CDP Technical Note: Guidance methodology for estimation of Scope 3 category 11 emissions for oil and gas companies

CDP Climate Change Questionnaire

Contents

Version

Version	Revision date	Revision summary
1.0	2018	First published version.
1.1	April 6, 2020	“Industry and company structure” section revised, and minor update to “Introduction” section to align with the 2020 CDP climate change questionnaire.
1.2	January 7, 2021	Minor editorial changes
2.0	January 21, 2022	Additional guidance for companies responsible for the transportation (including maritime), storage, transmission, and distribution of fossil fuels, including calculating scope 3 category 11 emissions based on throughput.

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Nomenclature and units

A	Upstream sale
AX	Upstream sale from own upstream production (X)
API	American Petroleum Institute (gravity)
B	Downstream sale
bbl	Barrels
bcf	Billion cubic feet
boe	Barrels of oil equivalent
boed	Barrels of oil equivalent per day
bpd	Barrels per day
Btu	British thermal units
C	Carbon content
cf	Cubic feet
EF	Emission factor
EF^c	Full combustion emission factor
EF^{ce}	Full combustion energy emission factor
ES3.11	Scope 3 category 11 emissions
EO	Effective oxidation rate
F	Downstream feedstock
FX	Downstream feedstock (F) from own upstream production (X)
gal.	Gallons (US)
Gg	Giga-grams
GJ	Gigajoule
GR	Gas ratio (CO_2e/CO_2)
GWP	Global Warming Potential
HV	Heating value
i	Upstream company (E&P) system boundary
ii	Downstream company (refiner/processor) system boundary
iii	Integrated company system boundary
kg	Kilograms
m^3	Cubic meter
mbpd	Thousand barrels per day
mmbbl	Million barrels
mmcm	Million cubic meters
NEU	Non-energy use (portion of output for NEU)
OF	Oxidation factor
P	Net production
p	Product
S	Sales
SC	Sulfur content
SF	NEU storage fraction
SG	Specific gravity
t	Ton (metric ton)
tCO_2e	Tons of carbon dioxide equivalent
TJ	Terajoule
toe	Tons of oil equivalent
X	Upstream net production
Y	Downstream net production
ρ	Density

1. Introduction

Fossil fuel combustion releases carbon dioxide (CO_2) and is the principal source of anthropogenic greenhouse gas (GHG) emissions worldwide [1]. These emissions result primarily from the use of coal, oil and gas products. The WRI/WBCSD Greenhouse Gas Protocol [2] sets the standard for reporting direct company emissions (Scope 1), indirect emissions deriving from purchased energy carriers (Scope 2), and value chain emissions (Scope 3). Scope 3 encompasses 15 distinct categories covering all emissions along the corporate value chain. The use of sold products falls under category 11 of Scope 3 and typically represents over 90%[1] of total emissions relating to oil and gas companies.

Company accountability for Scope 3 emissions is less obvious than for Scopes 1 or 2 and, without direct control over value chain activities, companies are less likely to estimate them as accurately or as consistently. This document is a guide for standardizing the estimation of Scope 3 category 11 emissions from oil and gas companies. The methodology described herein will assist company analysts in improving the quality, transparency, and consistency of Scope 3 emissions reporting and disclosure to CDP.

Typically, a company will begin its GHG inventory by calculating its Scope 1 and 2 emissions; these direct and indirect emissions are not covered by this methodology. Similarly, guidance on calculating emissions related to other Scope 3 categories has been excluded. Many oil and gas producing companies have additional business activities in other industries, some of which may also result in category 11 emissions. Company analysts are advised to consult GHG Protocol guidance on Scope 3 reporting [3-4] for approaches to quantifying a company's full emissions inventory.

The GHG accounting questions in CDP's climate change questionnaire are aligned with the GHG Protocol. Corporate Scope 3 emissions should be reported under question C6.5. Column 1 of the table question ("Scope 3 category") are directly related to the GHG Protocol Scope 3 categories.

Established under the GHG Protocol is a set of reporting principles: relevance, completeness, consistency, transparency, and accuracy [2, p.6]. These principles form the wider context within which this methodology is applicable. The International Petroleum Industry Environmental Conservation Association (IPIECA) also provides detailed guidance on emissions reporting for the oil and gas industry [5]. This guidance is acknowledged and should complement the proposed methodology.

[1] Based on analysis of 2015 company disclosures to CDP

2. Boundaries

The boundaries stated in this section are based on the reporting guidance of the GHG Protocol [2-4]. Where appropriate, they have been customized to reflect the characteristics of the oil and gas industry.

2.1 Organizational

Organizational boundaries refer to assets that fall inside the company inventory boundary and the attribution of emissions from those assets to the company. Company operations are variable in their legal and operational structures [2, p.16]. Company operations may be wholly owned, incorporated or non-incorporated, joint ventures, subsidiaries, and so on. Consolidating GHG emissions for corporate reporting has two separate approaches: equity share and control. Where a company has joint ownership with a nation state, the same consolidation rules apply as with private/private partnerships. For the equity share approach, emissions are attributed according to the share of equity the company has in an operation. Equity is measured by the company's economic interest in the operational asset, which is the company's right to the asset's risks and rewards. Typically, this share aligns with the company's percentage ownership of the asset. Where this is not the case, the economic substance of the relationship takes precedence over the legal ownership form so that equity share reflects the economic interest [2]. The analyst preparing the emissions estimation may therefore need to consult the company's accounting or legal staff to ensure the appropriate equity share is applied.

For the control approach, emissions are fully attributed to the company that has control and are not attributed if the company has an interest but no control. Control is defined as financial or operational[2]. The definitions of control are detailed in the GHG Protocol [2, p.16-23] and, specifically for oil and gas companies, in IPIECA industry guidelines [5]. Whichever the applied approach, the choice should be consistent throughout organizational levels and between partner organizations.

2.2 Operational

Operational boundaries refer to emission scopes and are categorized as direct or indirect relative to the organizational boundary. Fifteen reporting categories of Scope 3 emissions are defined under the GHG Protocol. These are represented in Figure 1 alongside Scope 1 and Scope 2 [3, p.31]. The six greenhouse gases agreed under the Kyoto Protocol are included.

Scope 1 emissions are direct GHG emissions from sources owned or controlled by the company. Scope 2 emissions are indirect GHG emissions and derive from the generation of electricity, steam, heating and cooling purchased by the company for its own consumption. Scope 3 emissions are all indirect GHG emissions other than those identified for Scope 2. Indirect emissions are from activities linked to the company but not owned or controlled by the company. Scope 3 categories cover the full life cycle of a product's emissions including steps before and after the product's position in the cycle.

Category 11 'use of sold products' relates to direct use-phase emissions of sold products and services over the expected product lifetime [3, p.48, 4, p.113]. GHG Protocol guidance on Scope 3 emissions reporting [3-4] identifies three general sources of category 11 emissions: those related to a product's direct energy demand; those occurring from the product's use as a fuel or feedstock; and, those that relate to other forms of GHG emission during use. The products sold by oil and gas companies are relevant only to the second of these three sources. The use-phase lasts until the

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[2] Operational control defines an organizational boundary and should not be confused with operational boundaries, which are the subject of section 2.2.

product is finally depleted, or disposed of, after which any further emission falls under category 12 'end-of-life treatment of sold products'.

Priority is given to category 11 because it typically represents over 90% of all GHG emissions (Scopes 1-3) relating to the oil and gas industry.

2.3 Temporal

Temporal boundaries are defined here as relating to the period over which the company reports emissions and the consideration of emissions over time. Companies disclose their emissions to CDP on an annual basis and should specify their reporting period. Companies need only disclose Scope 3 emissions for the reporting year.

