IPIECA energy API

Estimating petroleum industry value chain (Scope 3) greenhouse gas emissions

Overview of methodologies

Climate change

THE GLOBAL OIL AND GAS INDUSTRY ASSOCIATION FOR ENVIRONMENTAL AND SOCIAL ISSUES

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A cautionary note regarding performance indicators

Aggregated, company-level, non-financial performance data, developed using this document, can be informative, but significant limitations exist due to various factors including the high degree of uncertainty in the base information and estimation methods available for Scope 3 GHG emissions. Report users are advised to exercise caution when using data from voluntary GHG emissions reports to compare performance. Where this document mentions comparability, it is not intended to imply that data in GHG emissions reports, and therefore companies' performance, are always directly comparable. This is especially important when considering Scope 3 emissions estimates.

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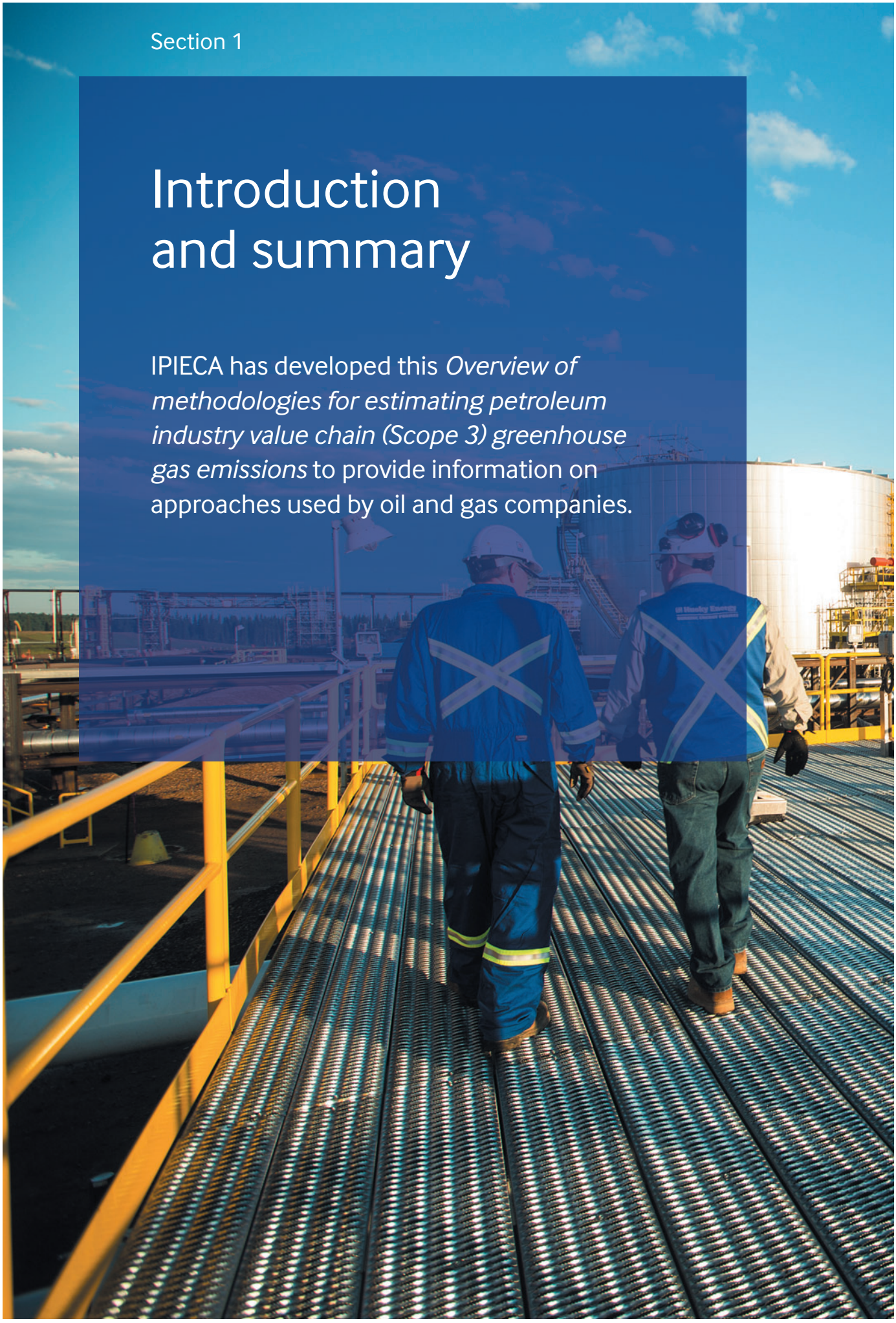
Section 1

Introduction and summary

IPIECA has developed this *Overview of methodologies for estimating petroleum industry value chain (Scope 3) greenhouse gas emissions* to provide information on approaches used by oil and gas companies.



Introduction and summary

1.1 BACKGROUND

Scope 3 emissions are those generated from value chain activities that are not accounted for and reported in the company's scope 1 and 2 corporate inventories. Over the past several years, greenhouse gas (GHG) accounting and reporting has been expanding from focusing on emissions from direct operations to including GHG emissions along the corporate value chains.

In response to the interest in understanding GHGs along a company's value chain, the Greenhouse Gas Protocol, a multi-stakeholder partnership convened by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD), developed the *Corporate Value Chain (Scope 3) Accounting and Reporting Standard* (WRI/WBCSD, 2011; referred to as the 'GHG Protocol Scope 3 Standard') and the associated *Technical Guidance for Calculating Scope 3 Emissions* (WRI/WBCSD, 2013; referred to as the 'GHG Protocol Scope 3 Calculation Guidance'). Improving the understanding of GHG impacts that encompass company-related emissions throughout the value chain allows companies to promote improved management of GHG-related risks and opportunities.

1.2 PURPOSE

The purpose of this *Overview of methodologies* is to provide information on approaches used by oil and gas companies to estimate and account for GHG emissions. Petroleum industry-related scope 3 emission sources, category classifications and associated emissions are highly dependent on company business models, scope 1 and 2 reporting boundaries, and company operations within the value chain. The methodologies in this document outline a number of approaches used by the oil and gas industry to estimate scope 3 emissions. Estimating emissions beyond direct operations involves an increased level of assumptions and uncertainty, and should therefore be considered with caution. The goal of this *Overview of methodologies* is to inform companies about scope 3 GHG emission estimation approaches.

1.3 SCOPE

The estimation methodologies in this document focus on scope 3 emissions. It is intended to inform companies on approaches to estimating value-chain GHG emissions, and complement and provide oil and gas industry context to existing standards and guidance documents including the following:

1. GHG Protocol Scope 3 Standard (WRI/WBCSD, 2011).
2. GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).
3. IPIECA/API/IOGP Sustainability Reporting Guidance, 3rd edition (IPIECA, 2015).
4. IPIECA Scope 1 and 2 Guidance (IPIECA, 2011).
5. American Petroleum Industry (API) *Compendium of Greenhouse Gas Emissions Estimations Methodology for the Oil and Gas Industry* (API, 2009; referred to as the 'Compendium').
6. The GHG Protocol's *A Corporate Accounting and Reporting Standard* (WRI/WBSCD, 2004; referred to as the 'GHG Protocol Corporate Standard').
7. *Addressing uncertainty in oil and natural gas industry greenhouse gas inventories* (IPIECA/API, 2015).

Much of the material contained in this *Overview of methodologies* is based on the GHG Protocol Scope 3 Standard and the GHG Protocol Scope 3 Calculation Guidance, and is either used directly or adapted for inclusion in this document.

The document addresses each of the 15 different scope 3 categories included in GHG Protocol Scope 3 Standard. The details provided are based on specific qualitative and quantitative materiality considerations for relevant GHG emissions for the petroleum industry.

1.4 DOCUMENT OVERVIEW

This *Overview of methodologies* is organized into the following sections:

Section 1, *Introduction and summary* (this section) provides a background to GHG emissions reporting and outlines the purpose and scope of this document.

Section 2, *Overview of Scope 3 emissions estimation*, introduces the 15 scope 3 categories and provides a high-level overview of scope 3 accounting elements including estimating and reporting principles, scopes and organizational boundaries, and tracking emissions over time.

Section 3, *Category-specific considerations*, provides specific information for each category including (1) a description of the category and emissions sources as relevant to petroleum companies, (2) materiality considerations and (3) estimation approaches used by the petroleum industry.

Section 4, *Considerations of optional assurance*, summarizes (1) the key components and the benefits of assurance, (2) the assurance process, (3) levels of assurance and (4) complexities of assuring scope 3 inventories due to the potential uncertainty as compared to scope 1 and 2.

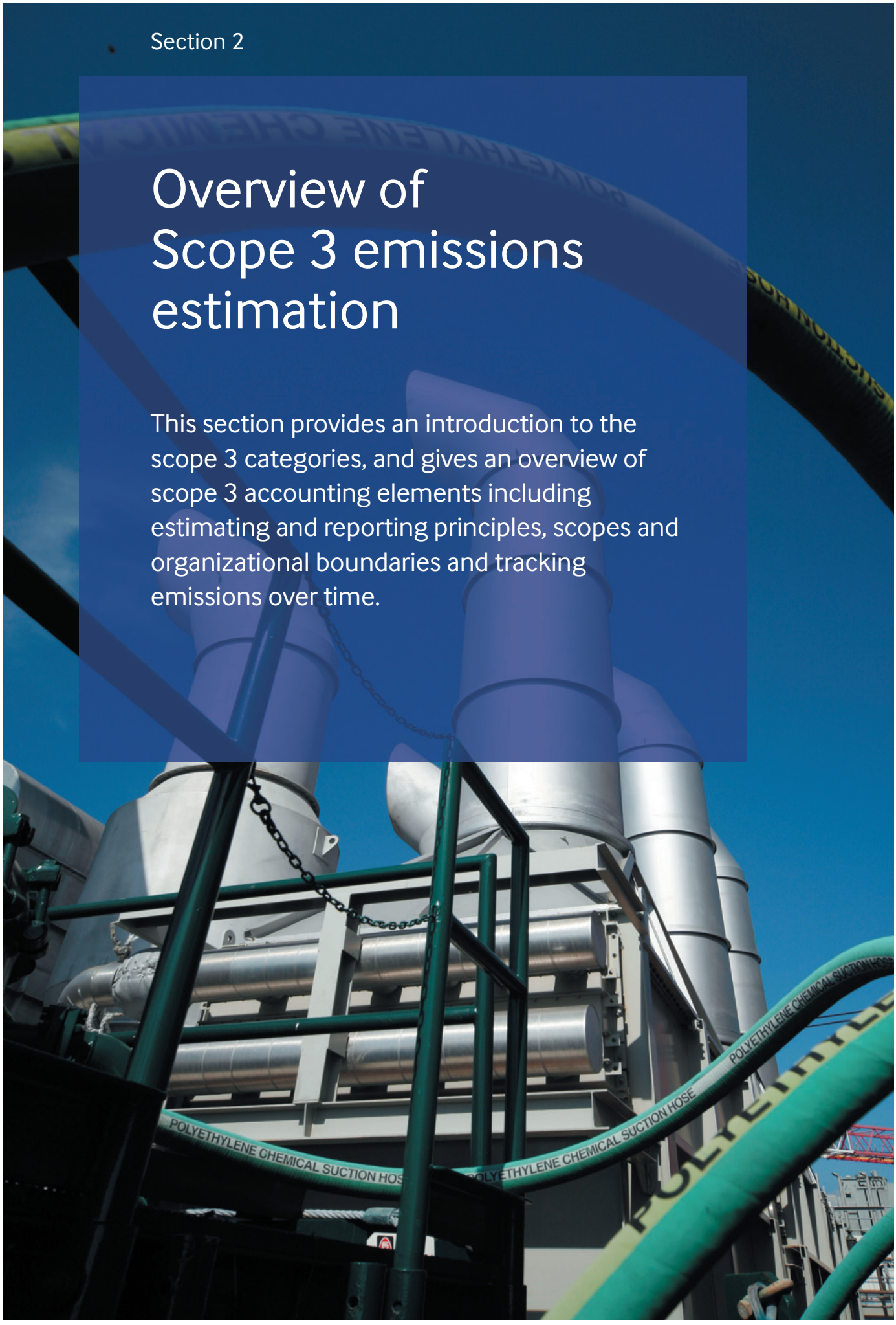
Section 5, *Reporting*, provides a list of potential scope 3 reporting elements and describes how scope 3 reporting fits into the IPIECA/API/IOGP Sustainability Reporting Guidance.

These chapters are followed by a list of references used in developing this publication. The document closes with a glossary of key terms and a list of acronyms and abbreviations.

Section 2

Overview of Scope 3 emissions estimation

This section provides an introduction to the scope 3 categories, and gives an overview of scope 3 accounting elements including estimating and reporting principles, scopes and organizational boundaries and tracking emissions over time.



Overview of Scope 3 emissions estimation

2.0 PETROLEUM INDUSTRY GREENHOUSE GAS ACCOUNTING AND REPORTING PRINCIPLES

Companies often adopt generally-accepted GHG accounting principles to serve as the basis for their environmental accounting and reporting. The following principles are those presented in the IPIECA Scope 1 & 2 Guidance:

Relevance: define boundaries that appropriately reflect the GHG emissions of the organizations and the decision-making needs of the users.

