9 g CO₂ eq./MJ from 2010 to 2020, a 7% increase in intensity.²⁸ The upstream portion of this rises from 5.8 g CO₂ eq./MJ to 6.9

²⁸ Assumes no intervention. This represents an increase from 77.8 kg CO₂ eq./bbl to 83.4 kg CO₂ eq./bbl from 2010 to 2020.

g CO₂ eq./MJ, an 18% increase.²⁹ Because our methodology uses a constant allocation, we also see a 7% increase in end product emissions across time. The end product values shown below are based on our assumptions about European refineries. Changes in these assumptions could change these values by 5 to 65%.³⁰

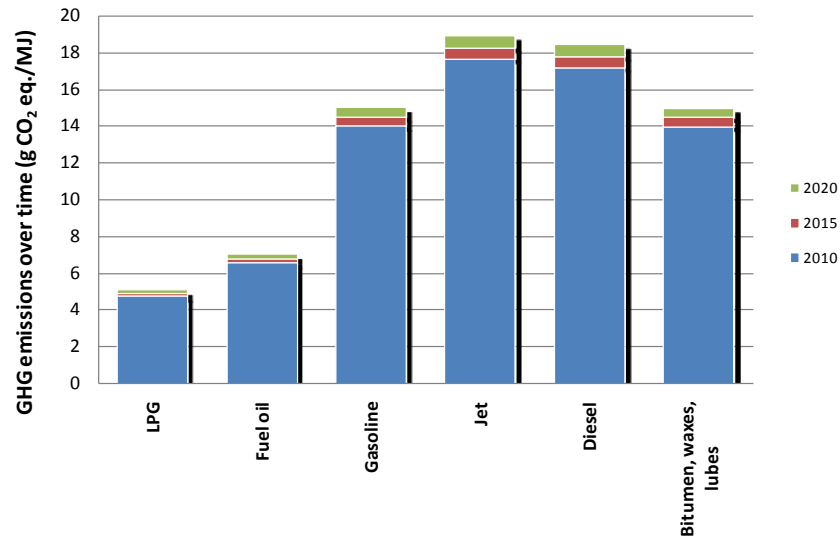


Figure 35. Wellhead-to-refinery output gate GHG emissions of end-products through time (all fields).

As oil extraction becomes more difficult, companies are forced to exploit deeper reservoirs, explore deeper waters, and tap into emission-intensive sources such as tar sands. Some of these deeper-water sources, such as Angola, are associated with high levels of flaring. As this production source grows through time, so will average emissions intensities, unless carbon is captured or reduced in some way.

²⁹ Our methodology does not account for changes in refining emissions through time. For example, does an older refinery produce more emissions with the same crude slate? These figures are for a straight run versus an energy-based allocation.

³⁰ Based on Energy-Redefined LLC's calculations on some different refinery setups; will vary according to end product.

3.2 Cluster Analysis of Emissions Intensities

In the diagrams that follow (Figs. 36 and 37), we show a sample of the extensive analysis that was carried out on the data generated from our models. We found from this analysis that it is difficult to find simple algorithms or rules that correlate with the default values calculated with our methodology. This is not surprising, given that many variables interact to produce crude intensities.

Clustering by Emissions Level

Using cluster and categorization techniques, we found that the emissions data naturally fall into 8 to 10 clusters, but they do not cluster according to country or along other obvious lines.