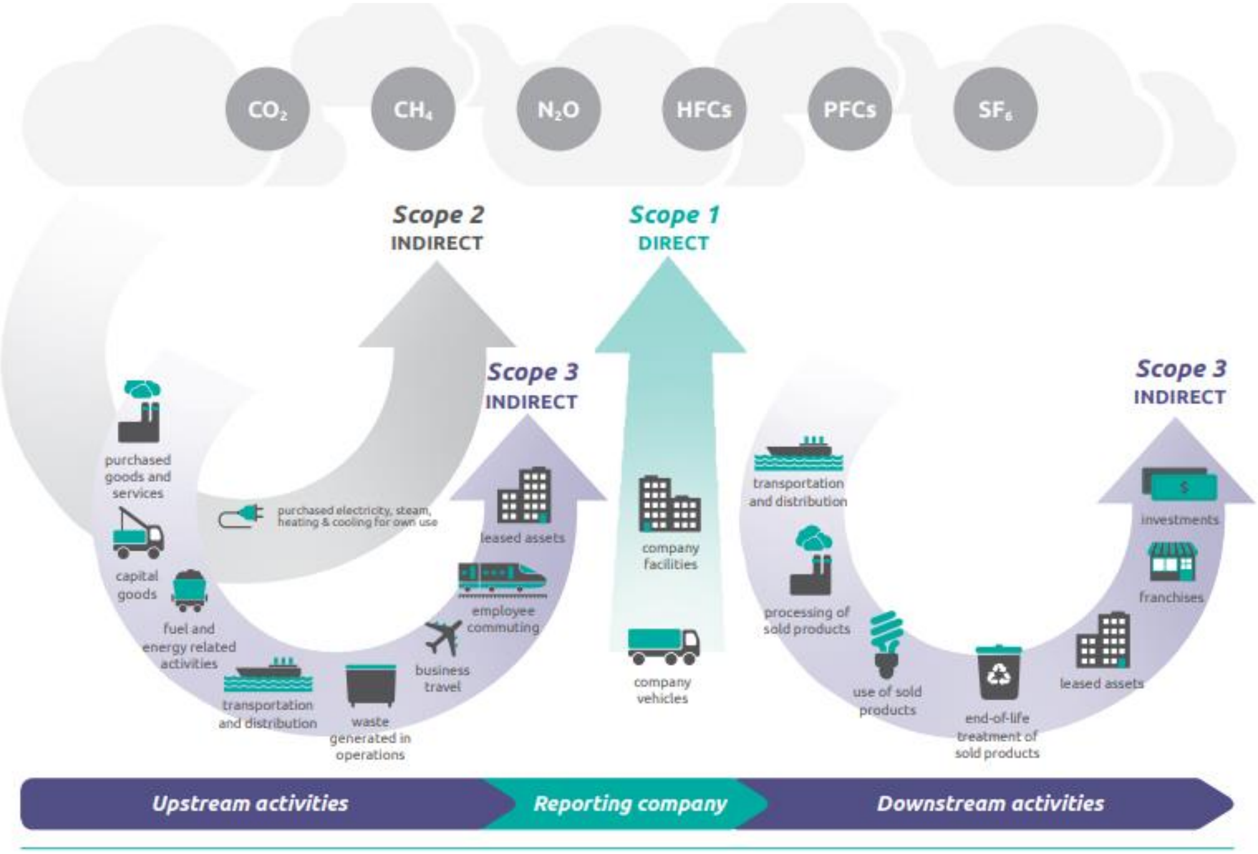

Figure 1: Value chain representation of company emissions

It is acknowledged that the use of sales data in estimating Scope 3 category 11 emissions is open to error because emissions result from product consumption and not product sale. The delay between product sale and consumption varies but is not typically significant; therefore, this methodology assumes that all sold oil and gas products are consumed, or 'used', in the same reporting year. For a product used for non-energy purposes, total emissions may not occur initially but over the course of a prolonged lifetime. Category 11 includes emissions occurring in the present and in the future [3, p.33].

3. Industry and company structure

This guidance applies to companies involved in the extraction and production of oil and gas (upstream), companies involved in the transport, handling, and storage of oil and gas and derived products (midstream), companies involved in the refining/processing of oil and gas derived products (downstream), and integrated companies involved in multiple areas of the oil and gas value chain. All industry products recognized as conventional or unconventional are included.

Guidance for reporting Scope 3 category 11 emissions for companies with coal operations is provided in a separate document.

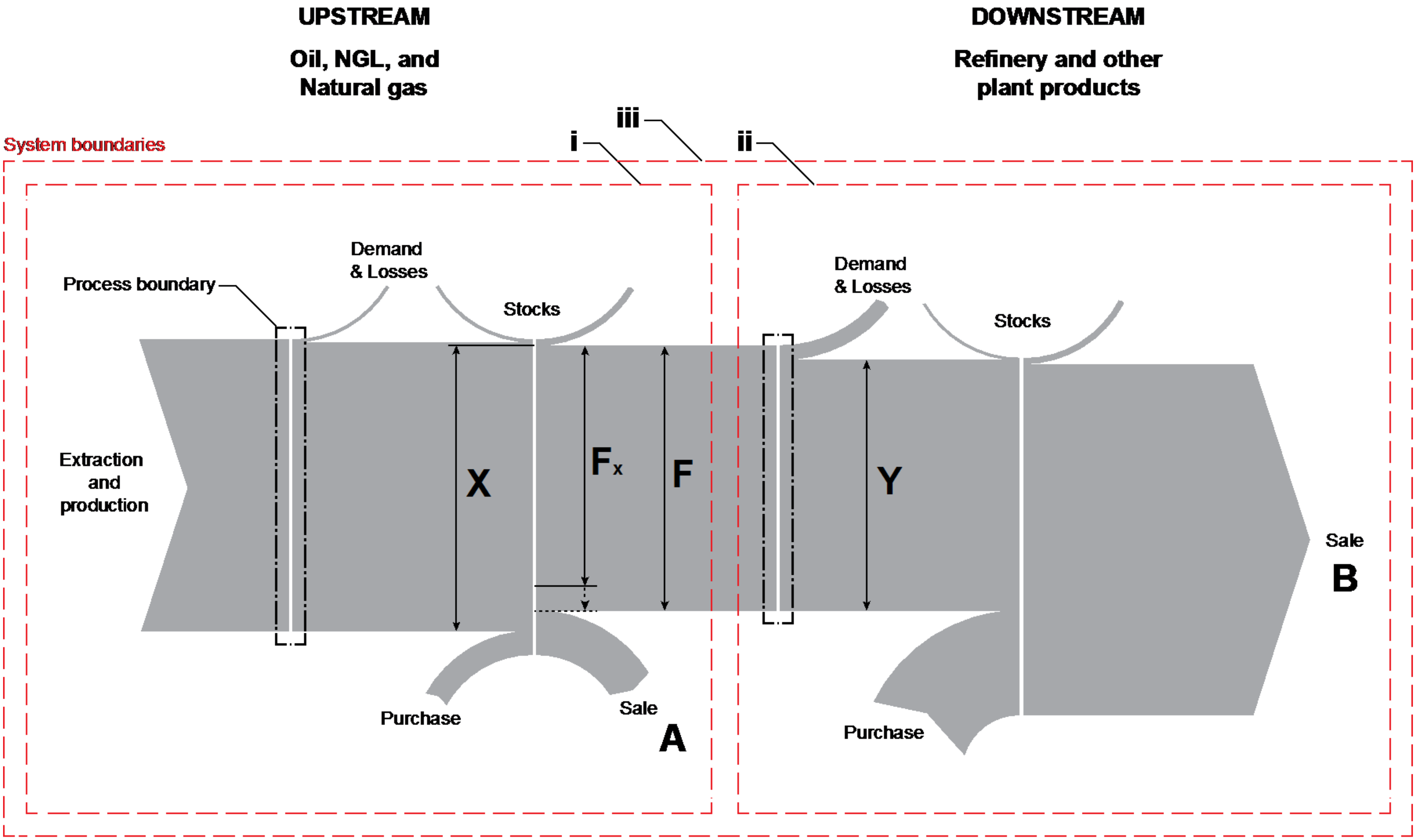

Figure 2: Sankey diagram illustrating aggregate material flows through oil and gas companies

Aggregate material flows for these company types are depicted in Figure 2. Companies purely involved in the transport, handling, and storage of oil and gas and derived products should base the material flows in their operations on the throughput of products and consult section 5.3 for further details. Upstream companies are encompassed by system boundary (i), downstream companies by system boundary (ii), and integrated companies by system boundary (iii). Each step along the process chain is marked by a narrow gap in the flow. At each step a product may be consumed as fuel, used as feedstock, lost[3], added to or taken from stocks, or traded with suppliers and consumers. The diagram excludes flows if they are external to the organizational boundary, as defined by the company, e.g. partner-company or royalty allocations. Upstream and downstream sale[4] of hydrocarbons is labelled A and B respectively. Upstream and downstream production of hydrocarbons is labelled X and Y respectively. Use of own upstream production X as feedstock is labelled F_X, which should be deducted from the sum of X and Y in the calculation of integrated company net production. Total feedstock to downstream processes is labelled F. Equations (1-3) express the definition of net production (with reference to Figure 2) for each company type. A_X is upstream sale deriving from own upstream production X, and may be summed with Y as another approach to calculating integrated company net production.

$$P_i = X \tag{1}$$

$$P_{ii} = Y \tag{2}$$

$$P_{iii} = Y + X - F_X = Y + A_X \tag{3}$$

Equations (4-6) define the limits of net production (with reference to Figure 2) for integrated companies. In Figure 2 a dashed line indicates the maximum value of F_X, where this maximum is equal to F when X > F (as in Figure 2) or is equal to X when X < F. In the former case, it is assumed that no upstream purchases are used as feedstock to the company's own downstream operations. In the latter case[5], it is assumed that upstream purchases are only used as feedstock for overcoming upstream production deficits. Conversely, the minimum value of F_X occurs when only upstream purchases are used as feedstock to downstream operations, in which case X contributes exclusively to A and $F_X = 0$. In this case, if the company's upstream sales derive exclusively from its own production, then X = A, and thus A may be substituted for X in Equation (6).

$$P_{iii\,(min)} = Y + X - F \qquad [\text{when } X > F] \tag{4}$$

or,

$$P_{iii\,(min)} = Y \qquad [\text{when } X < F] \tag{5}$$

$$P_{iii\,(max)} = Y + X \tag{6}$$

Equations (7-9) express the definition of sales (with reference to Figure 2) for each company type. Sales, as defined here, can only represent material flows leaving a company's organizational boundary, in which case integrated company sale is the summation of upstream and downstream sale.

$$S_i = A + F \tag{7}$$

$$S_{ii} = B \tag{8}$$

$$S_{iii} = A + B \tag{9}$$

[3] Losses include controlled, e.g. venting and flaring, and accidental losses.
[4] Sales must cross the organizational boundary; this excludes sales between company subsidiaries.
[5] To view aggregate material flow for both conditions of X refer to section A4 of the Appendix.