Completeness: account for all GHG emission sources and activities within the chosen organizational and operational boundaries. Any specific exclusions should be stated and justified.

Consistency: use consistent methodologies and measurements to allow meaningful comparisons of emissions over time. Transparently document any changes to the data, methods or any other factors in the time series.

Transparency: address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose assumptions and make appropriate references to the calculations and data sources used.

Accuracy: ensure that estimates of GHG emissions are systemically neither over nor under actual emissions levels, as far as can be judged, and that uncertainties are quantified and reduced as far as practicable. Ensure that sufficient accuracy is achieved to enable users to make decisions with confidence as to the integrity of the reported GHG information.

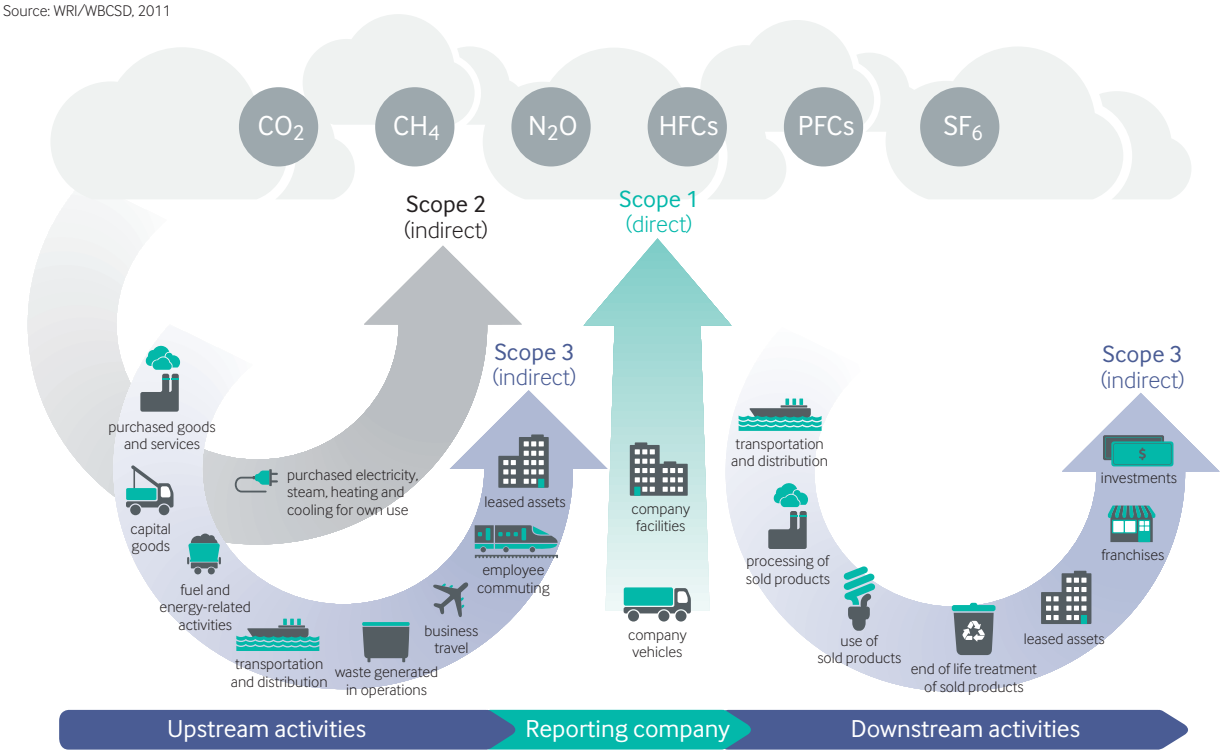
Chapter 2 of the IPIECA Scope 1 & 2 Guidance presents additional details on each of these accounting and reporting principles. These principles are consistent with those presented in the GHG Protocol Scope 3 Standard, GHG Protocol Corporate Standard and the IPIECA/API/IOGP Sustainability Reporting Guidance.

These five principles are broadly applicable to the estimation of scope 3 emissions. In practice, companies may encounter trade-offs between principles when conducting a scope 3 inventory. For example, estimating the scope 3 inventory often involves using less-precise and/or less-accurate data, compared to estimating scope 1 and 2 emissions. Companies balance trade-offs between principles depending on individual business goals and availability of information across the value chain. For example, companies may conduct a high-level screening assessment with less-accurate data to assess a range of scope 3 emissions categories, and focus only on those categories in which they have relatively high emissions, influence or stakeholder interest.

2.1 SCOPES AND ORGANIZATIONAL BOUNDARIES

The GHG Protocol Corporate Standard divides a company's emissions into direct emissions (emissions owned or controlled by the company) and indirect emissions (emissions that are the result of the company's activities, but occur at sources owned or controlled by another company). The GHG Protocol Corporate Standard further classifies emissions into three groups, or 'scopes' as illustrated in Figure 1 on page 11. Scope 1 includes direct emissions, such as fuel combusted at a refinery. Scope 2 includes indirect emissions from finished energy purchases, such as purchased electricity used in facility operations. Scope 3 emissions are emissions that result from value chain activities that are not captured by company scope 1 and scope 2 emissions, such as emissions that result from company-produced fuel used by end-use customers, or the emissions resulting from the production of supplier input products used in company operations (e.g. concrete used in drilling operations).

Figure 1
GHG Protocol scopes and emissions across the value chain
Source: WRI/WBCSD, 2011



Scopes 1, 2 and 3 are mutually exclusive for the company; thus, a company's scope 3 inventory typically does not include any emissions included in a company's scope 1 and 2 emissions. These combined emissions provide an estimate of the company's GHG emissions across the value chain. The scopes are defined so that no companies will double count the same emission source within scope 1 or 2. However, two or more companies may account for the same emissions within scope 3.

For example, emissions from refining operations will be scope 1 for a refinery; these same emissions may be scope 3 emissions for an exploration and production company (for which refining operations represent downstream emissions) and for a petrochemical company (for which refining operations represent upstream emissions). The same scope 3 emissions, particularly for those associated with petroleum product life cycle stages, such as purchased goods (i.e. input materials), transportation, processing and use, could be reported by multiple companies and classified into different scope 3 categories, depending on each company's boundaries and operations. It is important to be mindful of these distinctions when attempting to compare scope 3 emissions among various companies.

Scope 3 GHG estimates depend on a company's organizational and operational boundaries. A company's operational boundary defines the scope of direct and indirect emissions for operations that fall within a company's established organizational boundary.

A company generally has three options for defining its organization boundaries:

- **Equity share:** GHG emissions from operations according to its share of equity in the operations reflecting economic interest.
- **Financial control:** 100 percent of GHG emissions over which a company has financial control. In the case of non-incorporated joint ventures, partnerships, and operations where partners have joint financial control, each partner typically accounts for their proportionate interest.
- **Operational control:** 100 percent of emissions over which a company has operational control

As detailed in the IPIECA Scope 1 & 2 Guidance, companies in the petroleum industry participate in a wide variety of activities, and the way in which companies divide their activities—and thus establish their organizational and operational boundaries—varies among companies. Chapter 3 of the IPIECA Scope 1 & 2 Guidance provides detailed guidance for establishing organizational and operational control boundaries for petroleum industry companies.

Defining the boundaries is a key step in corporate GHG accounting, and companies should use a consistent approach across their scope 1, 2 and 3 inventories. For example, a company that applies an operational control approach to its scope 1 and 2 corporate inventory typically uses an operational control approach, where practical, for defining its scope 3 organizational boundaries. In addition, operations or activities that are excluded from a company's scope 1 and 2 inventories as a result of the organizational boundary definition are typically included in scope 3. For example, if Company X selects the operational control approach, emissions from leased offices controlled by that company may already be included in the company's scope 1 and 2 emissions and, therefore, are not typically addressed in scope 3. However, if Company X excludes from its scope 1 and 2 accounting emissions from investments based on lack of operational control, then those investment emissions are typically included in scope 3.

2.2 TRACKING EMISSIONS OVER TIME

GHG accounting enables companies to track and report emissions over time. Chapter 4 of the IPIECA Scope 1 and 2 Guidance provides details for designing an inventory to track emissions over time for petroleum companies.

Table 1 The 15 categories of Scope 3 emissions

Source: adapted from WRI/WBCSD 2011

1. Purchased goods and services	All cradle-to-gate emissions from the extraction, production, and transport of goods and services not included in categories 2–8.
2. Capital goods	All cradle-to-gate emissions from the extraction, production and transport of capital goods purchased during the accounting year.
3. Fuel and energy	Extraction, production, and transport of purchased fuels and energy, not already accounted for in scope 1 and 2, including extraction, production, and transport emissions of purchased fuels and energy, transmission and distribution losses and generation of purchased energy sold to end users.
4. Upstream transportation and distribution	In this case the term 'upstream' refers to emissions from the transportation and distribution of products (excluding fuel and energy products) purchased or acquired by the reporting company in the accounting year in vehicles and facilities not owned or operated by the accounting company, as well as other transportation and distribution services purchased by the accounting company in the accounting year (including both inbound and outbound logistics).
5. Waste generated in operations	Emissions of waste management suppliers that occur during disposal and treatment of waste generated in the company's operations.
6. Business travel	Emissions of transportation carriers that occur during the transportation of employees for business-related activities.
7. Employee commuting	Transportation of employees between their homes and their worksites.
8. Upstream leased assets	In this case the term 'upstream' refers to operations of assets leased by the company (company is the lessee) not included in scope 1 and scope 2.
9. Downstream transportation and distribution	In this case the term 'downstream' refers to transportation and distribution of products sold by the company between the company's operations and end consumer (if not paid for by the accounting company) including retail and storage.
10. Processing of sold products	Processing by third parties of intermediate products sold by the accounting company.
11. Use of sold products	Direct use-phase emissions of the end use of goods and services sold by the company.
12. End-of-life treatment of sold products	Emission of waste management from the waste treatment and disposal of products sold by the company at the end of their life.
13. Downstream leased assets	In this case the term 'downstream' refers to emissions from the operations of assets owned by the company and leased to other entities, not included in scope 1 and scope 2.
14. Franchises	Emissions from the operations of franchises not included in scope 1 and 2.
15. Investments	Operations of investments in the accounting year not included in scope 1 and 2.

To consistently track scope 3 emissions over time, companies typically note when significant changes occur. Significant changes may include structural changes (mergers, acquisitions or outsourcing), changes in calculation methodology or data accuracy, or changes in the selected categories or activities included in the scope 3 inventory.

2.3 INTRODUCTION TO SCOPE 3 CATEGORIES

2.3.1 Scope 3 category definitions

The GHG Protocol Scope 3 Standard classifies scope 3 emissions into 15 categories (Table 1 on page 12) to provide companies with a systematic framework to organize and understand scope 3 activities across the value chain.

Categorizing emissions sources into each scope 3 category depends on each company's structural and operational approach within the value chain. Figure 2 on page 14 provides an overview of oil and gas industry processes and associated emissions sources. A company's scope 3 emissions will vary depending on which of these processes the company captures in their direct (scope 1) and indirect purchased energy (scope 2) emissions inventories, as well as the company structure and operations.

For example, consider the various ways to account for refinery emissions or for product distribution:

Refinery emissions categorization

- Exploration and production companies: Category 10, processing of sold products.
- Refineries: Scope 1 direct emissions.
- Companies that use refinery products as a feedstock (e.g. petrochemicals): Category 1, purchased goods and services. Similarly, service stations (i.e. retail and marketing) would account for fuel purchases for resale to customers as part of Category 1.
- Companies that purchase and use refinery products as a fuel: Category 3, fuel and energy.

Distribution of oil and gas product emissions categorization

- Companies that own and operate their distribution network: Scope 1.
- Companies that pay for product distribution by third parties: Category 4, upstream transportation and distribution.
- Product distribution not paid for by the accounting company: Category 9: Downstream transportation and distribution.