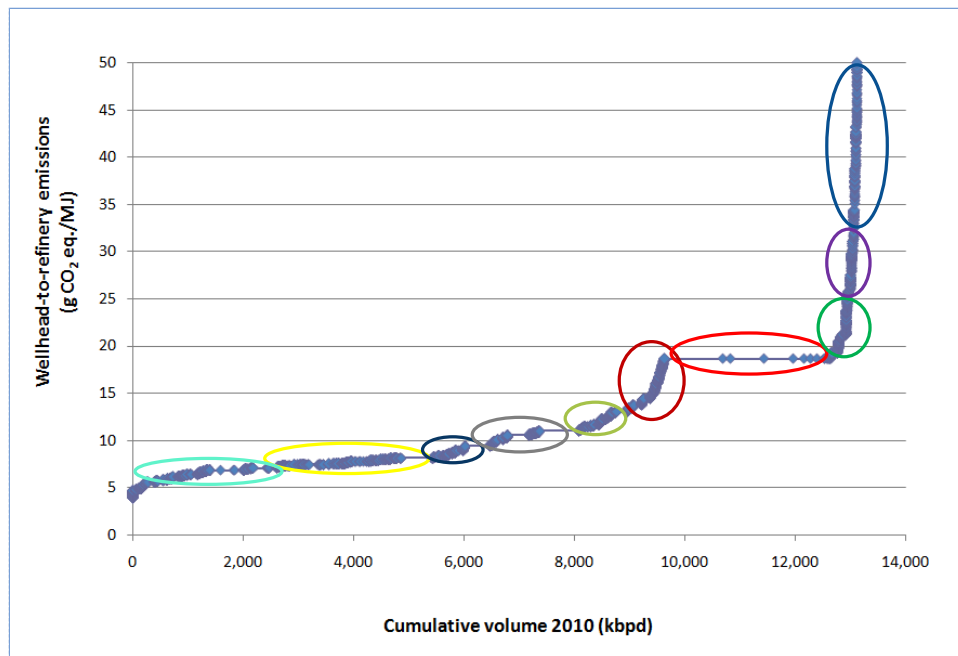


Figure 36. Clustering by emissions level.

For clustering, we focused on an analysis of upstream emissions because we have already made the assumption that refining emissions are a function of API gravity.

Regression tree analysis of these data shows that we can predict default values with a deep and complex decision tree with more than 300 terminal nodes.³¹ We show an example of the output from such an analysis in Figure 37.

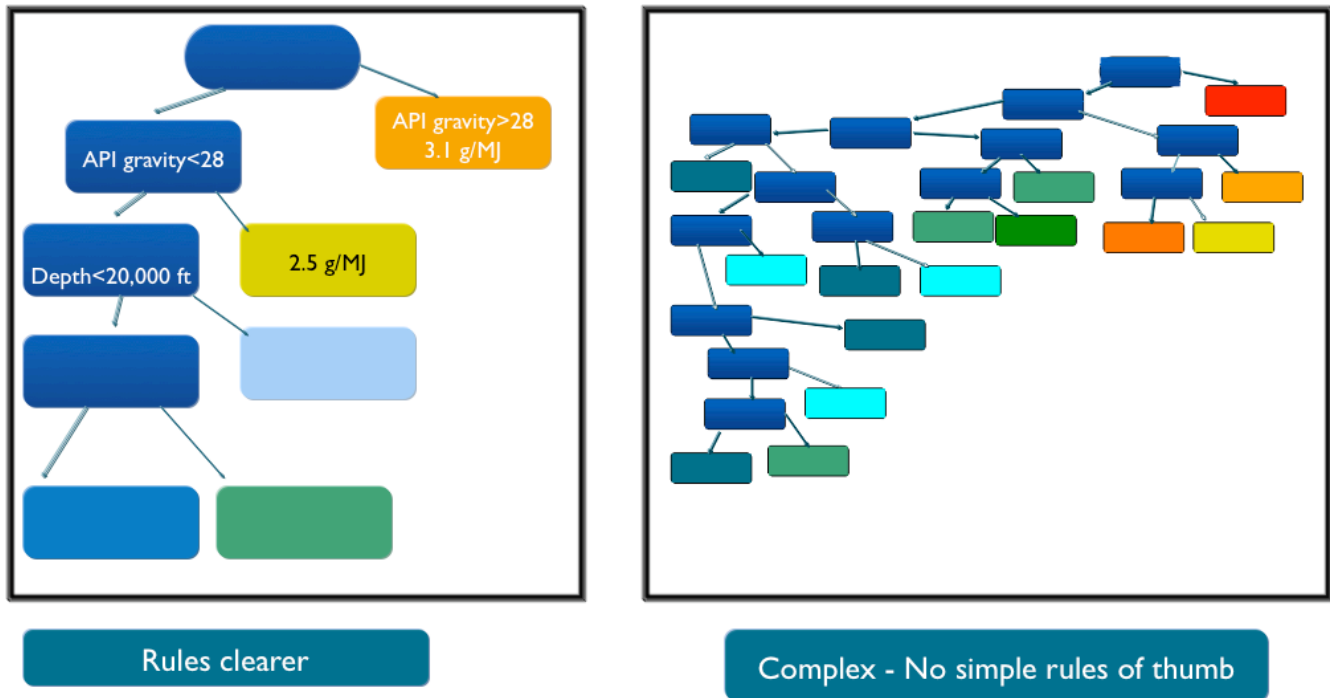


Figure 37. Regression tree output (hypothetical example).