4. Relevance

GHG Protocol guidance on Scope 3 reporting [2-3] defines a set of criteria for identifying relevant Scope 3 categories. As stated at the end of section 2.2, this guidance applies to the estimation of category 11 emissions only; this focus is applied because of the size of these emissions associated with the oil and gas industry. As shown in Table 1, this represents one in a set of relevancy criteria.

Criteria	Description of activities
Size	They contribute significantly to the company's total anticipated Scope 3 Emissions
Influence	There are potential emissions reductions that could be undertaken or influenced by the company
Risk	They contribute to the company's risk exposure (e.g., climate change related risks such as financial, regulatory, supply chain, product and technology, compliance/litigation, and reputational risks)
Stakeholders	They are deemed critical by key stakeholders (e.g., customers, suppliers, investors or civil society)
Outsourcing	They are outsourced activities previously performed in-house or activities outsourced by the reporting company that are typically performed in-house by other companies in the reporting company's sector
Sector guidance	They have been identified as significant by sector-specific guidance
Spending or revenue analysis	They are areas that require a high level of spending or generate a high level of revenue (and are sometimes correlated with high GHG emissions)
Other	They meet any additional criteria developed by the company or industry sector

Table 1: Criteria for identifying relevant Scope 3 activities [adapted from ref. 3, p.61]

It should be acknowledged that double counting between companies is an inherent characteristic of Scope 3 emissions. This is because Scope 3 emissions occur outside of the company's organizational boundary and, thus, inside the boundary (Scope 1) of other emitting entities or companies. Double counting may also occur between categories within Scope 3; for example, if two companies simultaneously account for third-party transportation of goods between them [3, p.108].

Viewing category 11 at the industry level, double counting would need to be avoided so as to aggregate to the industry total. However, industry level emissions accounting is not the purpose of Scope 3 disclosure and would be more suitably estimated via the use of statistical datasets such as those compiled by the International Energy Agency (IEA) and the US Energy Information Administration (EIA).

Viewing category 11 at the company level, there should be no deductions from a company's sale of products on the basis of double counting with another company. For example, a company should not deduct the emissions of an upstream product if the product is used as feedstock for a different company's downstream production. Within a single company's inventory, however, double counting should be avoided. For example, a company should deduct the Scope 3 emissions related to an upstream product if the product is used as feedstock for its own downstream production. Often, reported company sales volumes include transactions between different subsidiaries of that company, therefore the material flow does not cross the organizational boundary. In this case the company should deduct internal sales from this ‘gross’ sales figure in order to avoid double counting.

For E&P companies, refiners/processors, and integrated companies, comparing accountability for product emissions is complex. This is because there is significant trading of products between upstream and downstream production processes, intra- and inter-companies. An alternative approach to comparing companies within this sample is to redefine category 11 activity data as net production (as opposed to sales). This approach is relevant if accountability for emissions is defined by a company’s direct involvement in the extraction of natural stores of carbon and the conversion of carbon into usable products.

As described in the previous section, a company’s net production (P) is defined as the total production after deducting for losses, stock changes, and self-consumption. Self-consumption is defined as the consumption by a company of its own production, i.e. as fuel or feedstock. For an integrated company, total production includes production of both upstream and downstream products.

As expressed in Equation (3), calculating net production of upstream and downstream products requires data on the company’s consumption of its own upstream production as feedstock (F_X) or sale of its own upstream production (A_X). If these data are difficult to obtain, the analyst may wish to apply a minimum or maximum boundary, as in Equations (4-6). If the structure of an integrated company is weighted to upstream production, then the analyst may wish to apply Equation (4). In this case, $P_{iii}(min) \approx X$ so the analyst may decide to simplify the approach and count only upstream production. If the structure is weighted to downstream production, then the analyst may wish to apply Equation (5), $P_{iii}(min) = Y$. In either case, the analyst should acknowledge that these simplifications equate to a minimum limit of Scope 3 category 11 emissions and could present a misleading picture. For example, an E&P company and an upstream oriented integrated company would be measured by the same activity regardless of additional downstream activity arising from the latter. And over time, if the integrated company’s upstream production decreases while downstream (net of F_X) increases at a faster rate, then successive estimations would show Scope 3 emissions to be falling when they are in fact rising.

Accountability can also be complex for companies that handle O&G products without actually owning them (e.g. pipelines and storage, gas distribution networks). While O&G products are not directly sold by these companies, the emissions from their end use still generates Scope 3 emissions, that arise as “a consequence of an organization’s operations and activities, but that arises from GHG sources that are not owned or controlled by the [reporting] organization.” [6]. Much like the O&G producers, these emissions can constitute significant and substantial emissions [7]. Reporting scope 3 category 11 emissions for handled O&G products places these companies on the same footing as the rest of the O&G value chain and resolves a fundamental unfairness for the rest of the industry.

5. Methodology

The estimation methodology builds on the tier approach established under the 2006 IPCC Guidelines for National Greenhouse Gas Inventories [8]. The fundamental form of estimation combines data on the extent to which a human activity takes place (activity data) with coefficients that quantify the emissions, or removals, per unit of activity (emission factors). This relationship is expressed in Equation (10).

$$\text{Emissions} = \text{Activity data} \bullet \text{Emission factor} \tag{10}$$

The level of methodological complexity is represented by three tiers: tier 1 (basic), tier 2 (intermediate), and tier 3 (advanced). Tier 1 is generally designed for the application of readily available, or aggregate, company activity data with default emission factors, which are available, for example, from IPCC default parameter tables [9, p.2. 16]. Tier 2 and tier 3 are designed for the use of more granular activity data and emission factors and for a wider inclusion of process parameters. Tier 2 and tier 3 are referred to as *higher tier* methods.

This guidance distinguishes between tier 1 and higher tier estimation complexity. The company analyst should choose estimation complexity based on the time and resources available. If attempting higher tier estimation, the analyst should refer to sections on both tier 1 and higher tier.

Choice of activity data is dependent on the definition of what activities are deemed relevant to the company. As discussed in section 4, relevance is dependent on a set of key criteria and other considerations specific to the industry. This guidance describes two distinct choices for activity data which reflect two alternative views on relevancy. The first choice incorporates sales data while the second choice incorporates production data.

5.1 Sales Method

A company may sell significantly different quantities of hydrocarbon product than it produces. In such a case the analyst should consider GHG Protocol Guidance on activity relevancy (see section 4). If the sale of hydrocarbon products purchased from other companies is deemed relevant, then the analyst should apply the sales approach. Only sales that cross the organizational boundary should be counted.

5.1.1 Tier 1

The tier 1 emissions calculation is expressed in Equations (11-12).

$$E_{S3.11} = \sum_{p=1} S_p \cdot EF_p^{c} \tag{11}$$

or,

$$E_{S3.11} = \sum_{p=1} S_p \cdot HV_p \cdot EF_p^{ce} \tag{12}$$

Where[6]*:*

$E_{S3.11}$	*= Scope 3 category 11 GHG emissions, units: metric tons (t) of CO_2e*
p	*= hydrocarbon product*
S	*= quantity sold, units: t, mmbbl, mbpd, boe, boed, bcf, mmcm, etc.*
HV	*= heating value, units: GJ/kg, TJ/Gg, toe/m^3, boe/gal., Btu/cf, etc.*
EF^c	*= full combustion emission factor, units: tCO_2e/t, tCO_2e/mcm, $tCO_2e/mmBtu$, etc.*
EF^{ce}	*= full combustion energy emission factor, units: tCO_2e/TJ, tCO_2e/boe, etc.*

Note:

a: *Product totals shall be disaggregated, e.g. upstream into crude oil, natural gas, and natural gas liquids; downstream into gasolines, kerosene, fuel oils, and other.*

Upstream products include oil, natural gas, and natural gas liquids (NGLs) and should be separated as such. Oil is more variable in its carbon content than natural gas or NGL so the analyst should apply his or her own professional judgement as to its level of disaggregation, e.g. crude oil, bitumen, synthetic oil, shale oil, and oil sands, or to apply an average EF that is more representative of the oil portfolio than the global average.

Downstream products should also be disaggregated. Product groupings already disclosed in annual filings may be chosen, e.g. gasolines, kerosene, fuel oils, and other. It is expected that the company analyst applies knowledge of those products labelled as other.

If the analyst is aware of a product that is unlikely to release all of its carbon within its lifetime, then the analyst may wish to adjust for this. For example, if asphalt is sold for road surfacing and other non-energy use (NEU) applications, then the analyst may wish to exclude this product from the estimation. If data on product application is unavailable, then the analyst should apply his or her own professional judgement.