2.3.2 Scope 3 upstream and downstream emissions

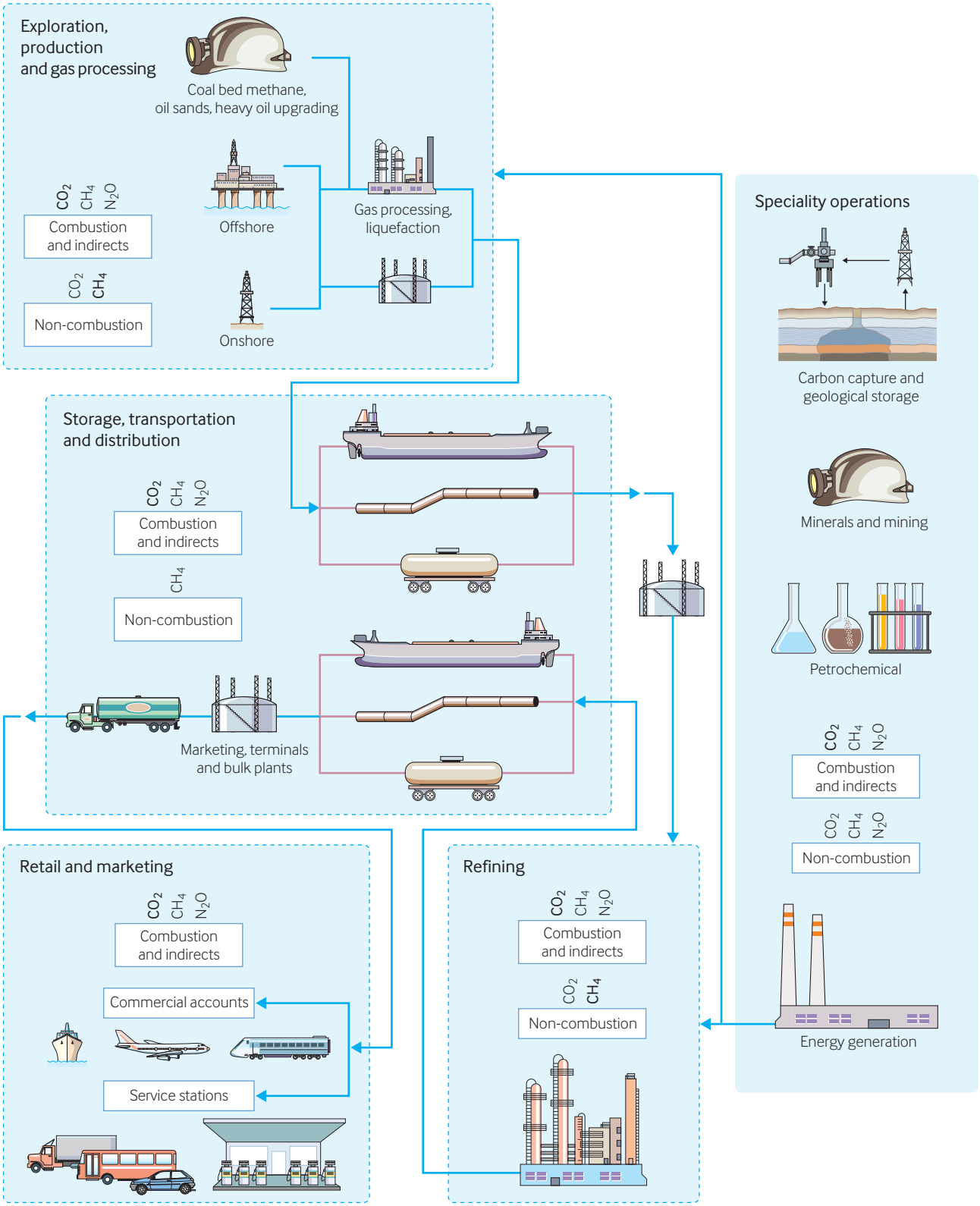
The GHG Protocol Scope 3 Standard divides scope 3 emissions into upstream and downstream emissions based on the financial transactions of the accounting company. The GHG Protocol Scope 3 Standard definitions of upstream and downstream are different from those commonly used in the petroleum industry. Table 2 illustrates how the terms are defined in the context of petroleum industry activities and in the context of Scope 3 emissions. Throughout this *Overview of methodologies*, 'upstream' and 'downstream' refer to the scope 3 definitions as listed in Table 2.

Table 2 Scope 3 and petroleum industry use of the terms 'upstream' and 'downstream'

TERM	SCOPE 3 USE OF TERM	PETROLEUM INDUSTRY USE OF TERM
Upstream	Indirect GHG emissions related to *purchased* or *acquired* goods and services. Refers to Scope 3 categories 1–8.	Activities and/or operations involving the exploration, development, and production of oil and gas.
Downstream	Indirect GHG emissions related to *sold goods* and services. Refers to Scope 3 categories 9–15.	Operations involving the refining, processing, distribution and marketing of products derived from oil and gas, including service stations.

Figure 2 Oil and gas industry GHG emissions

Source: API (2009), p. 2-1



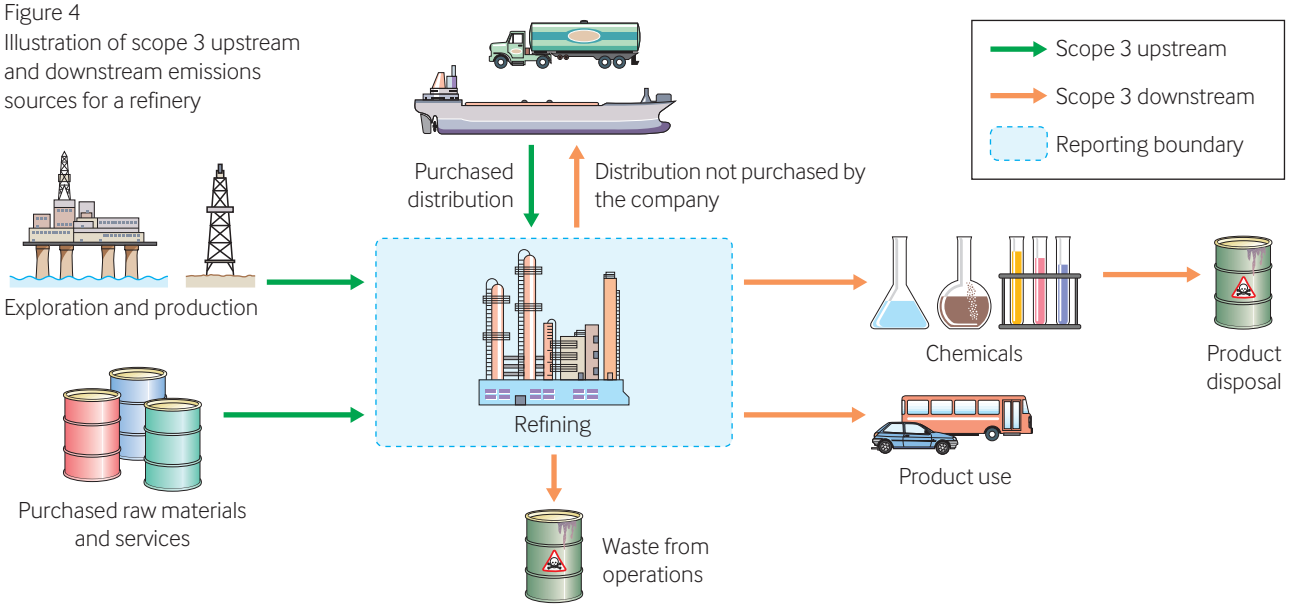
Figures 3 and 4 further illustrate the classification of different types of emissions sources depending on the type of company operations, boundaries, scope and category definitions. These are only a few examples. Companies typically refer to the IPIECA scope 1 and 2 guidance on boundary setting (IPIECA, 2011) to determine when emissions would be considered as scope 1 and 2. Chapter 3 of this *Overview of methodologies* defines each scope 3 emissions category and provides information on emissions sources that oil and gas companies could consider depending on their location in the value chain.

Figure 3 Scope 3 upstream (i.e. purchased or acquired goods and services) and downstream (i.e. sold goods and services) emissions sources by petroleum company type

	COMPANY TYPE				
EMISSION SOURCE	Integrated oil and gas company	E&P company	Refining company	Petrochemical company	Service stations
Purchased raw materials and services	Cat 1, 2	Cat 1, 2	Cat 1, 2	Cat 1, 2	Cat 1, 2
Purchased distribution	Cat 4	Cat 4	Cat 4	Cat 4	Cat 4
Extraction and production	Scope 1 and 2	Scope 1 and 2	Cat 1, 3	Cat 1, 3	Cat 1, 3
Refining operations	Scope 1 and 2	Cat 10	Scope 1 and 2	Cat 1, 3	Cat 1, 3
Waste from operations	Cat 5	Cat 5	Cat 5	Cat 5	Cat 5
External distribution purchased by the company	Cat 9	Cat 9	Cat 9	Cat 9	Cat 9
Product use	Cat 11	Cat 11	Cat 11	Cat 11	Cat 11
Product disposal	Cat 12	Cat 12	Cat 12	Cat 12	Cat 12

Scope 3 upstream emissions: related to purchased or acquired goods and services
Scope 1 and 2 emissions
Scope 3 downstream emissions: related to sold goods and services

Figure 4
Illustration of scope 3 upstream and downstream emissions sources for a refinery



2.3.3 Potential double counting of petroleum-related emissions

The scope 3 categories are designed to be mutually exclusive to eliminate double counting between categories for a specific company. However, because the most common product of the sector is fuel, and emissions Category 11 (use of sold products) captures combustion of fuels, there is a likelihood of double counting fuel combustion accounted for in other scope 3 categories. Most notably, companies that account for liquid fuel products in Category 11 (use of sold products), are at risk of double counting emissions accounted for in Category 4 (upstream transportation), Category 6 (business travel), Category 7 (employee commuting) and Category 9 (downstream transportation and distribution)—all categories where the primary emission source is likely to be the combustion of liquid fuels. Similarly, when estimating for natural gas fuel products, Category 11 emissions may also include emissions in categories where gas use is a factor. For example, natural gas may be used to produce electricity or as a fuel input to manufacture products purchased by the company and thus could be accounted for in Category 1 (purchased goods and services).

To address the issue of double counting, companies may consider:

1. The company does not include fuel emissions in relevant categories (i.e. 4, 6) if those fuel-specific emissions are already included in Category 11.
2. The company includes fuel use emissions in Category 11 and other relevant categories (i.e. 1, 10).

The technical effort required to avoid double counting may be straightforward for some categories and more difficult for others. The effort requires identifying the contribution of fuel emissions to a category, then determining whether those emissions would have already been counted in Category 11. This fuel contribution identification requires matching fuel type to the type of fuel expressed in a category (i.e. if a company only produces natural gas and a category's emissions are from liquid fuels, then there is no double counting between Category 11 and the category in which the liquid fuel is used (e.g. Category 4). The category emissions comparison also requires considering volume, for example if the amount of fuel used in a category is smaller than the amount of that fuel sold by the company included in Category 11, the company may

assume that accounting for fuel emissions in both Category 11 and the other category may be double counting.

Categories for which it may be straightforward to avoid the double counting of Category 11 emissions include Category 4 (upstream transport and distribution), Category 6 (business travel) and Category 7 (employee commuting). For example, a company may illustrate that the jet fuel emissions from fuel that they sell are more than the jet fuel emissions from the fuel used in their Category 6 (business travel) inventory, and they may choose to exclude jet fuel emissions from Category 6 on the basis of double counting. However, segregating fuel emissions from other categories, such as Category 1 (purchased goods and services) may be more difficult. For example, emissions from electricity generation used to produce a purchased good are included in Category 1, and that electricity may be derived from a variety of fuels including natural gas (double counted with Category 11) and coal (not double counted with Category 11), making it difficult to determine the proportion of emissions that are potentially being double counted.

Companies may document the methodology used for addressing if, and where, double counting has potentially occurred, to improve understand and transparency of the resulting information. Further detail is provided as appropriate in category-specific discussions in Section 3.

2.4 SETTING THE SCOPE 3 BOUNDARY

The GHG Protocol Scope 3 Standard was designed to meet the principles of completeness and consistency. It defines scope 3 boundary conditions as follows:

- Companies account for emissions from each scope 3 category and explain any exclusions.
- Companies account for scope 3 emissions of CO_2, CH_4, N_2O and, if relevant, HFCs, PFCs and SF_6[1].
- Biogenic CO_2 emissions in the value chain should not be included in scope 3, but separately accounted for.

While companies strive for completeness, the GHG Protocol Scope 3 Standard acknowledges that including all scope 3 emissions may not be feasible because they are not applicable to company operations (e.g. if a company does not have franchise operations) or not be able to estimate emissions due to a lack of data or other limiting factors.

2.4.1 Materiality

In establishing the boundaries of a scope 3 inventory, companies first determine which activities are material to their GHG inventory. Materiality in this sense indicates that something is material to the GHG inventory. Materiality in this *Overview of methodologies* is fundamentally different from its application in financial accounting information.

[1] Other GHGs, such as NF_3 may be included where companies find them relevant.

Table 3 Considerations for identifying relevant Scope 3 activities

Source: WRI/WBCSD, 2011

CONSIDERATIONS	CRITERIA FOR DETERMINING MATERIAL RELEVANCE
Size	Activities 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	Activities contribute to the company's risk exposure (e.g. climate change-related risks such as financial, regulatory, supply chain, product and customer, litigation, and reputational risks).
Stakeholders	Activities are deemed critical by key stakeholders (e.g. customers, suppliers, investors or civil society).
Outsourcing	Activities are outsourced activities previously performed in-house, or activities outsourced by the accounting company that are typically performed in-house by other companies in the accounting company's sector.
Sector guidance	Activities have been identified as significant by sector-specific guidance.
Other	Activities meet any additional criteria for determining relevance developed by the company or industry sector.

Companies make materiality determinations based on the qualitative and quantitative criteria listed in Table 3. Likewise, the IPIECA/API/IOGP Sustainability Reporting Guidance defines materiality as the issues relevant to both the company and its stakeholders.

Materiality is important in determining which activities a company chooses to include or exclude from its inventory, as well as for establishing the level of effort necessary to estimate those emissions. If a company chooses to include less-material emissions sources, the estimation of those sources may be less rigorous than the estimation of more material sources. While Section 3 of this *Overview of methodologies* provides information to oil and gas companies on which scope 3 emissions are likely to be material, it falls to each individual company to determine which emissions are material to the inventory.

Section 3 includes category-specific descriptions and petroleum industry relevant information on scope 3 category classification, materiality, boundaries and calculation methodologies.