We can predict default values with a high degree of accuracy using complex trees. Simpler trees end up misspecifying the default values with a 25 to 50% error in some cases.

Within particular clusters in Figure 36, we can predict reasonably well some default values. It is possible to predict values for fields in certain ranges with API gravity and depth.

³¹ This decision tree is based on classification and regression tree (CART) analysis. If API gravity is >28 and depth is >3500 ft, then the default value is cluster level 1. This tree is more than 20 levels deep.

What Sort of Relationships Can We Use to Predict Default Values?

In the higher-intensity crudes (>8 g CO₂ eq./MJ upstream, excluding tar sands), there is a clear trend with the amount of flaring per barrel of oil produced (Fig. 38).

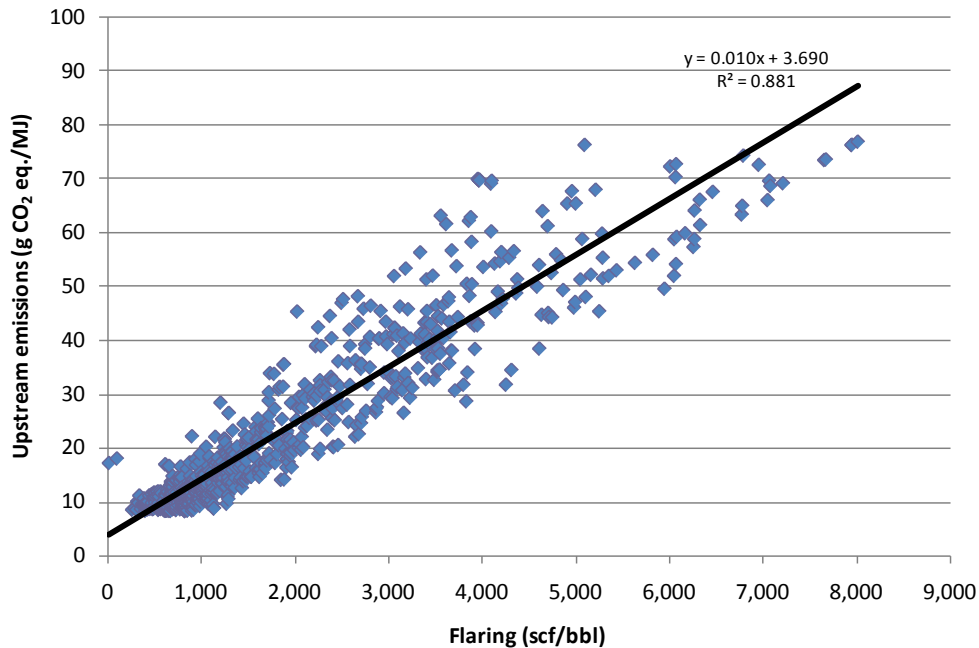


Figure 38. Relationship between upstream emissions and flaring.

Although there is a substantial error band around the trend, especially for flares with an intensity around 4 mmscfd (4 kbpd), this can be explained when the BTU content [calorific value (CV)] of the gas is included in the data. Essentially there are many straight-line relationships if the BTU content of the gas is held constant. The colors of the data in Figure 39 represent different levels of BTU content. Note that the slopes of these lines are different.

In the lower-intensity crudes (i.e., below 8 g CO₂ eq./MJ upstream), we find a more complicated relationship (Fig. 40). It appears that there might be some relationship between API gravity and emissions intensity. It is not surprising that for crudes with an API gravity less than 20 to 25, crude emissions intensities grow rapidly as API gravity decreases. These crudes may require additional processing at the well site. But this is not the whole story, as clearly evidenced by the spread around the trend lines. Some of these fields have high venting associated with them, some are older, and some are flaring.