Activity can be measured in units of mass, volume, or energy. If the analyst has activity data in physical units (mass or volume) and uses energy emission factors (EF^{ce}), then Equation (12) should be adopted. If the analyst has volumetric activity data and mass emission factors, or *vice versa*, then the analyst should obtain and apply product density data before adopting Equation (11). The analyst should aim to match physical data units to minimize the number of steps in the calculation.

Should the analyst only have ready access to production data, then this may be used as a proxy for sales data based on the following conditions: the company is not integrated; production excludes that which is consumed by the company; the analyst is aware of no other reason why production would be significantly different from sales, e.g. product storage.

It is common for companies to analyze energy by higher heating value (HHV), as opposed to lower heating value (LHV)[7]. LHV is lower than HHV by the latent energy of vaporization of the water product of combustion. For fossil fuel solids and liquids, the LHV/HHV ratio is typically 0.95, and for gases it is typically 0.9. The analyst should be consistent with the use of either HHV or LHV. For example, if EF^{ce} represents an emission per LHV, then the analyst should use activity data in LHV or convert activity data to LHV from HHV or physical unit.

The analyst should not use carbon dioxide (CO_2)[8] EFs as a proxy for greenhouse gas EFs. When used together, GHGs are measured in carbon dioxide equivalent (CO_2e). Relevant GHGs include

[6] For unit descriptions please refer to section A6 of the Appendix.
[7] LHV may also be referred to as the net calorific value (NCV), and HHV the gross calorific value (GCV).
[8] If necessary, carbon content (C) should be converted to CO2 using the molecular ratio (CO2 = 44/12 C).

CO_2, methane (CH_4), and nitrous oxide (N_2O). To convert from non-CO_2 to CO_2e, the analyst should apply global warming potential (GWP) factors. GWP relates the radiative forcing of a greenhouse gas over a certain period of time to that of CO_2. Where necessary, the analyst should apply the 100-year GWPs published in the IPCC Fifth Assessment report [1, Table 8.7]; for CH_4 and N_2O these are 34 and 298 respectively.

5.1.2 Higher Tier

The higher tier emissions calculation is expressed in Equations (13-15).

$$E_{S3.11} = \sum_{p=1} S_p \cdot EF_p^c \cdot EO_p \qquad (13)$$

or,

$$E_{S3.11} = \sum_{p=1} S_p \cdot C_p \cdot {}^{44}/_{12} \cdot GR_p \cdot EO_p \qquad (14)$$

where,

$$EO_p = OF_p \cdot (1 - NEU_p) + NEU_p \cdot (1 - SF_p) \qquad (15)$$

Where[9]*:*

$E_{S3.11}$	*= Scope 3 category 11 GHG emissions, units: metric tons (t) of CO_2e*
p	*= hydrocarbon product*
S	*= quantity sold, units: t, mmbbl, mbpd, boe, boed, bcf, mmcm, etc.*
C	*= Carbon content*
GR	*= GHG gas ratio (CO_2e/CO_2)*
EF^c	*= full combustion emission factor, units: tCO_2e/t, tCO_2e/mcm, $tCO_2e/mmBtu$, etc.*
EO	*= effective oxidation rate*
OF	*= oxidation factor*
NEU	*= non-energy use fraction*
SF	*= storage factor*

Note:

a:	*Product totals shall be disaggregated, e.g. upstream into oil (see note b), natural gas, and natural gas liquids; downstream into motor gasoline, diesel, naphtha, fuel oil, residual fuel oil, kerosene, and liquefied petroleum gas.*
b:	*Oil shall be disaggregated or applied with a representative average emission factor.*
c:	*Physical unit (mass or volume) of activity data and emission factors should match and the use of heating values should be avoided.*
d:	*Effective oxidation rate should be determined for each product or product category.*

Upstream products include oil, natural gas, and natural gas liquids (NGLs) and should be separated as such. Oil (heavy/medium/light crude oil, bitumen, synthetic oil, shale oil, oil sands, etc.) should be further disaggregated to distinguish between products of different carbon content. The analyst may not use a global average, or default, emission factor for oil but must use company data, e.g. oil assays.

Downstream products should also be disaggregated. The analyst should aim to disaggregate activity data for downstream products in alignment with recognized product categories of the industry. These are exemplified in Table A-1 of the Appendix.

The analyst should also take account of product oxidation. Imperfect combustion is accounted for

[9] For unit descriptions refer to the Nomenclature

by the product's oxidation factor (OF), which is typically between 0.99 and 1. The OF is applied to the non-NEU fraction of product p. Within the NEU fraction of product p, a portion of carbon is stored. This portion is accounted for by the product's storage factor (SF). Taking these factors into account, the analyst may estimate a product's effective oxidation rate (EO). The EO is defined here as the ultimate proportion of a product that is emitted over its lifetime. For an analysis of these factors, refer to section A2 of the Appendix.

The analyst shall not use production data as a proxy for sales data under any circumstances.

As with tier 1, the analyst should account for non-CO_2 emissions and, where necessary, apply GWPs of 34 and 298 for CH_4 and N_2O, respectively. Equation (14) introduces the gas ratio (GR), which is the ratio of product greenhouse gas to carbon dioxide (CO_2e / CO_2). For ease of calculation, the gas ratio is used alongside data pertaining to carbon content only. The gas ratio may also be used were information on CH_4 or N_2O data is difficult to obtain. Estimated GR values can be found in Table A-1 of the Appendix.

When using EF data from literature, the analyst should match physical data units (mass or volume) between activity data and emission factors. The analyst should avoid using heating values and energy emission factors but apply raw physical data with physical emission factors.

For oil emission factors the analyst should use company data. Carbon content may be obtained directly from chemical analyses or estimated from product API gravity and sulfur content. Chapter 2 of the IPCC publication "Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories" [10] contains a method for estimating oil carbon content from API gravity and sulfur content. The method is expressed in Equations (16-17), where C is carbon content (%), SC is sulfur content (%), SG is specific gravity, API is the API gravity[10] at 60 degrees Fahrenheit.

$$C=76.99+10.19 \cdot SG - 0.76 \cdot SC \tag{16}$$

where,

$$SG= \frac{141.5}{(API+131.5)} \tag{17}$$

If necessary, the analyst may use API gravity to convert oil activity data from volume to mass. The relationship between oil density and API is expressed in Equation (18), where ρ is density (t/bbl).

$$\rho = \frac{141.5 \cdot 0.159}{API + 131.5} \tag{18}$$

5.2 Production method[11]

A company may produce significantly different quantities of hydrocarbon product than it sells. In such a case the analyst should consider GHG Protocol Guidance on activity relevancy (see section 4). If the sale of hydrocarbon products purchased from other companies is deemed irrelevant, then the analyst may wish to apply the production approach. There may exist other practical reasons as to why the production method is selected over sales, e.g. lack of traceability in

[10] In 1921 the API scale replaced the Baumé scale, which should be avoided here.
[11] This section is structured identically to section 5.1.

volumetric sales intra- and inter-organizational boundaries.

5.2.1 Tier 1

The tier 1 emissions calculation is expressed in Equations (19-20).

$$E_{S3.11} = \sum_{p=1} P_p \cdot EF_p^c \tag{19}$$

or,

$$E_{S3.11} = \sum_{p=1} P_p \cdot HV_p \cdot EF_p^{ce} \tag{20}$$

Where[12]*:*

$E_{S3.11}$	*= Scope 3 category 11 GHG emissions, units: metric tons (t) of CO_2e*
p	*= hydrocarbon product*
P	*= net production, units: t, mmbbl, mbpd, boe, boed, bcf, mmcm, etc.*
HV	*= heating value, units: GJ/kg, TJ/Gg, toe/m^3, boe/gal., Btu/cf, etc.*
EF^c	*= full combustion emission factor, units: tCO_2e/t, tCO_2e/mcm, tCO_2e/mmBtu, etc.*
EF^{ce}	*= full combustion energy emission factor, units: tCO_2e/TJ, tCO_2e/boe, etc.*

Note:

a: *Product totals shall be disaggregated, e.g. upstream into oil, natural gas, and natural gas liquids; downstream into gasolines, kerosene, fuel oils, and other.*

Upstream products include oil, natural gas, and natural gas liquids (NGLs) and should be separated as such. Oil is more variable in its carbon content than natural gas or NGL so the analyst should apply his or her own professional judgement as to its level of disaggregation, e.g. crude oil, bitumen, synthetic oil, shale oil, and oil sands, or to apply an average EF that is more representative of the oil portfolio than the global average.

Downstream products should also be disaggregated. Product groupings already disclosed in annual filings may be chosen, e.g. gasolines, kerosene, fuel oils, and other. It is expected that the company analyst applies knowledge of those products labelled as other.

If the analyst is aware of a product that is unlikely to release all of its carbon within its lifetime, then the analyst may wish to adjust for this. For example, if asphalt is produced for road surfacing and other non-energy use (NEU) applications, then the analyst may wish to exclude this product from the estimation. If data on product application is unavailable, then the analyst should apply his or her own professional judgement.