Box 1 Typical reasons for excluding activities

Activities may not be considered material to a company's GHG inventory and may typically be excluded if:

- they are expected to be insignificant in size compared to the company's other sources of emissions; and
- excluding the activity would not compromise the relevance of the reported inventory.

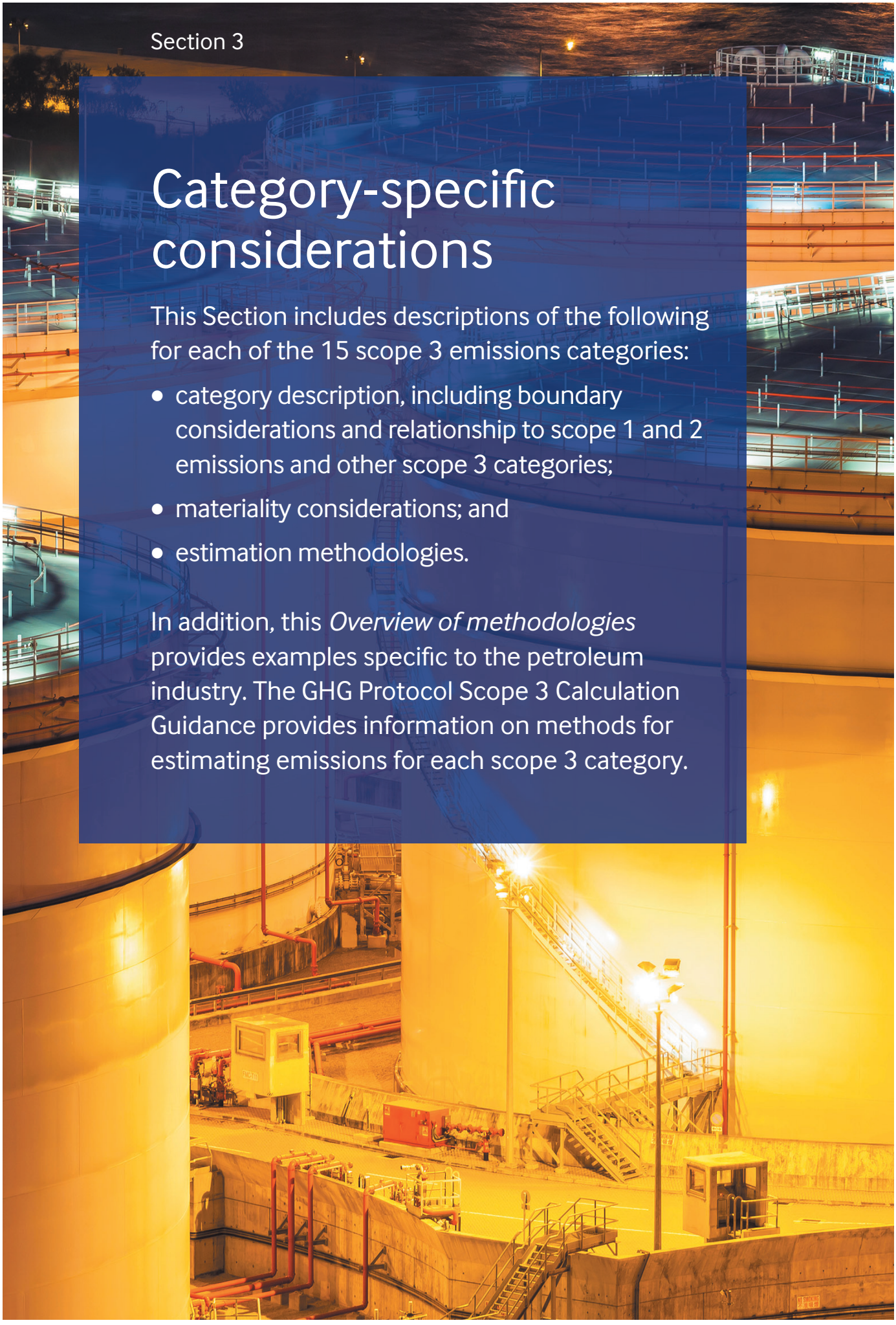
Section 3

Category-specific considerations

This Section includes descriptions of the following for each of the 15 scope 3 emissions categories:

- category description, including boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories;
- materiality considerations; and
- estimation methodologies.

In addition, this *Overview of methodologies* provides examples specific to the petroleum industry. The GHG Protocol Scope 3 Calculation Guidance provides information on methods for estimating emissions for each scope 3 category.



Category-specific considerations

3.0 INTRODUCTION AND BROADLY APPLICABLE CONSIDERATIONS

3.0.1 Prioritizing scope 3 data collection and calculation efforts

Due the diversity of scope 3 emissions sources and the fact that these emissions occur outside the company's boundaries, the emissions estimates may be less accurate or may have high uncertainty. Collecting data for scope 3 emissions estimation may involve wider engagement within the accounting company as well as with suppliers and partners outside the company than is needed for scope 1 and scope 2 calculations. Companies typically prioritize data collection and estimation efforts on the scope 3 activities that are expected to have the most significant GHG emissions, or are otherwise relevant to the accounting company's goals. For oil and gas companies, particularly integrated ones, Category 11 (use of sold products) may be larger than scope 1 and scope 2 emissions inventories combined.

Companies often use a combination of approaches and criteria to identify key focus areas or activities. For example, companies may consider seeking higher quality data for activities that are significant in size, activities that present the most significant risks and opportunities in the value chain, and activities where more accurate data can be easily obtained. Companies may choose to rely on relatively less-accurate data for activities that are expected to have insignificant emissions or where accurate data is difficult to obtain, based on the qualitative criteria described in Table 3.

The GHG Protocol Scope 3 Standard recommends the following approaches for identifying priority activities:

- **Based on the magnitude of GHG emissions:** apply GHG estimation (screening) methods to determine which activities are expected to be most significant in size.
- **Based on financial spend or revenue:** use a financial spend-analysis to rank purchased and sold products by their contribution to the company's total expenditures or revenue. However, companies should note that the financial contribution may not correlate with emissions, as some activities may have a relatively low market value but relatively high emissions. Further, any fluctuations in the commodity markets which may increase the uncertainty of using such a method should be taken into account.
- **Based on qualitative criteria:** prioritize activities most relevant to the company or its stakeholders based on the criteria listed in Table 3 on page 18.

The materiality section in each scope 3 category subsection describes category-specific quantitative and qualitative materiality considerations specific to oil and gas companies.

3.0.2 Overview of quantification methods and data types

Most companies employ one of three main methods for quantifying emissions data: direct emissions measurement; direct volume measurement with calculations; and activity measurement with estimations. Direct emissions measurement and direct volume measurement with calculations involve quantifying emissions data based on direct monitoring, mass balance or stoichiometry. These methods are typically utilized for scope 1 and 2 emissions. Scope 3 emissions typically involve estimating emissions by multiplying activity data by an emissions factor. Activity data is often an estimate of a level of activity that results in GHG emissions. An emission factor is a factor that converts direct volume measurements or activity estimates into GHG emissions data. Table 4 on page 21 provides examples of activity data and corresponding emissions factors.

Table 4 Examples of activity estimates and average emissions factors

EXAMPLES OF ACTIVITY ESTIMATES	EXAMPLES OF EMISSIONS FACTORS
Litres (l) of fuel consumed	Average kg CO_2 emitted per l of fuel consumed
Kilowatt-hours (kWh) of electricity consumed	Average kg CO_2 emitted per kWh of electricity consumed
Kilogrammes (kg) of material consumed	Average kg CH_4 emitted per kg of material consumed
Kilometres (km) of distance travelled	Average metric tonne CO_2 emitted per km travelled
Kilogrammes (kg) of product sold	Average kg N_2O emitted per kg of product sold
Quantity of money spent	Average kg CO_2 emitted per unit of currency spent

Most companies use two types of information to estimate scope 3 emissions:

- **Primary data:** data from specific activities within a company's value chain (e.g. data provided by a supplier).
- **Secondary data:** industry-average data (e.g. from published databases, government statistics, literature studies and industry associations), financial data, proxy data and other generic data.

Companies also use a combination of primary and secondary data to estimate scope 3 emissions based on materiality and data availability, as illustrated in Figure 5.

Due to the challenges to scope 3 emissions estimation, some companies rely on value chain partners to provide information, a lesser degree of influence on information management and knowledge about available information, and a broader need for secondary and tertiary information and assumptions. These challenges contribute to uncertainty in scope 3 estimation. High uncertainty for scope 3 estimations should be identified and understood by users of the information. The IPIECA/API document entitled *Addressing uncertainty in oil and natural gas industry greenhouse gas inventories* (IPIECA/API, 2015) provides additional technical considerations and estimation methods, and notes that higher quality GHG data leads to improved confidence in

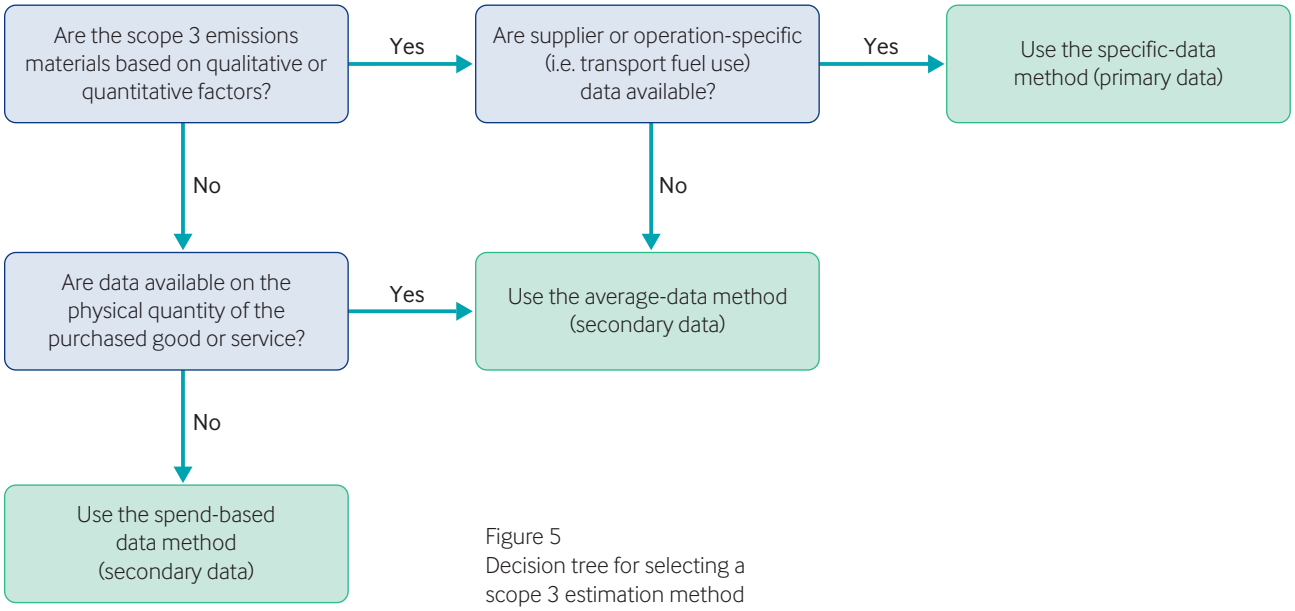


Figure 5
Decision tree for selecting a scope 3 estimation method

the emissions accounted for. Robustness of GHG emissions information depends on four key factors ('the four Cs'): comparability; consistency; certainty; and confidence. Approximations should be based on sound methodologies. In some cases, companies disclose large uncertainty ranges, and if the margin of error is significant, the company may choose not to record specific values until more reliable information becomes available.

3.0.3 Broadly applicable emissions factor references

Along with activity data, emission factors are a key element in estimating scope 3 emissions. This *Overview of methodologies* provides category-specific references for emissions factors applicable to petroleum companies in the category-specific section. In addition, some petroleum companies utilize third-party databases to obtain emissions factors. The GHG Protocol provides a list of third-party databases at www.ghgprotocol.org/Third-Party-Databases.

Table 5 provides examples of third-party datasets that are commonly applied by petroleum industry companies.

3.1 PURCHASED GOODS AND SERVICES

3.1.1 Category description

Purchased goods and services include scope 3 emissions associated with the extraction, production, and transportation of goods and services purchased or acquired by the company, which are not otherwise included in Categories 2–8. Sources of purchased goods and services include: purchased crude oil; natural gas and/or petroleum products used as feedstock or purchased and sold to consumers; purchases of products such as hydrogen used as feedstock; and outsourced activities such as drilling.

Boundary consideration and relationship to scope 1 and 2 emissions and other scope 3 categories

As discussed in section 2.4, sources of purchased goods depend on a company's operations and location in the value chain. Petroleum products purchased as feedstock are a key emission source that petroleum industries typically consider for this category. Table 6 on page 23

Table 5 Commonly applied third-party datasets

REFERENCE [2]	ORIGINAL DATA SOURCES	MAIN TOPICS
Ecoinvent Swiss Centre for Life Cycle Inventories www.ecoinvent.org	Academic research, industry statistics, government publications, other LCA databases	Global process data including: energy carriers and technologies; materials production; systems; end-of-life treatment; transport services; other services; use and consumption; wastes
Economic Input-Output Life Cycle Assessment (EIO-LCA), Carnegie Mellon University www.eiolca.net	Industry statistics	USA, Germany, Spain, Canada and China, environmentally extended input-output analysis (EEIO) input-output data including: energy carriers and technologies; materials production; systems; transport services; other services; end-of-life treatment; wastes
European reference Life Cycle Database (ELCD), European Commission Joint Research Centre eplca.jrc.ec.europa.eu/ELCD3/index.xhtml	Academic research, Industry statistics, government publications, other LCA databases	Europe process information including: end-of-life treatment; energy carriers and technologies; materials production; systems; transport services
U.S. Life-Cycle Inventory Database (USLCI), National Renewable Energy Laboratory (NREL) www.nrel.gov/lci	Academic research	US and global process data including: energy carriers and technologies; materials production; transport services

[2] Reference hyperlinks were active as of the publication date. Links may change as web content is updated.