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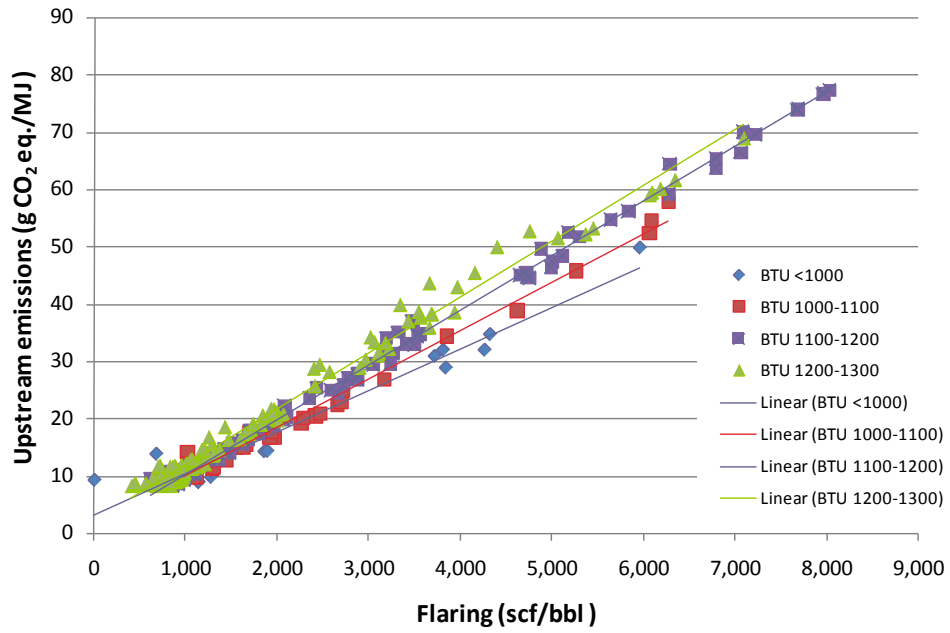


Figure 39. Relationship between upstream emissions and flaring with BTU content.

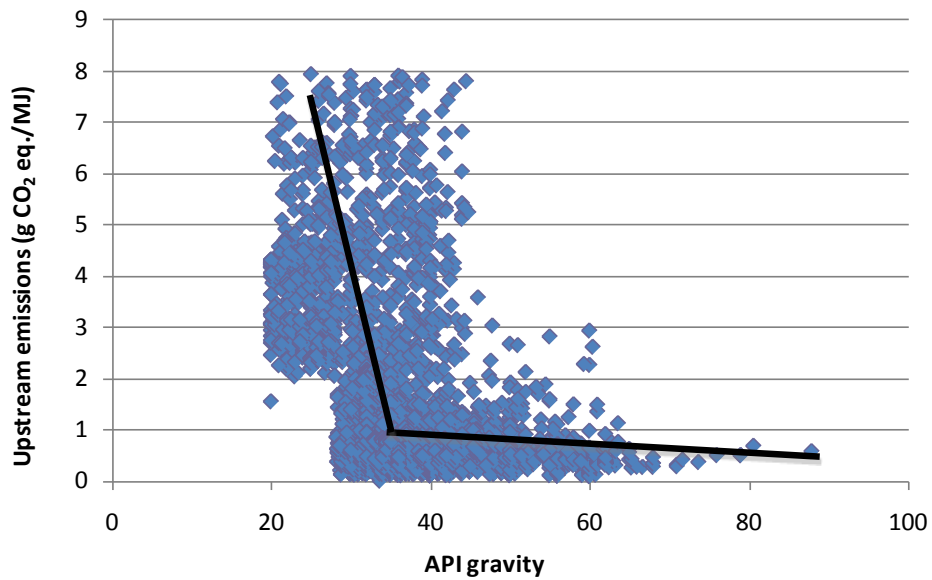


Figure 40. Relationship between upstream emissions and API gravity.

We now split the data again by API gravity and show graphs for fields with API gravities above 30. Figure 41 plots emissions intensities against production start year.