Activity can be measured in units of mass, volume, or energy. If the analyst has activity data in physical units (mass or volume) and uses energy emission factors (EFce), then Equation (20) should be adopted. If the analyst has volumetric activity data and mass emission factors, or *vice versa*, thenthe analyst should obtain and apply product density data before adopting Equation (19). The analyst should aim to match physical data units so as to minimize the number of steps in the calculation.

It is common for companies to analyze energy by higher heating value (HHV), as opposed to lower heating value (LHV)[13]. LHV is lower than HHV by the latent energy of vaporization of the

[12] For unit descriptions please refer to section A6 of the Appendix.

[13] LHV may also be referred to as the net calorific value (NCV), and HHV the gross calorific value (GCV).

water product of combustion. For fossil fuel solids and liquids, the LHV/HHV ratio is typically 0.95, and for gases it is typically 0.9. The analyst should be consistent with the use of either HHV or LHV. For example, if EF^{ce} represents an emission per LHV, then the analyst should use activity data in LHV or convert activity data to LHV from HHV or physical units.

The analyst should not use carbon dioxide (CO_2)[14] EFs as a proxy for greenhouse gas EFs. When used together, GHGs are measured in carbon dioxide equivalent (CO_2e). Relevant GHGs include CO_2, methane (CH_4), and nitrous oxide (N_2O). To convert from non-CO_2 to CO_2e, the analyst should apply global warming potential (GWP) factors. GWP relates the radiative forcing of a greenhouse gas over a certain period of time to that of CO_2. Where necessary, the analyst should apply the 100-year GWPs published in the IPCC Fifth Assessment report [1, Table 8.7]; for CH_4 and N_2O these are 34 and 298 respectively.

[14] If necessary, carbon content (C) should be converted to CO_2 using the molecular ratio (CO_2 = 44/12 C).

5.2.2 Higher Tier

The higher tier emissions calculation is expressed in Equations (21-23).

$$E_{S3.11} = \sum_{p=1} P_p \cdot EF_p^c \cdot EO_p \quad (21)$$

or,

$$E_{S3.11} = \sum_{p=1} P_p \cdot C_p \cdot {}^{44}/_{12} \cdot GR_p \cdot EO_p \quad (22)$$

where,

$$EO_p = OF_p \cdot (1 - NEU_p) + NEU_p \cdot (1 - SF_p) \quad (23)$$

Where[15]*:*

$E_{S3.11}$	*= Scope 3 category 11 GHG emissions, units: metric tons (t) of CO_2e*
p	*= hydrocarbon product*
P	*= net production, units: t, mmbbl, mbpd, boe, boed, bcf, mmcm, etc.*
C	*= Carbon content*
GR	*= GHG gas ratio (CO_2e/CO_2)*
EF^c	*= full combustion emission factor, units: tCO_2e/t, tCO_2e/mcm, $tCO_2e/mmBtu$, etc.*
EO	*= effective oxidation rate*
OF	*= oxidation factor*
NEU	*= non-energy use fraction*
SF	*= storage factor*

Note:

- a: *Product totals shall be disaggregated, e.g. upstream into oil (see note b), natural gas, and natural gas liquids; downstream into motor gasoline, diesel, naphtha, fuel oil, residual fuel oil, kerosene, and liquefied petroleum gas.*
- b: *Oil shall be disaggregated or applied with a representative average emission factor.*
- c: *Physical unit (mass or volume) of activity data and emission factors should match and the use of heating values should be avoided.*
- d: *Effective oxidation rate should be determined for each product or product category.*

Upstream products include oil, natural gas, and natural gas liquids (NGLs) and should be separated as such. Oil (heavy/medium/light crude oil, bitumen, synthetic oil, shale oil, oil sands, etc.) should be further disaggregated to distinguish between products of different carbon content. The analyst may not use a global average, or default, emission factor for oil but must use company data, e.g. oil assays.

Downstream products should also be disaggregated. The analyst should aim to disaggregate activity data for downstream products in alignment with recognized product categories of the industry. These are exemplified in Table A-1 and of the Appendix.

The analyst should also take account of product oxidation. Imperfect combustion is accounted for by the product's oxidation factor (OF), which is typically between 0.99 and 1. The OF is applied to the non-NEU fraction of product p. Within the NEU fraction of product p, a portion of carbon is stored. This portion is accounted for by the product's storage factor (SF). Taking these factors into account, the analyst may estimate a product's effective oxidation rate (EO). The EO is defined here as the ultimate proportion of a product that is emitted over its lifetime. For an analysis of these factors, refer to section A2 of the Appendix.

[15] For unit descriptions please refer to section A6 of the Appendix.

As with tier 1, the analyst should account for non-CO_2 emission and, where necessary, apply GWPs of 34 and 298 for CH_4 and N_2O, respectively. Equation (22) introduces the gas ratio (GR), which is the ratio of product greenhouse gas to carbon dioxide (CO_2e / CO_2). For ease of calculation, the gas ratio is used alongside data pertaining to carbon content only. The gas ratio may also be used were information on CH_4 or N_2O data is difficult to obtain. Estimated GR values can be found in Table A-1 of the Appendix.

When using EF data from literature, the analyst should match physical data units (mass or volume) between activity data and emission factors. The analyst should avoid using heating values and energy emission factors but apply raw physical data with physical emission factors.

For oil emission factors the analyst should use company data. Carbon content may be obtained directly from chemical analyses or estimated from product API gravity and sulfur content. Chapter 2 of the IPCC publication "Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories" [10] contains a method for estimating oil carbon content from API gravity and sulfur content. The method is expressed in Equations (18-19), where C is carbon content (%), SC is sulfur content (%), SG is specific gravity, API is the API gravity[16] at 60 degrees Fahrenheit.

$$C=76.99+10.19 \cdot SG - 0.76 \cdot SC \qquad (24)$$

where,

$$SG= \frac{141.5}{(API+131.5)} \qquad (25)$$

If necessary, the analyst may use API gravity to convert oil activity data from volume to mass. The relationship between oil density and API is expressed in Equation (26), where ρ is density (t/bbl).

$$\rho = \frac{141.5 \cdot 0.159}{API + 131.5} \qquad (26)$$

[16] In 1921 the API scale replaced the Baumé scale, which should be avoided here.

5.3 Throughput Method

Companies which handle oil and gas products but do not own the products themselves should calculate their Scope 3 category 11 emissions based on the throughput of these products through their operations. This represents the best way to capture the amount of product these companies have a role in processing, and thus the amount of product that they should report Scope 3 emissions for.

As discussed in section 4, integrated companies should avoid double counting within their inventory. For example, any Scope 3 emissions for a transported product should be deducted if that product is used as a feedstock for downstream production. The Net Value Chain approach may be a useful method to calculate volumes for integrated companies. See the SBTi guidance for further details (p.12-15).

The emissions calculation is expressed in Equations (27-28).

$$E_{S3.11} = \sum_{p=1} T_p * EF_p^c \tag{27}$$

or,

$$E_{S3.11} = \sum_{p=1} T_p \cdot \mathrm{HV_p} \cdot \mathrm{EF_p^{ce}} \tag{28}$$

Where[17]:

$E_{S3.11}$	*= Scope 3 category 11 GHG emissions, units: metric tons (t) of CO_2e*
p	*= hydrocarbon product*
T	*= net throughput, units: t, mmbbl, mbpd, boe, boed, bcf, mmcm, etc.*
HV	*= heating value, units: GJ/kg, TJ/Gg, toe/m^3, boe/gal., Btu/cf, etc.*
EF^c	*= full combustion emission factor, units: tCO_2e/t, tCO_2e/mcm, $tCO_2e/mmBtu$, etc.*
EF^{ce}	*= full combustion energy emission factor, units: tCO_2e/TJ, tCO_2e/boe, etc.*

Note:

a: *Product totals shall be disaggregated, e.g. upstream into crude oil, natural gas, and natural gas liquids; downstream into gasolines, kerosene, fuel oils, and other.*

Upstream products include oil, natural gas, and natural gas liquids (NGLs) and should be separated as such. Oil is more variable in its carbon content than natural gas or NGL so the analyst should apply his or her own professional judgement as to its level of disaggregation, e.g. crude oil, bitumen, synthetic oil, shale oil, and oil sands, or to apply an average EF that is more representative of the oil portfolio than the global average.

Downstream products should also be disaggregated. Product groupings already disclosed in annual filings may be chosen, e.g. gasolines, kerosene, fuel oils, and other. It is expected that the company analyst applies knowledge of those products labelled as other.

[17] For unit descriptions please refer to section A6 of the Appendix.

If the analyst is aware of a product that is unlikely to release all of its carbon within its lifetime, then the analyst may wish to adjust for this. For example, if asphalt for road surfacing and other non-energy use (NEU) applications is included, then the analyst may wish to exclude this product from the estimation. If data on product application is unavailable, then the analyst should apply his or her own professional judgement.

Activity can be measured in units of mass, volume, or energy. If the analyst has activity data in physical units (mass or volume) and uses energy emission factors (EF^{ce}), then Equation (28) should be adopted. If the analyst has volumetric activity data and mass emission factors, or vice versa, then the analyst should obtain and apply product density data before adopting Equation (27). The analyst should aim to match physical data units to minimize the number of steps in the calculation.