Table 6 Example sources of purchased goods and services emissions based on company type and process

COMPANY TYPE	OTHER INPUT MATERIALS*	PURCHASED E&P PRODUCTS USED AS FEEDSTOCK	PURCHASED REFINERY PRODUCTS USED AS FEEDSTOCK	PURCHASED PRODUCTS RESOLD TO CONSUMERS	OUTSOURCED SERVICES**
Integrated oil and gas (IO&G) company	✓			✓	✓
E&P company	✓			✓	✓
Refining company	✓	✓		✓	✓
Petrochemical company	✓	✓	✓	✓	✓

* Excluding inputs such as capital goods, included in other categories ** Excluding distribution

illustrates purchased product emissions that different types of companies are likely to include in Category 1.

Other input products include raw material feedstocks used in production, or non-production process-related materials such as office supplies and packaging. Because companies obtain purchased goods and services from hundreds of suppliers, they typically minimize the information collection burden by prioritizing the materials they include based on the materials and services that account for the greatest percentage by spend, mass and/or emission intensity. For example, some oil and gas companies often elect to focus on estimating emissions from hydrogen (a high emission-intensity product) that is produced by third parties as a production process feedstock.

Some petroleum companies choose to include emissions from some outsourced services or products in their scope 1 and 2 emissions instead of in scope 3 in order to maintain consistency with their historical accounting (when sourcing is exclusive to the company's operations). In these cases, companies typically confirm that scope 1 and 2 emissions are not double counted between the oil and gas and the outsourced service company.

Category 1 (purchased goods and services) is intended to capture cradle-to-gate emissions that are not included in the other scope 3 upstream categories. For example, if a 'purchased good' is a capital good, those emissions are typically included in Category 2 (capital goods). Of particular interest to petroleum companies is the distinction between emissions from petroleum product

Table 7 Fuels versus feedstocks scope and category classification[3]

INPUT	CRADLE-TO-SUPPLIER GATE EMISSIONS	TRANSPORTATION FROM SUPPLIER TO ACCOUNTING COMPANY
Purchased petroleum products used as feedstocks	Category 1: purchased goods and services	Category 4: upstream transportation and distribution
Purchased petroleum products used as fuels by the company	Category 3: fuel and energy-related activities	Category 3: fuel and energy-related activities
Fuels and feedstocks produced and consumed by the company	Scope 1	N/A

[3] Consistent with the GHG Protocol Corporate Standard guidance on electricity trading, reporting emissions from fuel purchased for resale to non-end users (e.g. traded) is optional.

feedstocks (typically included in Category 1, purchased goods and services) versus cradle-to-gate emissions for petroleum products that the company uses as fuels (typically included in Category 3, fuel and energy-related activities). In addition, although Category 1 emissions include emissions from the production of purchased products up to the gate of the product manufacturer, this category does not include the transportation of the input product to the company; typically, purchased product transport emissions are noted in Category 4 (upstream transportation and distribution). Table 7 (page 23) illustrates the scope and category into which the cradle-to-gate and transport emissions of fuels and feedstocks are typically classified.

If unable to distinguish what proportion of a purchased product is used for feedstock versus fuel, companies may optionally classify the product as all fuel or all feedstock, and allocate the entire cradle-to-supplier gate emissions for that product to the associated scope 3 category.

Emissions from fuels that are combusted in the production of goods or services will typically be a component of a purchased product's cradle-to-gate emissions (Category 1). Category 1 emissions may therefore be double counted in Category 11 (use of sold products) for companies that sell fuels or products that become fuels. Some companies elect not to include fuel emissions in Category 1 if these fuel-specific emissions are included in Category 11, as illustrated in section 2.3.3. However, it may be difficult to determine the extent to which Category 1 emissions are already presented in Category 11. For example, it could be difficult to determine the proportion of the purchased product's cradle-to-gate emissions that is associated with combustion of the fuels ultimately derived from the company's products versus other emissions sources (e.g. coal used in energy production or process emissions, rather than gas). Alternatively, companies choose to include fuel use emissions in both Category 11 and Category 1, regardless of any overlap, if segregating sold products emissions (Category 11) from Category 1 (purchased goods and services) emissions is deemed too onerous. Similarly, companies that want to be able to understand more fully their Category 1 emissions may account for emissions in both Category 1 and 11, regardless of any overlap. Companies typically describe their strategy for accounting for potential double counting of fuel emissions between scope 3 categories.

3.1.2 Materiality considerations

The purchased goods and services category potentially represents a material proportion of scope 3 emissions depending on a company's location in the value chain and the type and amount of purchased and/or outsourced goods and services it utilizes. In general, emissions from purchased goods and services are more material for companies with operations downstream in the oil and gas value chain, such as retailers and petrochemical companies that do not produce their own oil and gas products, than it is for companies such as those focused on exploration and production. Given the potential materiality of Category 1 emissions, companies typically consider a screening evaluation of Category 1 emissions to determine whether such emissions are material by size at a company-specific level.

3.1.3 Estimating emissions

Oil and gas companies typically use one of the following methods to estimate emissions from purchased goods and services:

- Average-data method: estimate emissions based on the mass or other relevant units of purchased goods multiplied by the relevant secondary (e.g. industry average) emissions sources.
- Spend-based method: estimate emissions by collecting data on the economic value of the goods purchased and multiplying it by the relevant secondary emissions factors.
- Supplier-specific method: collect product-level cradle-to-gate GHG inventory from goods or services suppliers.
- Hybrid method: use a combination of supplier-specific data obtained directly from suppliers on the amount of materials, fuel and electricity used, distance transported and waste generated from the product production multiplied by the appropriate emissions factors, and secondary data to estimate scope 3 upstream emissions wherever supplier-specific data is not available. In many cases it may be difficult to determine with any level of certainty the greenhouse gases associated with purchased feedstocks, products, goods and services.

The average-data and spend-based methods use industry-average data while the supplier-specific and hybrid methods require the accounting company to collect information from suppliers. Further detail for the average-data method and the spend-based methods are described below, as petroleum companies are likely to utilize industry-average data rather than obtain supplier-specific data from the potentially vast range of suppliers.

Average-data method calculation

In this method, companies collect information on the mass or other relevant unit of purchased goods and multiply them by relevant secondary cradle-to-gate emission factors, such as those listed in Table 8 on page 27. Sources for activity information often include internal data systems (e.g. bills of materials) and purchase records.

CO_2e emissions from purchased goods or services =

Sum across purchased goods or services:

∑ (mass of purchased good or service (kg) x

emission factor of purchased good per unit of mass (kg CO_2e/kg))

Spend-based method calculation

In this method, the amount spent on purchased goods is multiplied by the relevant environmentally extended input-output analysis (EEIO) emission factor. The spend-based method is effective for screening purposes and to identify higher impact purchased goods and services for which specific material-based factors could be considered. Companies often use a combination of the average-data based method and spend-based methods.

CO_2e emissions from purchased goods or services =

Sum across purchased goods or service:

∑ (value of purchased goods or service ex.$) x

EEIO emission factor per unit economic value (kg CO_2e/$))

CASE STUDY

Estimating supply chain emissions

Shell Contracting and Procurement has undertaken a study to benchmark the environmental footprint of Shell's supply chain. Results from the study are used to provide an estimate of Shell's Scope 3 emissions from purchased goods and services from Shell's top 200 suppliers by spend.

Shell's supply chain carbon footprint was estimated by multiplying Shell's spend with a supplier as a share of the supplier's revenue by an estimate of the annual GHG emissions of that supplier. The emissions intensity for each supplier was estimated as follows:

- Preference was given to primary data (i.e. Scope 1 and Scope 2 emissions reported directly by the supplier in public references).
- In some cases, where supplier emissions data was not reported, the emissions were estimated from their reported energy consumption in conjunction with appropriate emissions factors.
- In some cases, where the products and services supplied to Shell did not constitute the main business of the supplier, it was decided not to use the primary data.
- Secondary data was used for suppliers where no direct data were available. Preference was given to use of industry averages based on data reported by companies to the Carbon Disclosure Project.
- In other cases, a proxy method (e.g. the emissions of a similar company) was used.

Emission factors

Table 8 on page 27 provides references for factors that companies have applied to estimate or approximate cradle-to-supplier gate emissions from key petroleum industry purchased products in addition to broadly applicable references presented in Table 5 (page 22) and suggested by the GHG Protocol guidance for Category 1 (WRI/WBCSD, 2013). As discussed in section 3.1.1 and illustrated in Table 7 (page 23), emissions from some petroleum products (such as hydrogen and natural gas) have been classified into Category 1 (if the product is used as a feedstock) or Category 3 (if the product is used as a fuel). Companies typically apply emission factors for these types of products as presented in Table 8 to calculate emissions in both Category 1 and Category 3.

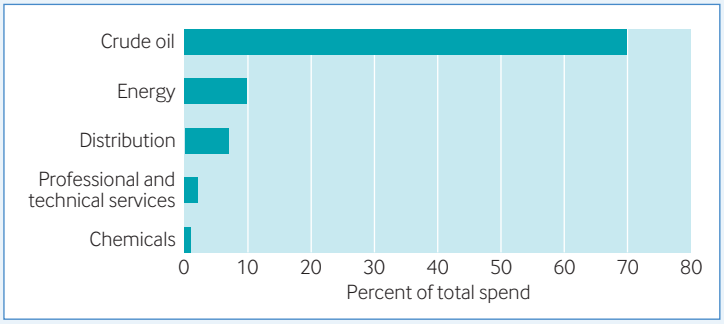
In addition to the references listed in Table 8 and third-party datasets, some companies obtain supplier-specific information using supplier-reported annual emissions.

EXAMPLE 1 Estimating emissions from purchased goods and services by using a combination of the average-data method and the spend-based method

An oil and gas company that purchases 100 million dollars-worth of goods and services ranked their purchases based on total spend and identified those purchases that collectively accounted for more than 90% of their total.

The company accounts for emissions using the following methodology:

- **Crude oil:** crude oil is the company's dominant purchased material. The company obtains its crude oil from multiple suppliers that change over time and supplier-specific data is unavailable. The company estimates emissions based on industry-average mass-based emissions factors.
- **Energy:** included in scope 2 and scope 3 Category 3, fuel and energy-related emissions.



- **Professional and technical services:** the company purchases multiple professional and technical services (e.g. financial, legal) that they group into one general category. They estimate emissions from these professional and technical services based on the spend-based method using sector EEIO information.
- **Chemicals:** the company purchases multiple chemicals, which they group into one general category. They estimate emissions from these chemical purchases based on the spend-based method using general chemical sector EEIO information.
- **Distribution:** included in scope 3 Category 4, upstream transportation and distribution.

Priority purchased product	Amount	Emission factor	Emissions (metric tonnes CO_2e)
Crude oil	700 thousand barrels	27 kg CO_2e/barrel crude oil (cradle-to-gate)	18,900
Professional and technical services	$2 million	117 metric tonnes/million $	234
Chemicals	$1 million	2060 metric tonnes/million $	2,060
Total			**21,194**

Note: The activity data and emissions factors are illustrative only.

Table 8 Emission factor references for purchased goods and services relevant to petroleum companies

REFERENCE	FACTORS INCLUDED	LOCATION
API *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*	Average emission factors for chemical production. Exploration and well testing services emission factors.	www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf
Argonne National Labs. (2014). GREET Model. Geography: Global	Petroleum refinery products (gasoline, diesel, liquefied petroleum gas, naphtha, and residual oil), natural gas (compressed natural gas, liquefied natural gas, liquefied petroleum gas, methanol, dimethyl ester, fischer-tropsch diesel, fischer-tropsch naphtha, hydrogen) and other fuels (coal, landfill gas, biofuels, biomass) emissions by life-cycle stage (well to pump, pump to wheels, vehicle cycle).	https://greet.es.anl.gov/
National Energy Technology Laboratory (NETL). (2009). *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.* DOE/NETL-2009-1346. Geography: North America	Refinery products (conventional gasoline, conventional diesel, kerosene-based jet fuel) emissions by life-cycle stage (raw material acquisition, raw material transport, liquid fuels production, product transport and refuelling, and vehicle/aircraft operation) and by refinery product.	www.netl.doe.gov/energy-analyses/pubs/NETL%20LCA%20Petroleum-Based%20Fuels%20Nov%202008.pdf
National Energy Technology Laboratory (NETL). (2012). Upstream Dashboard Tool. Geography: United States	Crude oil, refinery products (gasoline, jet fuel, diesel) and other fuels (coal, natural gas, uranium, biomass, ethanol) emissions by life-cycle stage (raw material acquisition, raw material transport, and energy conversion facility (ECF)).	www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=551
National Energy Technology Laboratory (NETL). Life Cycle Analysis Unit Process Library Geography: Global	Natural gas—activity data separated by life-cycle stage and fuel type.	www.netl.doe.gov/research/energy-analysis/life-cycle-analysis/unit-process-library
Stanford University (2014). Oil Production Greenhouse gas Emissions Estimator(OPGEE) Geography: United States	Crude oil emissions by life-cycle stage (drilling and development, production and extraction, processing, upgrading, maintenance, waste, diluent, transport)	https://pangea.stanford.edu/researchgroups/eao/research/opgee-oil-production-greenhouse-gas-emissions-estimator

3.2 CAPITAL GOODS

3.2.1 Category description

Capital goods include cradle-to-gate emissions associated with the extraction, production, and transportation of capital goods purchased or acquired by the company. Capital goods are products a company does not immediately consume, but are instead used to manufacture, provide a service, or sell, store and deliver products. Sources of capital good emissions include materials used for company infrastructure such as steel and concrete. Although capital goods (or capital assets) are usually amortized over the life of the asset, companies generally consider the purchase of capital goods in the year of acquisition for scope 3 emissions (WRI/WBCSD, 2011).