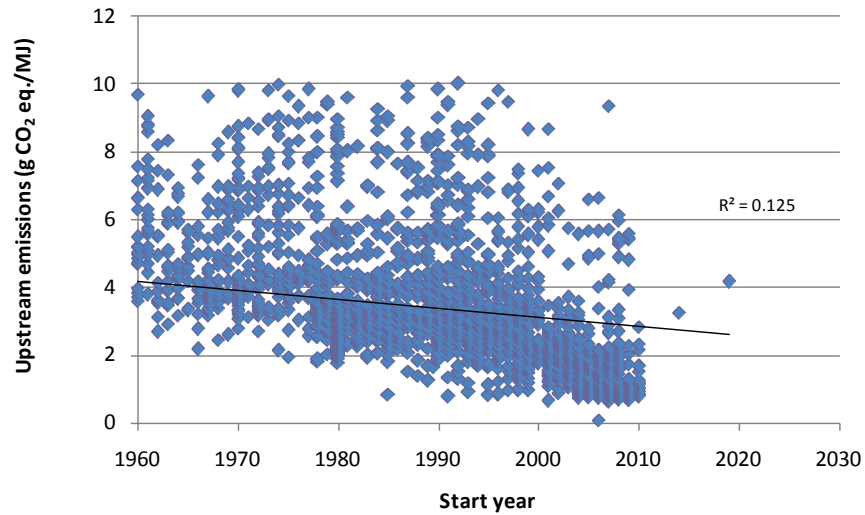


Figure 41. Relationship between upstream emissions and start year (API gravity ≥ 30).

Clearly there is some start-year dimension, but again it doesn't tell the whole story. Figure 42 shows the same data plotted against reservoir depth.

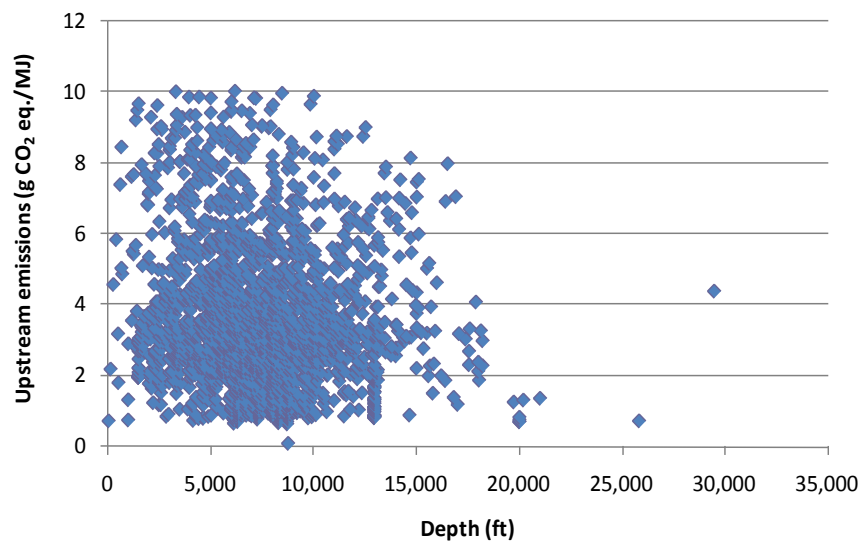


Figure 42. Relationship between upstream emissions and depth (API gravity ≥ 30).

Again, it is difficult to discern any clear relationship. Similar graphs for fields with API gravities below 30 show that it is difficult to find simple trends or relationships.

Detailed Relationships

Further investigations of emissions intensity with a variety of drivers, using neural nets and other advanced statistical techniques, reveal similar relationships, but the interaction of the variables is complex.

Many factors drive the level of crude emissions intensity, including but not limited to:

- Level of flaring (dependent on GOR and availability of nearby infrastructure)
- API gravity
- Reservoir depth
- Start year
- Development type (e.g., tar sands, floating platform, etc.)