It is common for companies to analyze energy by higher heating value (HHV), as opposed to lower heating value (LHV). LHV is lower than HHV by the latent energy of vaporization of the water product of combustion. For fossil fuel solids and liquids, the LHV/HHV ratio is typically 0.95, and for gases it is typically 0.9. The analyst should be consistent with the use of either HHV or LHV. For example, if EF^{ce} represents an emission per LHV, then the analyst should use activity data in LHV or convert activity data to LHV from HHV or physical unit.

The analyst should not use carbon dioxide (CO^2) EFs as a proxy for greenhouse gas EFs. When used together, GHGs are measured in carbon dioxide equivalent (CO^2e). Relevant GHGs include CO2, methane (CH^4), and nitrous oxide (N^2O). To convert from non-CO^2 to CO^2e, the analyst should apply global warming potential (GWP) factors. GWP relates the radiative forcing of a greenhouse gas over a certain period of time to that of CO^2. Where necessary, the analyst should apply the 100-year GWPs published in the IPCC Fifth Assessment report [1, Table 8.7]; for CH^4 and N^2O these are 34 and 298 respectively.

6. Disclosure

For general guidance on the disclosure of Scope 3 emissions to CDP, the reader is referred to module C6 of the CDP climate change reporting guidance. The reporting company is required to disclose an estimation of Scope 3 emissions in question C6.5 along with information on the methodology with which the figure was estimated. Table 2 details what an effective disclosure of category 11 estimation 'Emissions calculation methodology', table question column 4, should include.

Information	Description	Disclosure example
Methodological approach	Direct reference to estimation method described in this document: - 'Sales method' - 'Production method' - 'Throughput method' The reporter may also wish to state whether the estimation was tier 1 or higher tier. If the method used is not one of the above methods, then the reporter should state this and describe the adopted methodology or differences from the above.	Using the Production method; Tier 1.
Coverage	Confirm whether or not all activity inside the organizational boundary is included. Confirm if activity data is net of royalties. No activity inside the organizational boundary should be excluded. [Note: the reporting company should already have disclosed the boundary definition, e.g. equity share, in question C0.5, and the estimation should apply this boundary]	Not all activity inside the organizational boundary is included. Only upstream production is included. The organizational boundary is equity share.
Activity data	State activity data type: 'net production' or 'sales'. The reporter should state if production or sales differs in any way to the definitions outlined in this document, or if proxy data is used (with justification). The reporter may also wish to refer directly Figure 2 by referencing the material flows included.	Activity data is net production; P = X.
Product information	State all products included and relevant calculation information so that the estimation can be reproduced. This includes the product name and amount produced/sold. The reporter may also wish to include calculation parameters: EF and, if used, LHV/HHV and oxidation rate information. If the calculation parameters are taken directly from literature, then the literature source may be referenced instead. If company emission factors or activity data are deemed sensitive information, then an approximate or aggregated form of activity disclosure enabling a rough reproduction of the estimation is sufficient.	Products include: Natural gas (505 million cubic feet per day; 53 ktCO2e per bcf); Fuel oil…
Sources	Reference the source(s) of activity data, emission factors, and any other sources used, citing the references where they are used or listing them at the end stating what they were used for.	Emission factors from US EPA 2014 – Emission Factors for Greenhouse gas inventories.
Other	Any other pertinent information.	

Table 2: Recommended items to include in 'Emissions calculation methodology' disclosure for question C6.5

7. References

[1] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp.

[2] WRI/WBCSD, 'The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. Revised Edition', World Business Council for Sustainable Development and World Resources Institute, Geneva and Washington DC, 2004.

[3] WRI/WBCSD, 'Greenhouse Gas Protocol: Corporate Value Chain (Scope 3) Accounting and Reporting Standard', World Business Council for Sustainable Development and World Resources Institute, Geneva and Washington DC, 2011.

[4] WRI/WBCSD, 'Greenhouse Gas Protocol: Technical Guidance for Calculating Scope 3 Emissions', World Business Council for Sustainable Development and World Resources Institute, Geneva and Washington DC, 2013.

[5] IPIECA, 'Petroleum industry guidelines for reporting greenhouse gas emissions. Second Edition', IPIECA, London, 2011.

[6] ACT, 'ACT O&G methodology', ACT, 2021

[7] Flora, A., Wynn, G., 'Hiding in Plain Sight—European Gas Pipeline Companies' Greenhouse Gas Emissions', IEEFA,

[8] IPCC, '2006 IPCC Guidelines for National Greenhouse Gas Inventories. Volume 1: General Guidance and Reporting', IGES, Japan, 2006.

[9] IPCC, '2006 IPCC Guidelines for National Greenhouse Gas Inventories. Volume 2: Energy', IGES, Japan, 2006.

[10] IPCC, 'Chapter 2 Energy', 'Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories', IGES, Japan, 2001.

[11] API, 'Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry', American Petroleum Institute, Washington DC, 2009.

[12] AEA, 'Annex 1 - Converting from fuel use to carbon dioxide equivalent emissions', *2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company*. 2012.

[13] AEA, 'Annex 11 - Fuel Properties', *2012 Guidelines to Defra / DECC's GHG Conversion Factors for Company Reporting*. 2012.

[14] BP, 'NGL', *BP*, 2014. [Online]. Available: http://www.bp.com/en_na/gas/north-america/learn- more/ngl.html. [Accessed: 20-Oct-2015].

[15] Eurostat, "Supply, transformation and consumption of gas - annual data," in (nrg_103a), 2015.

[16] Eurostat, "Supply, transformation and consumption of oil - annual data," in (nrg_102a), 2015.

[17] IEA, '2015 Key World Energy Statistics,' OECD/IEA, Paris, 2015.

[18] UNFCCC, 'Table 1.A(b) Sectoral Background Data for Energy: CO2 from Fuel Combustion Activities - Reference Approach', *National Inventory Submissions 2014: Common Reporting Format*. 2014.

[19] UNFCCC, 'Table 1.A(d) Sectoral Background Data for Energy: Feedstocks and Non-Energy Use of Fuels', *National Inventory Submissions 2014: Common Reporting Format*. 2014.

Appendix

A1 Tier 1 defaults

Fuel	API (60°F)	ρ, kg/m^3	HHV,GJ $/m^3$	HHV, GJ/t	LHV / HHV	%C	GR, CO_2e $/CO_2$	EF^C, tCO_2e /t	EF^C, tCO_2e $/m^3$
Acetylene		1.10	0.0549	49.9	0.91	92.3	1.0012	3.39	3.73e-3
Asphalt and Road Oil	5.6	1032	44.0	42.6	0.95	83.5	1.0036	3.07	3.17
Aviation Gas	69.0	706	33.5	47.5	0.95	85.0	1.0040	3.13	2.21
Butane (liquid)	111.3	583	28.7	49.2	0.95	82.8	1.0043	3.05	1.78
Crude Oil	30.5	873	38.5	44.1	0.95	84.8	1.0037	3.12	2.73
Distillate Oil (Diesel)	35.5	847	38.7	45.7	0.95	86.3	1.0037	3.18	2.69
Ethane (liquid)	248.3	373	19.4	52.1	0.95	80.0	1.0047	2.95	1.10
Fuel Oil #4	24.1	909	39.9	43.9	0.95	86.4	1.0038	3.18	2.89
Isobutane	120.5	562	27.6	49.1	0.95	82.8	1.0043	3.05	1.71
Jet Fuel	42.0	816	37.6	46.1	0.95	86.3	1.0039	3.18	2.59
Kerosene	41.4	818	37.6	45.9	0.95	86.0	1.0037	3.17	2.59
LPG*	139.4	522	25.7	49.2	0.95	79.9	1.0048	2.93	1.53
Lubricants	25.6	901	40.2	44.6	0.95	85.8	1.0039	3.16	2.84
Miscellaneous Product	30.5	873	38.5	44.1	0.95	85.5	1.0036	3.15	2.75
Motor Gasoline	59.1	742	34.9	47.0	0.95	86.6	1.0042	3.19	2.37
Naphtha*	77.1	678	32.4	47.8	0.95	85.4	1.0047	2.95	1.10
Natural Gas (processed)	-	0.67	0.0380	56.5	0.90	76.0	1.0012	2.79	1.88e-3
Natural Gas (raw)	-	0.67	0.0460	56.5	0.90	76.0	1.0012	2.79	1.88e-3
Natural Gas Liquids (NGLs)**	164.0	479	23.9	50.4	0.95	81.4	1.0044	3.00	1.61
Natural Gasoline	81.7	664	30.7	46.3	0.95	83.7	1.0044	3.08	2.05
Pentanes Plus	81.7	664	30.7	46.3	0.95	83.7	1.0042	3.08	2.05
Petrochemical Feedstocks	67.1	712	34.8	48.8	0.95	84.1	1.0040	3.10	2.21
Petroleum Coke	35.0	850	40.0	47.1	0.95	92.3	1.0028	3.39	0.00
Petroleum Waxes	43.3	810	36.7	45.3	0.95	85.3	1.0039	3.14	2.54
Propane (gas)		1.90	0.0937	49.3	0.92	81.8	1.0005	3.00	5.7e-3
Propane (liquid)	148.4	506	25.4	50.2	0.95	81.8	1.0042	3.01	1.52
Residual Oil #5	17.4	950	41.8	44.0	0.95	88.7	1.0037	3.26	3.10
Residual Oil #6	11.0	993	41.7	42.0	0.95	85.7	1.0037	3.15	3.13
Special Naphtha	51.2	774	34.8	44.9	0.95	84.8	1.0041	3.12	2.42
Still Gas			39.8		0.95	-	1.0043	-	-
Unfinished Oils	30.5	873	38.7	44.3	0.95	85.5	1.0037	3.15	2.75