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Steel and concrete capital goods, which are high-carbon intensity products, are often the key products petroleum companies consider in Category 2 (capital goods), particularly those companies that are involved with drilling or distribution.

Companies sometimes have difficulty differentiating emissions to include in Category 2 (capital goods—sometimes called 'capital assets') versus Category 1 (purchased goods and services). Capital goods are typically those that have an extended life and are treated as fixed assets or as plant, property and equipment. Companies typically follow their own financial accounting procedures to determine whether to include purchased a product as a capital good in Category 2 or as a purchased good or service in Category 1. Regardless, companies typically try not to double count emissions between scope 3 categories 1 and 2.

Companies generally include only emissions from their own capital assets.

3.2.2 Materiality considerations

Capital goods are not likely to be a material source of emissions in any given year for oil and gas companies. However, significant capital equipment purchases in a given year (such as for construction activity) or qualitative drivers (such as those listed in Table 3) may be considered when estimating capital goods. Multiple qualitative factors can contribute to the potential materiality of the category of capital equipment, primarily in regard to estimating trade-offs between emissions reduction projects and the associated emissions from equipment purchases.

3.2.3 Estimating emissions

The estimation methods for Category 2 (capital goods) are the same as those for Category 1 (purchased goods and services) described in section 3.1.3. These methods include the supplier-specific method, hybrid method, average-product method and a spend-based method. As with Category 1, petroleum companies are likely to apply the average-product and/or spend-based methods utilizing secondary (e.g. industry-average) data.

Emissions factors

Table 9 (page 29) provides references companies typically apply to estimate emissions from key petroleum industry capital goods in addition to those presented in Table 8 on page 27 and those suggested by the GHG Protocol guidance for Category 2 (WRI/WBCSD, 2013).

EXAMPLE 2 Estimating emissions from capital goods based on steel and concrete purchased for major projects

An oil and gas company conducted major projects for which they purchased a variety of capital goods. As a screening assessment, the company selected concrete and steel for inclusion in the capital goods analysis because these materials typically contribute the largest amount of GHG emissions of the materials used in construction. The company estimated their steel and concrete use based on the amounts of the following types of materials purchased:

- concrete foundations and fireproofing;
- steel pilings;
- underground and above-ground steel piping;
- structure steel; and
- rebar in the concrete.

They estimated their Category 2 (capital goods) emissions based on the amount of concrete and steel purchased and cradle-to-gate emissions factors for the materials obtained from life-cycle analysis (LCA) databases. Note that the company includes the emissions associated with transportation of these materials from the supplier to their project site in their Category 4 (upstream transportation and distribution) emissions.

Capital good	Amount	Emission factor	Emissions (metric tonnes CO_2e)
Steel	60,000 metric tonnes	1800 kg CO_2e/metric tonne	108,000
Cement	25,000 m^3	300 kg CO_2e/m^3	7,500
Total			115,500

Note: The activity data and emissions factors are illustrative only.

Table 9 Emission factor references for capital goods and equipment relevant to petroleum companies

REFERENCE	FACTORS INCLUDED	LOCATION
World Steel Association (worldsteel) (2011). *Life Cycle Assessment Methodology Report: Life cycle inventory study for steel products*	Emissions from the processing of fourteen steel industry products from the extraction of raw materials in the ground through to the steel factory gate.	https://www.worldsteel.org/dms/internetDocumentList/bookshop/LCA-Methodology-Report/document/LCA%20Methodology%20Report.pdf
International Stainless Steel Forum (ISSF). Life Cycle Inventory/Analysis of Stainless Steel.	Emissions from the processing of cold roll and white hot rolled steel.	www.worldstainless.org/health_and_environment/life_cycle_inventory_and_analysis
Portland Cement Association (2006). *Life Cycle Inventory of Portland Cement Manufacture.*	Emissions from the manufacturing of cement.	www.nrmca.org/taskforce/item_2_talkingpoints/sustainability/sustainability/sn2095b%20-%20cement%20lci%202006.pdf
University of Bath (2008). *Inventory of Carbon and Energy (ICE).*	Emissions from the manufacturing of cement, concrete, steel, and asphalt.	www.ecocem.ie/downloads/Inventory_of_Carbon_and_Energy.pdf

3.3 FUEL- AND ENERGY-RELATED ACTIVITIES (NOT INCLUDED IN SCOPE 1 OR SCOPE 2)

3.3.1 Category description

Fuel-and energy-related emissions include the cradle-to-gate emissions for fuels and energy purchased or acquired by the company, not already accounted for in scope 1 or scope 2. Category 3 (fuel and energy) includes the following activities:

a. extraction, production and transportation emissions of fuels that are purchased and consumed by the company;
b. extraction, production and transportation of fuels consumed in the generation of purchased energy including electricity, steam and heating. This includes emissions up to the point of, but excluding, combustion by a power generator;
c. transmission and distribution (T&D) losses for purchased electricity; and
d. generation of purchased electricity sold to end users. (generation emissions for purchased electricity used by the accounting company are Scope 2).

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Because many petroleum companies produce fuel and energy products, the emissions that companies include in this category are dependent on company boundaries and operations. For example, companies that produce and consume their own fuels and energy typically do not include emissions from these operations in Category 3, as Category 3 relates only to purchased products. Category 3 fuel and energy-related activities exclude emissions from the combustion of fuels or electricity consumed by the company because those emissions are already included in scope 1 or scope 2. In addition, emissions from the generation of purchased electricity sold to end users (activity 'd', above) are relevant only for those companies that buy and resell electricity to their customers.

Table 10 summarizes the scope and category classifications of emissions of different sources and uses of fuels and electricity. Oil and gas sector companies typically consider purchased fuels and energy in Category 3 fuel and energy-related activities (not included in scope 1 or 2) as being the extraction, processing and transport emissions that are outside their operational boundaries. In addition, companies typically consider the emissions from the generation of electricity, steam, heat and cooling (during extraction, processing, transport and combustion) that is consumed (i.e. lost) in the transmission and distribution system. Extraction, processing and transport of petroleum products that are used as feedstocks (e.g. natural gas used in plastic manufacturing) are typically considered in scope 3 Category 1 (purchased goods and services).

Table 10 Emission scope and category classification based on source and use of fuel and electricity

FUEL TYPE AND SOURCE	END USE	EXTRACTION, PROCESSING AND TRANSPORT	COMBUSTION
a. Purchased fuel	Used on site	Scope 3-Category 3	Scope 1
b. Purchased electricity	Used on site	Scope 3-Category 3	Scope 2
c. Purchased electricity T&D losses	Used on site	Scope 3-Category 3	Scope 3-Category 3
d. Purchased electricity	Sold to customer	Scope 3-Category 3	Scope 3-Category 3
Company-produced fuel	Sold to customer	Scope 1	Scope 3-Category 11
Company-produced fuel	Used on site	Scope 1	Scope 1
Purchased fuel	Sold to customer	Scope 3-Category 1	Scope 3-Category 11

Fuel combustion will typically be a component of the emissions from extraction, processing, and transport of fuel and energy (Category 3). Therefore, Category 3 emissions may double count Category 11 (use of sold products) for companies that sell products that become fuels. Companies have the option not to include fuel emissions in Category 3 if they are included in Category 11 (see section 2.3.3). However, it may be difficult to determine the extent to which Category 3 emissions are already presented in Category 11. For example, if a company sells natural gas that may be used in electricity generation, it could be difficult to determine the proportion of purchased electricity that is derived from gas-fired generation rather than from coal-fired generation (particularly from secondary data sources). Therefore, companies typically choose to include fuel use emissions in both Category 11 and Category 3 if segregating sold products emissions (Category 11) from Category 3 (fuel and energy) emissions is deemed too onerous. Similarly, companies that want to be able to understand more fully their Category 3 emissions typically include these emissions in both Category 3 and 11, regardless of any overlap.

3.3.2 Materiality considerations

Fuel and energy (Category 3) emissions may be material depending on a company's location in the supply chain and on its activities. Emissions from fuel and energy (not included in scope 1 or 2) are not likely to be material for exploration and production companies and integrated oil and gas (IO&G) companies that consume energy that they predominantly produce themselves, e.g. natural gas. Category 3 emissions may be more important for companies that are energy-intensive and purchase their energy. In addition, this category can be material for companies that purchase and resell significant amounts of electricity to end users. Given the potential variability of Category 3 emissions, for petrochemical companies in particular, companies may consider a screening evaluation of Category 3 emissions to determine whether such emissions are material by size at a company-specific level.

3.3.3 Estimating emissions

Oil and gas companies often use one of the methods listed below to estimate emissions from Category 3 activities not included in scope 1 or scope 2 for the four fuel and energy-related activities listed in 3.3.1 (page 30):

- Activities 'a' and 'b': extraction, production and transportation (e.g. 'embodied') emissions from purchased fuels and purchased electricity:
  - *Average-data method:* estimate emissions using secondary (e.g. industry average) emission factors for extraction, production and transportation emission per unit of consumption (e.g. kg CO_2e/kWh).
  - *Supplier-specific method*: collect data from fuel or electricity providers on extraction, production and transportation emissions of fuels or electricity consumed by the company.
- Activity 'c': emissions from transmission and distribution losses:
  - *Average-data method:* estimate life-cycle emissions using average T&D loss rates (e.g. national, regional, or global average depending on data availability).
  - *Supplier-specific method:* collect life-cycle emissions data from electricity providers applied to T&D loss rates of grids where electricity is consumed by the company.
- Activity 'd': emissions from power that is purchased and sold:
  - *Average-data method:* estimate emissions based on grid average life-cycle emission rates.
  - *Supplier-specific method:* collect life-cycle emissions data from power generators.

Companies often leverage data used for their scope 1 and scope 2 inventory to determine the quantities and types of fuel consumed. A valuable source for obtaining T&D loss rates by country is the World Bank database (2014).

Activity 'a': CO_2e emissions from extraction, production and transportation of purchased fuels (consumed by the accounting company) =

Sum across each fuel type consumed:

$+ \sum$ (fuel consumed) (e.g. m^3) x

extraction, production and transportation fuel emission factor (kg CO_2e/m^3)

where:

extraction, production and transportation = life-cycle emission factor − combustion emission factor.

Activity 'b': CO_2e emissions from extraction, production and transportation of fuels consumed in the generation of purchased energy ('embodied' emissions) =

Sum across suppliers, regions or countries:

∑ (electricity consumed (kWh) x embodied electricity emissions emission factor (kg CO_2e/kWh)

+ ∑ (steam consumed (kWh) x embodied steam emissions emission factor (kg CO_2e/kWh)

+ ∑ (heating consumed (kWh) x embodied heating emissions emission factor (kg CO_2e/kWh)

+ ∑ (cooling consumed (kWh) x embodied cooling emissions emission factor (kg CO_2e/kWh)

where:

embodied energy emission factor =

life-cycle emission factor –

combustion emission factor –

T&D losses*

(* T&D losses should be subtracted only if they are included in the life-cycle emission factor.)

Activity 'c': CO_2e emissions from transmission and distribution losses =

Sum across suppliers, regions or countries:

∑ (electricity consumed (kWh) x electricity life-cycle emissions emission factor (kg CO_2e/kWh) x T&D loss rate (%)

+ ∑ (steam consumed (kWh) x steam life-cycle emissions emission factor (kg CO_2e/kWh) x T&D loss rate (%)

+ ∑ (heating consumed (kWh) x heating emissions life-cycle emission factor (kg CO_2e/kWh) x T&D loss rate (%)

+ ∑ (cooling consumed (kWh) x cooling life-cycle emissions emission factor (kg CO_2e/kWh) x T&D loss rate (%)

Activity 'd': CO_2e emissions from power that is purchased and sold =

Sum across suppliers, regions, or countries:

∑ (electricity purchased for resale (kWh) x electricity life-cycle emission factor (kg CO_2 e/kWh)

+ ∑ (steam purchased for resale (kWh) x steam life-cycle emissions emission factor (kg CO_2e/kWh)

+ ∑ (heating purchased for resale (kWh) x heating emissions life-cycle emission factor (kg CO_2 e/kWh)

+ ∑ (cooling purchased for resale (kWh) x cooling life-cycle emissions emission factor (kg CO_2/kWh)

Emission factor boundaries

Different activities within Category 3 are associated with different energy life-cycle stages, and thus use the following emission factor boundaries:

a) Purchased fuel consumed by the company: life-cycle emissions minus combustion emissions.

b) Purchased electricity used by the company: life-cycle emissions minus combustion emissions.

c) Transmission and distribution (T&D) losses: life-cycle emissions.

d) Purchased electricity sold to end users: life-cycle emissions.