3.3 Sensitivity Analysis

As already noted, we have made some assumptions in producing this analysis and output. What if the assumptions were different? Here, we investigate three categories of fields³² with low, medium, and high emissions intensity and look at the effect of the following key assumptions:

- Flaring default value: standard assumption (Canadian 2.3 CO₂ eq. kg/m³ emissions) versus ours, based on gas specification
- GOR increased by 10%
- Efficiency increased by 5%
- Production increased by 10%
- Flare tip efficiency reduced by 5% (note that we are already assuming 98% efficiency; we believe that in reality many flares are at efficiencies well below this value)
- Refining allocation: straight run versus processing energy (our base case)
- Refining emissions reduced by 10%
- Venting reduced by 10%

³² Same three fields as shown in Figure 22.

To normalize the results, we have set all transportation emissions to an average figure of 0.8 g CO₂ eq./MJ. We show our results in the graphs below, which represent the percent change over the base case. Note that the low-intensity field has no flaring associated with it, so it does not exhibit any sensitivity to GOR or flaring (Fig. 43).

Figure 43 shows the percent change in emissions over the base case and reflects the emissions for the crude.

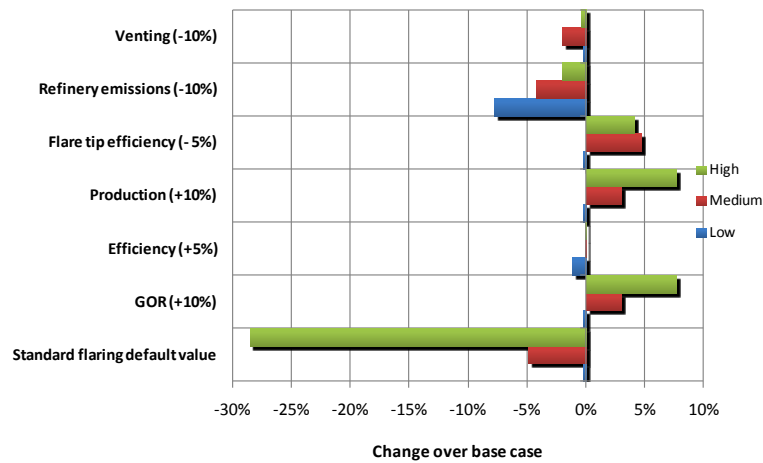


Figure 43. Sensitivity to crude emissions intensity (g CO₂ eq./MJ): Percent change in three example cases.

Note that because end-product allocations are assumed to be constant in this analysis, the sensitivity graph for end products will be the same as Figure 43. In practice, this may not be the case.

There are also notable differences between crudes with high and low emissions intensities. This is partly due to the differences in importance of the various variables in the makeup of the final emission number. For example, in the case of the high-intensity crude, refining represents around 20 to 25% of the total intensity. Hence, a 10% reduction in flaring emissions at the refinery results in a 2 to 3% drop in the overall number. Although this graph shows an effect from the increase in production, we could have picked other examples where this was not the case. This is partly because the examples we chose were for newer fields and required a step jump in need for more utilities. Our model assumes that utilities are added in lumps or discrete units.

Interestingly, we found that where fields are flaring, little benefit is seen from increases in efficiency. This is because a higher efficiency means that less gas is required to run the plant at the field, meaning that more gas is available to be flared. At least in the cases we have looked at, it appears that the two effects nearly cancel

each other out. This result seems to suggest that it doesn't matter what assumption we make about efficiency at the plant if a field is flaring.

Other conclusions can be drawn from Figure 43:

- A Canadian-type default value of 2.3 kg/bbl could result in a 25 to 30% reduction in emissions intensity values for high-intensity crudes. Note that the base case uses values estimated from gas compositions.
- A flare with 93% efficiency could result in about 5% more emissions than calculated. Some open-pipe flares could have efficiencies considerably less than this.

Allocation of petroleum refinery energy use (and the resultant emissions) among different products is needed in carbon emissions analyses to evaluate various transportation fuels. In such analyses, energy use and emissions from a refinery are usually allocated to individual fuels, so that fuel-cycle energy use and emissions for producing a given fuel can be evaluated. The allocation can be based on a number of methods, including but not limited to mass, volume energy content, market value share, and apportioning the emissions according to "actual process use." An aggregate or straight-allocation approach, which allocates total energy use and emissions at the refinery plant level, is essentially one that assumes that equal energy is expended during refining of all fuel product slates. This approach is unable to account for the energy use and emission differences associated with producing individual fuels in separate refining processes within a refinery. Consequently, results based on aggregate allocation suffer from their insensitivity to the changes in individual refining processes used to produce different mixes of refinery products, such as increases in diesel production.