Table A-1: Default oil and gas product properties [11] (*Naphtha and LPG taken from [12-13], **NGL uses generic composition detailed in [14])

A2 Effective oxidation rates

Fuel	2013 NEU fraction - EU 28	2013 NEU fraction - Global
Aviation gasoline	0.0%	0.0%
Bitumen	100.0%	100.0%
Ethane	100.0%	100.0%
Residual Fuel Oil	19.7%	20.4%
Gas / Diesel Oil	0.8%	0.9%
Gasoline	0.3%	0.4%
Jet Kerosene	0.0%	0.0%
Liquefied Petroleum Gas (LPG)	39.6%	44.4%
Lubricants	100.0%	100.0%
Naphtha	95.9%	95.9%
Other Kerosene	6.8%	8.2%
Other petroleum	94.0%	94.1%
Petroleum Coke	16.4%	16.4%
Petroleum product (wt. average)	15.8%	17.9%
Natural Gas Liquids	*Assumed as petroleum average*	
Oil	*Assumed as petroleum average*	
Plastics	100%	100%
Natural Gas	3%	3%

Table A-2: European and global non-energy use (NEU) fractions [15-17]

Non-energy use fractions of total final consumption were calculated for the EU 28 from detailed energy balances accessed through the Eurostat database [15-16]. Data on NEU consumption is also available from this source at the sectoral level: Industry, Transport, and Other. To adjust for global NEU fractions, EU 28 fractions were reallocated for the global sector energy split. In 2013 an average of 72% of industrial petroleum product consumption was NEU, compared with just 1% in each of the other sectors. Assuming these sector fractions, industry has a 24% share of total final energy consumption at the global level, but a 21% share at the European level. Hence NEU fractions from the EU level have been adjusted upwards for the global level.

Fuel	OF	SF	EO
Aviation gasoline	0.993	-	99.3%
Bitumen	0.988	0.998	0.2%
Ethane	1.000	0.634	36.6%
Residual Fuel Oil	0.988	0.618	86.8%
Gas / Diesel Oil	0.994	0.618	98.9%
Gasoline	0.994	0.767	99.1%
Jet Kerosene	0.997	0.500	99.7%
Liquefied Petroleum Gas (LPG)	0.994	0.740	70.3%
Lubricants	0.996	0.446	55.4%
Naphtha	0.998	0.774	25.8%
Natural Gas Liquids	0.999	0.777	87.7%
Other Kerosene	0.994	0.915	93.2%
Other petroleum	0.992	0.758	28.7%
Petroleum Coke	0.997	0.859	85.7%
Petroleum product (wt. average)	0.994	0.723	88.1%
Natural Gas Liquids	*Assumed as petroleum average*		
Oil	*Assumed as petroleum average*		
Plastics	0.994	0.800	0.0%
Natural Gas	0.997	0.669	97.7%

Table A-3: Global defaults of oxidation factors (OF), storage fractions (SF) and final effective oxidation rate (EO) [18-19]

A3 Standard unit conversions

Energy conversion						
unit per:	Million Btu	GJ	toe	tce	kWh	kcal
Million Btu	1.000E+00	9.478E-01	3.968E+01	2.778E+01	3.412E-03	3.968E-06
GJ	1.055E+00	1.000E+00	4.187E+01	2.931E+01	3.600E-03	4.187E-06
toe	2.520E-02	2.388E-02	1.000E+00	7.000E-01	8.598E-05	1.000E-07
tce	3.600E-02	3.412E-02	1.429E+00	1.000E+00	1.228E-04	1.429E-07
kWh	2.931E+02	2.778E+02	1.163E+04	8.141E+03	1.000E+00	1.163E-03
kcal	2.520E+05	2.388E+05	1.000E+07	7.000E+06	8.598E+02	1.000E+00

Mass conversion					
unit per:	Short Tons	Kilograms	Metric Tons	Long Tons	Pounds
Short Tons	1.000E+00	1.102E-03	1.102E+00	1.120E+00	5.000E-04
Kilograms	9.072E+02	1.000E+00	1.000E+03	1.016E+03	4.536E-01
Metric Tons	9.072E-01	1.000E-03	1.000E+00	1.016E+00	4.536E-04
Long Tons	8.929E-01	9.842E-04	9.842E-01	1.000E+00	4.464E-04
Pounds	2.000E+03	2.205E+00	2.205E+03	2.240E+03	1.000E+00

Volume conversion					
unit per:	Barrels	U.S. gallons	Liters	Cubic feet	Cubic meters
Barrels	1.000E+00	2.381E-02	6.290E-03	1.781E-01	6.290E+00
U.S. gallons	4.200E+01	1.000E+00	2.642E-01	7.480E+00	2.642E+02
Liters	1.590E+02	3.785E+00	1.000E+00	2.832E+01	1.000E+03
Cubic feet	5.615E+00	1.337E-01	3.531E-02	1.000E+00	3.531E+01
Cubic meters	1.590E-01	3.790E-03	1.000E-03	2.832E-02	1.000E+00

Table A-4: Standard conversion tables for energy, mass, and volume

A4 Material flow comparison

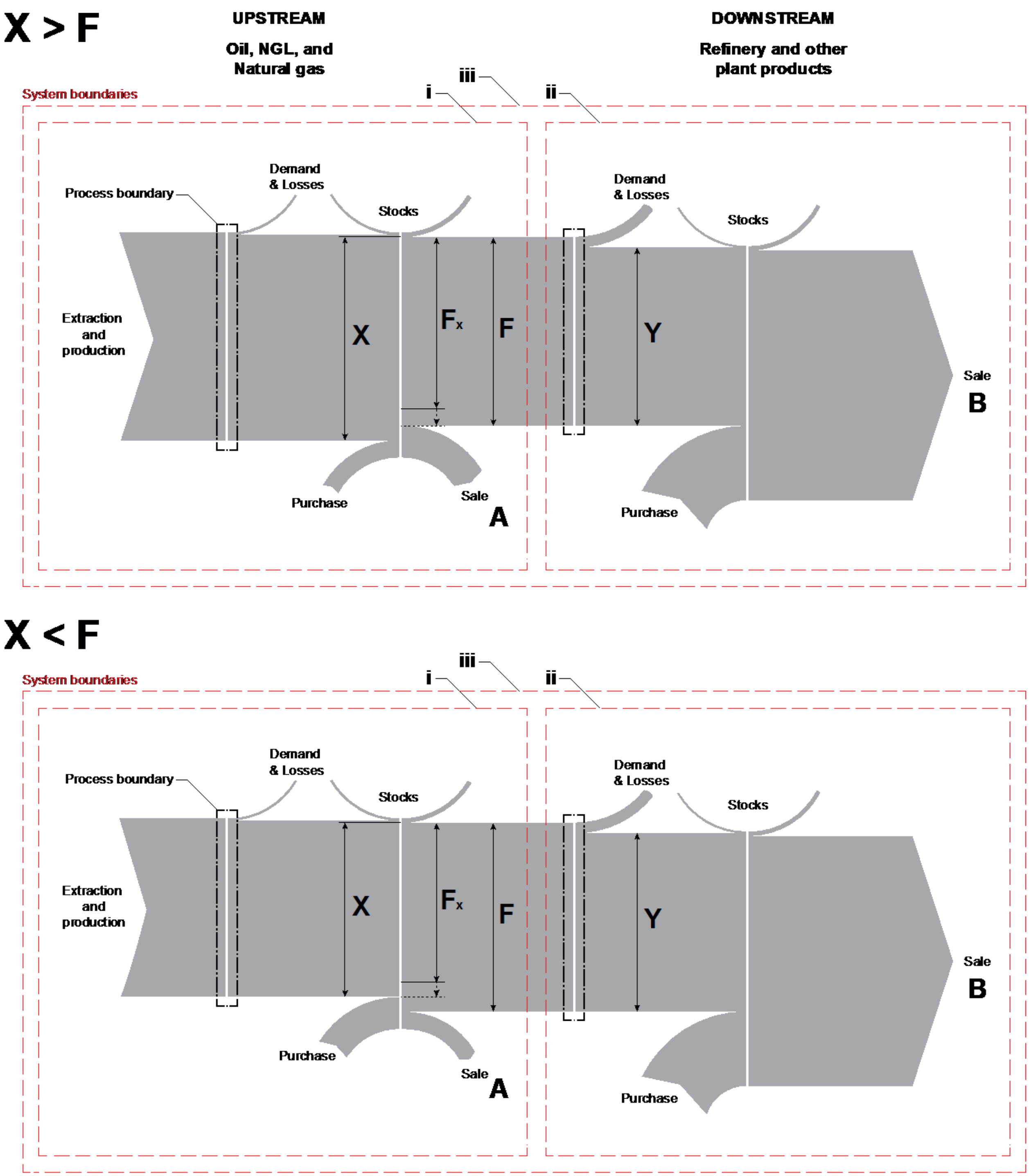

Figure A-1: Sankey diagrams comparing two aggregate material flows through oil and gas companies

A5 Worked example

The worked examples shown in the box below demonstrate a high variability in the results of different approaches for estimating Scope 3 category 11 emissions. This is why it is important that the reporting company is explicit about the method and boundaries chosen in their estimation.