Combustion emissions of purchased fuel and energy products that are used by the company are already captured in scope 1 and 2, respectively, so emissions factors for purchased fuel consumed by the company are typically excluded from combustion emissions. However, because emissions from T&D losses are not typically included in scope 1 and 2, the full life-cycle emission factor (extraction, production, transportation and combustion) often includes these emissions in scope 3. Likewise, the full life-cycle emission factor should be applied to resold power to account for the extraction, production, and transportation and combustion activities.

EXAMPLE 3 Estimating Category 3 fuel and energy-related emissions complementary to scope 1 and 2 emissions

A refining company determines its scope 1 and 2 emissions based on the amount of electricity and fuel consumed in its operations: 10,000 metric tonnes of the company's emissions are generated from purchased electricity, and 30,000 metric tonnes from purchased natural gas used as fuel in the company's operations. The Category 3 emissions for purchased natural gas and electricity are estimated based on the ratio of combustion emissions to life-cycle emissions factors (EF), where:

$$\text{Category 3 natural gas emissions} = \frac{\text{Natural gas Scope 1 emissions}}{\text{\% of life-cycle natural gas EF from combustion)}} - \text{Natural gas Scope 1 emissions}$$

$$\text{Category 3 electricity emissions} = \frac{\text{Scope 2 emissions}}{\text{\% of life-cycle electricity EF from combustion}} - \text{Scope 2 emissions}$$

$$\text{Category 3 T\&D loss emissions} = \frac{\text{Scope 2 emission} \times \text{T\&D Loss Rate}}{\text{\% of life-cycle electricity EF from combustion}}$$

Estimation of Category 3 fuel and energy-specific emissions from scope 1 and 2 emissions

	Scope 1 and 2 emissions (metric tonnes CO_2e)	% combustion emission of total life-cycle emissions	Scope 3 Category 3 emissions (metric tonnes CO_2e)
Purchased natural gas consumed by the company	30,000	85%	5,294
Purchased electricity used by the company	10,000	90%	1,111
7% T&D Losses	0		778
Totals:	**40,000**		**7,183**

Note: values are for illustration purposes only.

Table 8 on page 27 provides references to emission factors that companies often apply to estimate emissions from petroleum industry fuels. Additional detail, examples and emission factor resources for estimating Category 3 fuel and energy-related activities are available in Chapter 3 of the GHG Protocol Calculation Guidance (WRI/WBCSD, 2013).

3.4 UPSTREAM TRANSPORTATION AND DISTRIBUTION

3.4.1 Category description

Scope 3 Category 4 (upstream transportation and distribution) emissions include transportation and distribution of products from a company's tier 1 suppliers, and include transportation and distribution services purchased by the company, including inbound logistics, outbound logistics, and transportation and distribution between a company's own facilities. Sources of Category 4 emissions include truck, rail, marine and pipeline transport of input materials (excluding consumed fuels) as well as pipeline distribution, rail, truck and marine transportation of sold products paid for by the company. Note that because this category includes transport of sold products paid for by the company, it can include emissions that are downstream of the accounting company through product distribution.[4]

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Companies often classify emissions from transportation and distribution activities depending on the product transported, if the company purchases these services, and where in the value chain the transport occurs. Table 11 summarizes the category classifications of emissions from transportation and distribution activities in the value chain.

A majority of Category 4 (upstream transportation and distribution) emissions are typically captured in Category 11 (use of sold products) by companies that include emissions from transportation fuels such as gasoline, diesel and jet fuel in their Category 11 emissions, and could therefore be double counted. Some companies choose not to include transportation fuel emissions in Category 4 if these fuel combustion emissions are already included in Category 11. Alternatively, if companies want to more fully understand emissions that result from Category 4 activities, or if

Table 11 Scope and category classification of transportation and distribution activities in the value chain

TRANSPORTATION AND DISTRIBUTION ACTIVITY	SCOPE AND CATEGORY
Transportation and distribution in vehicles and facilities owned or controlled by the accounting company. For consistency, companies may choose to include outsourced distribution in Scope 1 and 2 instead of scope 3 if they have historically done so.	Scope 1 (fuel) Scope 2 (electricity)
Transportation and distribution of inputs other than fuel or energy products purchased by the company, from a company's tier 1 supplier to its own operations.	Scope 3, Category 4: Upstream transportation and distribution
Transportation and distribution services purchased by the company, including inbound logistics and outbound logistics (e.g. of sold products).	Scope 3, Category 4: Upstream transportation and distribution
Transportation and distribution of purchased products (other than fuel or energy products consumed by the company) upstream of a company's tier 1 suppliers.	Scope 3, Category 1: Purchased goods and services (these emissions are already included in the cradle-to-gate emissions)
Transportation of purchased fuels and energy consumed by the accounting company.	Scope 3, Category 3: Fuel and energy-related emissions not included in scope 1 or 2
Transportation and distribution of products sold by the accounting company to the customer (if not paid for by the accounting company).	Scope 3, Category 9: Downstream transportation and distribution
Transportation and distribution in vehicles and facilities leased by and operated by the company (not already included in scope 1 or scope 2).	Scope 3, Category 8: Upstream leased assets

[4] Companies can potentially misclassify purchased downstream transport services into Category 9: Downstream transportation.

segregating sold products emissions (Category 11) from Category 4 (upstream transportation and distribution) emissions is deemed too onerous, companies may choose to include fuel use emissions in both Category 11 and Category 4, regardless of any overlap.

3.4.2 Materiality considerations

Emissions from Category 4 are typically small when transportation and distribution emissions are already captured in scope 1 accounting. These emissions can be material, especially in cases where oil, gas, and finished product transport and distribution paid for by the accounting company are significant. Pipeline transport may be particularly relevant for oil and gas extraction, petroleum refineries, natural gas distribution, and petroleum lubricants, oil and grease manufacturing; truck transport may be particularly relevant for drilling oil and gas wells, and petroleum lubricant, oil and grease manufacturing.

3.4.3 Estimating emissions

Oil and gas companies typically use one of the following methods to estimate emissions from Category 4 (upstream transportation and distribution):

- **Distance-based method:** estimate the mass, distance, and mode of each shipment and apply the appropriate mass-distance emission factor for the mode of transport used.
- **Spend-based method:** estimate the amount of money spent on each mode of travel and apply secondary (EEIO) emission factors.
- **Fuel-based method:** estimate the amount of fuel consumed and apply emissions for the specific fuels.

The distance-based and spend-based methods are described below. Fuel use information is less likely to be available for Category 4 estimations. The fuel-based method is best applied if the vehicle exclusively ships the accounting company's purchased goods (i.e. exclusive use or truckload shipping, rather than less-than-truckload shipping). Otherwise, emissions should be allocated between goods shipped for the accounting company and goods shipped for other companies. If data required for allocation are not available or reliable due to the variety of the goods transported in one vehicle at the same time, the distance-based method may be used to estimate scope 3 emissions.

Distance-based method estimation

In this method, the distance travelled is multiplied by the mass or volume of goods transported times the associated emissions factor that incorporates average fuel consumption, average utilization, average size and mass or volume of the goods and the vehicles. Emissions factors for this method are typically represented in grams or kilograms of CO_2e per tonne-kilometre or TEU-kilometre[5] and are dependent on the type and capacity of the vehicle. When selecting an emission factor for the distance-based method estimation, companies typically consider the vehicle size and capacity (e.g. container vessel >80000 TEU; container vessel 5000–8000 TEU). In addition, some companies consider the percent laden of their vehicles. For example, the Department for Environment Food & Rural Affairs (DEFRA) Greenhouse Gas Conversion Factor Repository (www.ukconversionfactorscarbonsmart.co.uk) freighting goods factors include options for emissions factors based on 0% (vehicle is not transporting any goods), 50% (vehicle is half full of goods), 100% (vehicle has been loaded to maximum capacity), and average laden (average percent laden for a vehicle in the UK) parameters.

Amounts of materials can be tracked using purchase or sales records or internal management systems. The distance travelled can be obtained from suppliers or product distribution companies, or estimated based on the distances to customer locations obtained from maps.

CO_2e emissions from transportation =

Sum across modes and/or vehicle types:

$\sum$ (mass or volume of goods purchased (metric tonne or volume)* x

distance travelled in transport leg (km or m^3) x

emission factor of transport mode or vehicle type ($kg\ CO_2e$/tonne or volume-km))

(* Includes products distributed by outbound logistics companies purchased by the company.)

[5] Tonne-kilometre is a unit of measure that represents one tonne of goods transported over one kilometre. TEU-kilometre is a unit of measure representing one twenty-foot container equivalent of good transported over 1 kilometre (e.g. for sea transport).

Spend-based method estimation

In this method, the amount spent on transportation by type is multiplied by the relevant EEIO emission factors. Some companies determine the amount spent on transportation through bills, invoice payments and financial accounting systems. The spend-based method is effective for screening purposes.

CO_2e emissions from transportation =

Sum across transport modes and/or vehicle types:

∑ (amount spent on transportation by type (e.g. $) x EEIO emission factor per unit economic value (kg CO_2e/$))

Additional detail, examples and emission factor resources for applying upstream transportation and distribution estimation methods are available in Chapter 4 of the GHG Protocol Calculation Guidance (WRI/WBCSD, 2013).

3.5 WASTE GENERATED IN OPERATIONS

3.5.1 Category description

Category 5 (waste generated in operations) emissions result from the disposal and treatment of waste generated in the company's operations. Sources of waste emissions include process wastes sent to landfill, incineration, or waste water that is treated off-site and not included in the company's scope 1 and 2 emissions.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Companies that have on-site waste processing operations, such as a waste-water treatment or incineration, typically include these emissions in their scope 1 and 2 boundary. Companies may include emissions from the transportation of waste sent off-site in Category 5.

The GHG Protocol Scope 3 Standard notes that companies should not account for emissions from recycling processes in Category 5. Some companies recycle some of their operational waste or send the waste to an off-site waste-to-energy facility to be used as a fuel. In these cases, the emissions associated with recycling the material or combusting the waste-derived fuel are typically not included in the company inventory. The GHG Protocol Scope 3 Standard applies the 'recycled content method' to account for emissions from recycling. This method allocates the recycling emissions to the user of the recycled material. If a waste is combusted off-site without energy recovery, companies often include waste incineration emissions in Category 5. If a company incinerates operations waste on-site, those emissions are included in scope 1.

Consideration of how recycling and waste to energy emissions are managed raises questions about the treatment of avoided emissions. For example, a company could determine the avoided emissions associated with displacing other fuels, such as natural gas, with waste-derived fuel or the recycling emissions savings relative to the emissions from producing the equivalent virgin material. Any claims of avoided emissions (claims beyond a reduction in processing emissions) associated with recycling or waste-to-energy are typically not included in, or deducted from, the company's scope 3 emissions, but instead are accounted for separately from scope 1, scope 2 and scope 3 emissions. Accounting for such reductions requires a project-based accounting methodology as described in *The GHG Protocol for Project Accounting* (WRI/WBCSD, 2005).

3.5.2 Materiality considerations

Waste generated in operations is a relatively minimal scope 3 emissions source across petroleum sectors with neither notable qualitative drivers nor relative magnitude.

Some companies estimate waste emissions if stakeholders identify waste emissions as a key consideration. Multiple stakeholders have demonstrated interest in wastes associated with the oil and gas industry. For example, The Railroad Commission of Texas (2001) Texas Railroad Commission Waste Minimization Program provides guidance to increase source reduction and recycling in the exploration and production of oil and gas. Changing the amount of waste subject to management can change associated GHG emissions.

3.5.3 Estimating emissions

Some companies use one of the following methods to estimate emissions from waste generation:

- **Waste-type specific method:** apply emission factors based on specific waste-types and waste-type specific disposal methods (e.g. waste A is sent to a landfill, waste B is incinerated).
- **Average-data method:** estimate emissions based on total waste to each disposal method (e.g. landfill) and average emission factors for each disposal method.
- **Supplier-specific method:** collect waste-specific scope 1 and 2 emissions data directly from waste treatment companies.

The waste-type specific method and average-data method are described below. Supplier-specific information is less likely to be available for petroleum companies. Companies may include emissions from the transportation of waste (refer to section 3.4.3 for transportation calculation methodologies).

Waste-type specific method

Emissions from waste depend on the type of waste being disposed of and the waste diversion method. For this method, companies typically determine:

- the types and associated amounts of waste produced in their operation; and
- for each waste type, the specific waste treatment method used (e.g. landfill, incineration, recycled, wastewater treatment).

Companies may obtain data from waste management invoices and/or from internal environmental management systems.