Figure 44 shows the effect of allocation methods on product CO₂ emissions intensities for an average European refinery. Our base-case allocation was based on calculation of processing energy requirements, as described above. We compare this with the aggregate straight-line approach (i.e., products treated equally) that was discussed within the EU earlier in the FQD process.

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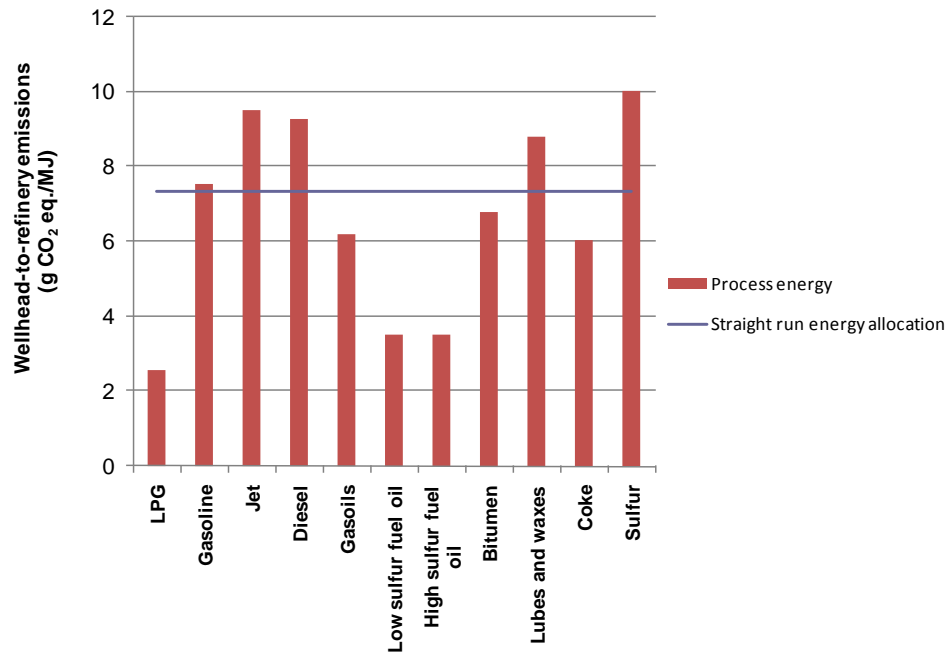


Figure 44. Sensitivity to allocation methodology for an average European refinery.

Note that the differences between these two allocation approaches range from 3 to 65%, depending on end product.

4. Summary

To summarize, we have shown:

- GHG emissions from the wellhead to the refinery output gate can range from 4 to 50 g CO₂ eq./MJ for crude oils imported to Europe.
- There is not much variation among the vast majority of the volumes imported to Europe, although a small number of worst-practice cases have high emissions.
- Crude intensity default values vary widely, even within individual countries.
- Accurate default values cannot easily be determined with simple rules or algorithms.
- Fields that are flaring or are tar sands-based produce the highest-intensity crudes.
- GOR (or more accurately, flared volume per barrel) is a good predictor of emissions intensity for flared fields.
- There is a lack of detailed data/transparency on tar sands projects.
- The average emissions intensity for upstream projects (tied to imports into the EU) will rise by about 18% between 2010 and 2020.
- The average emissions intensity from the wellhead to the refinery output gate (tied to imports into the EU) will rise by about 7% between 2010 and 2020.
- With the exception of smaller volumes with high levels of flaring, tar sands-derived oil has greater upstream CO₂ equivalent emissions than conventional crude oil, even when flaring and venting are considered.

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APPENDIX

Crude Intensities for Europe, Including EU Member States' Internal Production

The analysis of the main report focuses on the crudes imported into EU member states. Our results are little changed by the addition of internal production within EU member states.