Tier 1 Production method – Total net production ($P = X + Y – F_X$)

In 2015, company A had upstream production of 1,000 thousand barrels per day (mbpd) of crude oil, 200 mbpd of natural gas liquids, and 150 million cubic feet per day (mmcfpd) of natural gas. Refinery production was: 50 mbpd of LPG, 600 mbpd of motor gasoline, 200 mbpd of diesel, 150 mbpd of fuel oil, 60 mbpd ethane, 30 mbpd naphtha, and 30 mbpd of asphalts. Of crude oil and NGL production, 56% and 38% are used as feedstock in company owned refineries. The analyst believes that 100% of asphalts are used for road surfacing and about 50% of naphtha and ethane is ultimately stored in plastic. The analyst is aware that company crude oil is largely of a medium grade, and therefore reasonably represented by the global average EF. The data source has liquid EFs with units $kgCO_2e$/gallon (US), gas EFs with units of $kgCO_2e$/cf. Note that each production figure is net of losses, stock changes and self-consumption for energy.

Unit conversion

$$1 \text{ gallon} = 1 \text{ mbpd} \times 42 \times 10^3 \times 365 = 15.33\times10^6$$

$$1 \text{ cf} = 1 \text{ mmcfpd} \times 10^6 \times 365 = 365\times10^6$$

Calculate emissions

Oil		1,000 mbpd × (1 – 0.56) × 15.33×10^6 × 10.32 $kgCO_2e$/gallon
NGL	+	200 mbpd × (1 – 0.38) × 15.33×10^6 × 5.41 $kgCO_2e$/gallon
Gas	+	150 mmcfpd × 365×10^6 × 0.0545 $kgCO_2e$/cf
LPG	+	50 mbpd × 15.33×10^6 × 5.70 $kgCO_2e$/gallon
Gasoline	+	600 mbpd × 15.33×10^6 × 8.82 $kgCO_2e$/gallon
Diesel	+	200 mbpd × 15.33×10^6 × 10.22 $kgCO_2e$/gallon
Fuel oil	+	150 mbpd × 15.33×10^6 × 11.00 $kgCO_2e$/gallon
Ethane	+	60 mbpd × 50% × 15.33×10^6 × 4.07 $kgCO_2e$/gallon
Naphtha	+	30 mbpd × 50% × 15.33×10^6 × 8.54 $kgCO_2e$/gallon
	=	$228.83\times10^9 kgCO_2e$

Answer should be reported in metric tons (tons) of CO_2e with no commas: **228830000**

Tier 1 Production method – Simplified production (P = X)

Assuming a conversion rate of 5,800 cf per barrel of oil equivalent (boe), Company A has upstream production of 756 mmboe and downstream production of 409 mmboe. Company A is therefore an upstream oriented integrated company. A simplified approach to the production method would be to assume that upstream production is representative of overall net production. In which case the previous calculation is as follows:

Calculate emissions

Oil		1,000 mbpd × 15.33×10^6 × 10.32 $kgCO_2e$/gallon
NGL	+	200 mbpd × 15.33×10^6 × 5.41 $kgCO_2e$/gallon
Gas	+	150 mmcfpd × 365×10^6 × 0.0545 $kgCO_2e$/cf
	=	$177.83 \times 10^9 kgCO_2e$

Answer should be reported in metric tons (tons) of CO_2e with no commas: **177830000 Tier**

1 Sales method (S = A + B)

Company A product sales partially derive from own production. This is reflected in the figures used for the sales method calculation. Note that sales figures exclude sales that do not cross the organizational boundary.

Oil		485 mbpd × 15.33×10^6 × 10.32 $kgCO_2e$/gallon
NGL	+	208 mbpd × 15.33×10^6 × 5.41 $kgCO_2e$/gallon
Gas	+	152 mmcfpd × 365×10^6 × 0.0545 $kgCO_2e$/cf
LPG	+	80 mbpd × 15.33×10^6 × 5.70 $kgCO_2e$/gallon
Gasoline	+	840 mbpd × 15.33×10^6 × 8.82 $kgCO_2e$/gallon
Diesel	+	300 mbpd × 15.33×10^6 × 10.22 $kgCO_2e$/gallon
Fuel oil	+	290 mbpd × 15.33×10^6 × 11.00 $kgCO_2e$/gallon
Ethane	+	70 mbpd × 50% × 15.33×10^6 × 4.07 $kgCO_2e$/gallon
Naphtha	+	41 mbpd × 50% × 15.33×10^6 × 8.54 $kgCO_2e$/gallon
	=	318.33$kgCO_2e$

Answer should be reported in metric tons (tons) of CO_2e with no commas: **318330000**

A6 Unit descriptions

Description	Unit
Volume:	
barrels	bbl
thousand barrels	mbbl
million barrels	mmbbl
billion barrels	Bbbl
trillion barrels	Tbbl
barrels per day	bpd
thousand barrels per day	mbpd
million barrels per day	mmbpd
billion barrels per day	Bbpd
cubic feet	cf
thousand cubic feet	mcf
million cubic feet	mmcf
billion cubic feet	Bcf
trillion cubic feet	Tcf
cubic feet per day	cfpd
thousand cubic feet per day	mcfpd
million cubic feet per day	mmcfpd
billion cubic feet per day	Bcfpd
gallons	gal.
thousand gallons	mgal.
million gallons	mmgal.
billion gallons	Bgal.
trillion gallons	Tgal.
cubic meters	cm
thousand cubic meters	mcm
million cubic meters	mmcm
billion cubic meters	Bcm
trillion cubic meters	Tcm
cubic meters per day	cmpd
thousand cubic meters per day	kcmpd
million cubic meters per day	Mcmpd
billion cubic meters per day	Bcmpd
liters	l
thousand liters	kl
million liters	Ml
billion liters	Bl
trillion liters	Tl
liters per day	lpd
thousand liters per day	mlpd
million liters per day	mmlpd
billion liters per day	Blpd

Description	Unit
Mass:	
tons	t
kilo-tons	kt
mega-tons	Mt
giga-tons	Gt
terra-tons	Tt
peta-tons	Pt
kilo-grams	kg
mega-grams	Mg
giga-grams	Gg
tera-grams	Tg
peta-gram	Pg
exa-gram	Eg
tons, short	ts
kilo-tons, short	kts
mega-tons, short	Mts
giga-tons, short	Gts
terra-tons, short	Tts
peta-tons, short	Pts
tons, long	tl
kilo-tons, long	ktl
mega-tons, long	Mtl
giga-tons, long	Gtl
terra-tons, long	Ttl
peta-tons, long	Ptl
pounds	lb
kilo-pounds	klb
mega-pounds	Mlb
giga-pounds	Glb
terra-pounds	Tlb
peta-pounds	Plb
Energy:	
British thermal units	Btu
thousand British thermal units	mBtu
million British thermal units	mmBtu
billion British thermal units	Bbtu
trillion British thermal units	TBtu
peta-British thermal units	Pbtu
kilo-joules	kJ
mega-joules	MJ
giga-joules	GJ
tera-joules	TJ
peta-joules	PJ
exa-joules	EJ

Description	Unit
barrels of oil equivalent	boe
thousand barrels of oil equivalent	mboe
million barrels of oil equivalent	mmboe
billion barrels of oil equivalent	Bboe
trillion barrels of oil equivalent	Tboe
barrels of oil equivalent per day	boed
thousand barrels of oil equivalent per day	mboed
million barrels of oil equivalent per day	mmboed
billion barrels of oil equivalent per day	Bboed
trillion barrels of oil equivalent per day	Tboed
tons of oil equivalent	toe
kilo-tons of oil equivalent	ktoe
mega-tons of oil equivalent	Mtoe
giga-tons of oil equivalent	Gtoe
kilo-calories	kcal
mega-calories	Mcal
giga-calories	Gcal
terra-calories	Tcal
peta-calories	Pcal
exa-calories	Ecal
kilo-Watt-hours	kWh
mega-Watt-hours	MWh
giga-Watt-hours	GWh
tera-Watt-hours	TWh
peta-Watt-hours	PWh
tons of coal equivalent	tce
kilo-tons of coal equivalent	ktce
mega-tons of coal equivalent	Mtce
giga-tons of coal equivalent	Gtce