Norway and the United Kingdom are major exporters of their crude. About 50% of this crude is destined for other areas around the world. Europe currently produces around 4000 to 4500 kbpd and exports about 2000 kbpd, leaving about 2500 kbpd within the EU. The United Kingdom and Norway combined produce 3800 kbpd. Exports of European crude to other parts of the world are summarized in Figure A1, derived from the 2009 BP Statistical Review of World Energy.

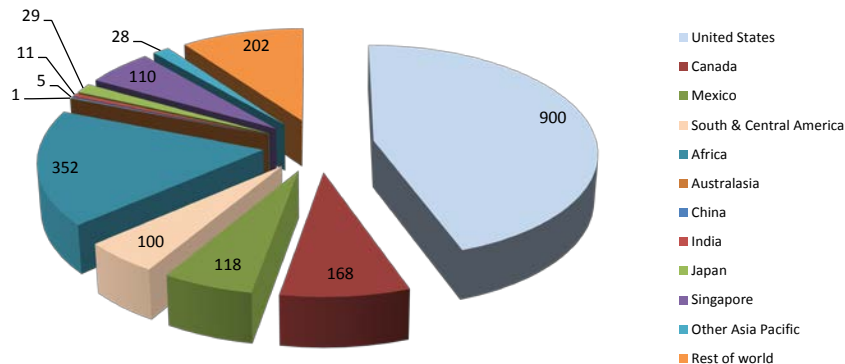


Figure A1. European crude oil exports distribution (kbpd).

Figure A2 shows the total emissions for both the imported and internal production combined. We show this against the curve shown in the main part of the document, which is for imported crudes only. Although the curves are similar, the lower-intensity part of the curve is extended to the right. This is not unexpected, as most of the production in the United Kingdom and Norway comes under strict flaring rules.

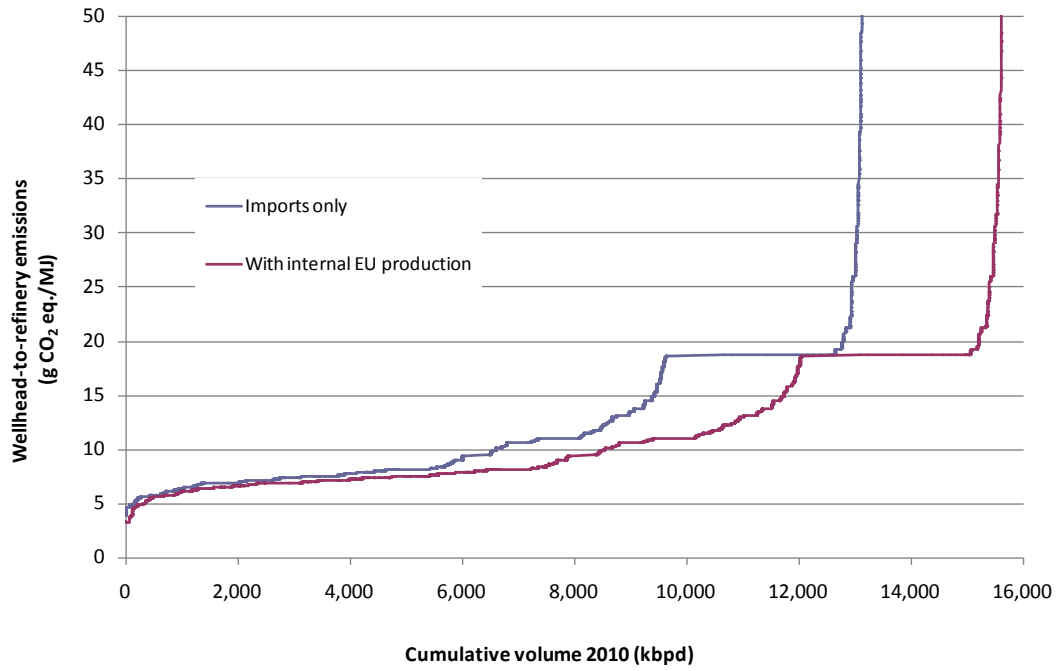


Figure A2. Wellhead-to-refinery output gate GHG emissions of imported crude oil and EU oil production.

Note that the weighted average emission factor is some 6% lower if internal EU production is included.