CO_2e emissions from waste generated in operations =

Sum across waste types:

$\sum$ (waste produced (e.g. metric tonne) x

waste type and waste treatment specific emission factor ($kg\ CO_2e$/metric tonne))

Average-data method

If the type of waste produced is unknown, some companies estimate waste emissions based on total diversion rates from their organization. For this method, companies typically determine:

- the total mass of waste generated in operations; and
- the proportion of waste that is treated by different methods (e.g. landfill, incineration, recycled).

Companies may obtain data from waste management invoices and/or from internal environmental management systems.

CO_2e emissions from waste generated in operations =

Sum across waste treatment methods:

$\sum$ (total mass of waste (metric tonne) x

proportion of total waste being treated by the waste treatment method x

emission factor of waste treatment method ($kg\ CO_2e$/metric tonne))

Additional detail, examples and emission factor resources for applying generated waste estimation methods are available in Chapter 5 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.6 BUSINESS TRAVEL

3.6.1 Category description

Business travel emissions include transportation of employees for business-related activities in vehicles owned or operated by third parties. Sources of business travel emissions can include air, rail and rental car travel. Some companies include emissions from hotels used by business travellers if they are material to the company.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories:

There are no specific petroleum-industry boundary considerations for this category.

Emissions from employee transportation typically fall into multiple scopes and categories, as illustrated in Table 12 on page 38.

Table 12 Scope and category classification of emissions associated with employee transportation

EMPLOYEE TRANSPORTATION ACTIVITY	SCOPE AND CATEGORY
Transportation in vehicles owned or controlled by the accounting company	Scope 1 (fuel) Scope 2 (electricity)
Transportation of employees for business-related activities in vehicles owned or operated by third parties, including rental cars used for business-related activities	Scope 3, Category 6: business travel
Transportation to and from work	Scope 3, Category 7: employee commuting
Transportation in vehicles leased by and operated by the company (not already included in scope 1 or scope 2)	Scope 3, Category 8: upstream leased assets

The majority of Category 6 (business travel) emissions may be captured in Category 11 (use of sold products) by companies that include emissions from transportation fuels such as jet fuel in their Category 11 emissions, and could therefore be double counted. Some companies choose not to include transportation fuel emissions in Category 6 if these fuel combustion emissions are already included in Category 11. For example, a company could demonstrate that emissions from jet fuel in Category 6 are less than the emissions estimated for jet fuel in Category 11. Alternatively, if companies want to more fully understand emissions that result from Category 6 activities, or if segregating sold products emissions (Category 11) from Category 6 (business travel) emissions is deemed too onerous, companies typically choose to include fuel use emissions in both Category 11 and Category 6 regardless of any overlap.

3.6.2 Materiality considerations

Business travel is typically a relatively minimal scope 3 emissions source.

3.6.3 Estimating emissions

Oil and gas companies typically use one of the following methods to estimate emissions from business travel:

- **Distance-based method:** estimate the distance and mode of business trips, and apply appropriate emission factors for the mode used.
- **Spend-based method:** estimate the amount of money spent on each mode of business travel and apply Environmental-extended input-output (EEIO) emission factors.
- **Fuel-based method:** estimate the amount of fuel consumed during business travel by transport providers and apply appropriate emissions factors for that fuel.

Further detail for the distance-based and spend-based methods is described below. Fuel use information is less likely to be available for business travel emissions estimations. The business travel activity data required for these estimations is likely available from travel vendors and internal expense and reimbursement systems. In some cases, travel providers can supply estimated business-related GHG emissions data directly.

Distance-based method estimation

CO_2e emissions from business travel =

Sum across vehicle types:

$\sum$ (distance travelled by vehicle type (by vehicle-km or person-km) x vehicle-specific emission factor (CO_2e/vehicle-km or CO_2e/person-km))

+

(optional)

Sum across hotel types:

$\sum$ (number of hotel nights x hotel emission factor (kg CO_2e/night))

A valuable source for obtaining emissions factors for air travel based on passenger miles is the Department for Environment Food & Rural Affairs (DEFRA) Greenhouse Gas Conversion Factor Repository, accessible from www.ukconversionfactorscarbonsmart.co.uk. It is important to note that air travel factors vary depending on whether they include distance uplift (a factor of 8% in the 2014 emission factors that compensate for planes not flying using the most direct route, i.e. flying around international airspace, stacking, etc.) and/or radiative forcing (a 90% increase in emissions, to include the influence of non-CO_2 climate change effects of aviation water vapour, contrails, NO_x, etc.). The 2014 DEFRA factors include the distance uplift factor. DEFRA provides emissions factors both with and without radiative forcing.

Spend-based method estimation

CO_2e emissions from business travel =

Sum across transport modes and/or vehicle types:

$\sum$ (amount spent on transportation by type ex.$) x

EEIO emission factor per unit economic value (kg CO_2e/$)

Additional detail, examples, and emission factor resources for applying business travel estimation methods are available in Chapter 6 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.7 EMPLOYEE COMMUTING

3.7.1 Category description

Employee commuting emissions include transportation of employees between their homes and their worksites. Sources of employee commuting emissions include employee travel by modes including cars, trains and buses.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

There are no petroleum industry-specific boundary considerations for this category. However, as illustrated in Table 12 in section 3.6.1, emissions from employee transportation often fall into several scopes and categories. Scope 3 Category 7 (employee commuting) includes emissions from employee transportation to and from work in vehicles not owned, controlled by or leased by the accounting company.

The majority of Category 7 emissions are typically captured in Category 11 (use of sold products) by companies that include emissions from transportation fuels such as gasoline and diesel fuel in their Category 11 emissions, and could therefore be double counted. Some companies choose not to include transportation fuel emissions in category 7 if these fuel specific emissions are already included in Category 11. For example, a company could demonstrate that emissions from fuels in Category 7 are less than the emissions estimated for those fuels in Category 11. Alternatively, if companies want to more fully understand emissions that result from Category 7 activities, or if segregating sold products emissions (Category 11) from Category 7 (employee commuting) emissions is deemed too onerous, companies typically choose to include fuel use emissions in both Category 11 and Category 7 regardless of any overlap.

3.7.2 Materiality considerations

Employee commuting emissions are a relatively minor source of scope 3 emissions across all oil and gas sectors.

3.7.3 Estimating emissions

Companies typically use one of the following methods to estimate emissions from business travel:

- **Distance-based method:** collect data from employees on commuting patterns, including distance and mode used, and apply emissions factors for the mode used.
- **Average-data method:** estimate emissions from employee commuting based on average data on commuting patterns.
- **Fuel-based method:** estimate the amount of fuel consumed during employee commuting and apply appropriate emissions factors for that fuel.

CASE STUDY

Screening-level assessment of employee commuting emissions

Shell estimated employee commuting emissions by assuming that each employee commutes 50 kilometres per day by car 220 days per year. They estimated that these activities result in less than 250,000 metric tonnes CO_2e per year. Based on this screening assessment, they determined that employee commuting is not a material Scope 3 category for their operations.

Further detail for the distanced-based and average-data methods is described below. Fuel use information is less likely to be available for employee commuting emissions estimations. Employee commuting activity data required for these estimations includes:

- daily commuting distance;
- mode of transport; and
- number of commuting days per week and weeks worked per year.

This data is typically obtained via employee surveys, based on company averages or estimates, or from secondary data sources such as national transportation departments, national statistics publications or industry associations.

Distance/average method estimation

CO_2e emissions from employee commuting =

Sum across transport modes:

$\sum$ (total employees x % using mode of transport) x
one way commuting distance (e.g. vehicle-km) x
2 x working days per year x
emission factor of transport mode
(e.g. kg CO_2e/vehicle-km)

Additional detail, examples, emission factor resources for applying employee commuting estimation methods are available in Chapter 7 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.8 UPSTREAM LEASED ASSETS

3.8.1 Category description

Category 8 (upstream leased assets) emissions include operation of assets leased by the company (lessee). Emissions sources could include leased office space, equipment and assets not included in scope 1 and scope 2.

Boundary considerations and relationship to scope 1 and 2 emission and other scope 3 categories

Leasing arrangements can involve crude oil production and processing equipment, service stations, bareboat charters, office buildings and other facilities. In some cases, companies have determined that the operation of leased assets is within their Scope 1 and 2 boundaries; in this case such emissions are typically not accounted for in scope 3. Some companies refer to Chapter 4 of the GHG Protocol Corporate Standard for additional details on accounting for emissions from leased assets.

Some petroleum companies are involved in retail operations (such as service stations) and may lease their retail space. Retail operations can potentially be classified into several scope 3 categories, as illustrated by Table 13 on page 41. Rather than split emissions from retail operations into multiple categories, some companies choose to group retail operations into one category (e.g. the category with the largest emissions based on company operations and boundaries) to provide stakeholders with an aggregate retail value.

3.8.2 Materiality considerations

Category 8 upstream leased assets are not a commonly reported emissions source, nor are they expected to be material. To understand Category 8 assets companies typically conduct screening level assessments for major leased assets such as LNG regasification facilities and/or leased office spaces, service stations and equipment that is not captured within their scope 1 and scope 2 boundaries. Some companies estimate leased emissions based on benchmark values including emissions per square foot, emissions per dollars spent and/or based on their own operational data for similar facilities.

Table 13 Scope and category classification of emissions for petroleum company retail operations

RETAIL OPERATIONS	SCOPE AND CATEGORY OF EMISSIONS
Within company boundaries	Scope 1 and 2
Assets leased by the company from others	Scope 3, Category 8 (upstream leased assets)
Assets owned by the company and leased to others	Scope 3, Category 13 (downstream leased assets)
Operating under a licence to sell or distribute company goods in return for payments, such as royalties for the use of trademarks and other services	Scope 3, Category 14 (franchises)
Other retail operations selling company products not otherwise captured in the Categories noted above	Scope 3, Category 9 (downstream transportation and distribution), which includes retail and storage
Branded sites that are not company-owned, leased or operated and do not sell or distribute the company's goods or services	Not included in Scope 3

3.8.3 Estimating emissions

Oil and gas companies often use one of the following methods to estimate emissions from Category 8 (upstream leased assets):

- **Average-data method:** estimate emissions from each leased asset, or groups of leased assets, based on average data, such as average emissions per asset type of floor space.
- **Asset-specific method:** collect site- or asset-specific scope 1 and 2 data from individual leased assets.
- **Lessor-specific method:** collect scope 1 and 2 emissions from lessor(s) and allocate emissions to the relevant leased asset(s).

Further detail for the average-data method is described below. Asset and lessor-specific information is less likely to be available for petroleum companies.

Average-data method

Some companies apply the average-data to estimate emissions from leased assets based on average statistics and secondary data, such as average emissions per asset type or floor space. Companies typically apply the average-data method when specific scope 1 and scope 2 data for leased assets are not available or applicable. Depending on the type of asset for which emissions are being estimated, companies typically determine:

- floor space for leased buildings;
- number of leased buildings, by building type; and
- number and type of leased assets other than leased buildings (e.g. company cars, trucks).

Companies often obtain data from internal real estate and asset management systems.

CO_2e emissions from leased buildings (based on floor space) =

Sum across building types:

$\sum$ (total floor space of building type (m^2) x

average emission factor for building type (kg CO_2e/m^2/year))

CO_2e emissions from leased assets =

Sum across asset types:

$\sum$ (number of assets x

average emission per asset type (kg CO_2e/asset type/year))

Additional detail, examples and emission factor resources for applying (upstream leased assets estimation methods are available in Chapter 8 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.9 DOWNSTREAM TRANSPORTATION AND DISTRIBUTION

3.9.1 Category description

Downstream transportation and distribution emissions include transportation and distribution of products sold by the company (e.g. crude oil, natural gas, natural gas liquids (NGLs), intermediates, and refined product) between the accounting company's operations and the end consumer, including interim transportation steps and retail and storage to the extent that the accounting company does not pay for such transportation.[6] Emissions include downstream product transportation that occurs after the company pays to produce and distribute its products.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

The Scope 3 GHG Protocol classifies outbound transportation purchased by the company as Category 4 (upstream transportation and distribution) versus Category 9 (downstream transportation and distribution) because they are purchased services. Table 11 in section 3.4.1 contains additional detail on classifying transportation distribution emissions in relation to other scope 3 categories. Companies typically include emissions from distribution activities conducted within their boundaries in scope 1 and 2.

The majority of Category 9 (downstream transportation and distribution) emissions are typically captured in Category 11 (use of sold products) by companies that include emissions from transportation fuels such as gasoline, diesel and jet fuel in their Category 11 emissions, and could therefore be double counted. Some companies choose not to include transportation fuel emissions in Category 9 if these fuel combustion emissions are already included in Category 11. Alternatively, if companies want to more fully understand emissions that result from Category 9 activities, or if segregating sold products emissions (Category 11) from Category 9 (downstream transportation and distribution) emissions is deemed too onerous, companies may choose to include fuel use emissions in both Category 11 and Category 9.

3.9.2 Materiality considerations

Downstream transportation and distribution does not appear to be a material emission category for the oil and gas sector, with the exception of companies that do not pay for their product distribution. Companies that do not pay for their product distribution often conduct a screening assessment to determine whether their downstream distribution is material.

3.9.3 Estimating emissions

Estimating emissions from downstream transportation should follow the methods described for Category 4 (upstream transportation and distribution) described in section 3.4.3. The major difference between estimating scope 3 upstream and downstream emissions of transportation is likely to be the availability of the activity data. Transportation data is typically easier to obtain from suppliers from whom they purchase distribution services than from downstream customers and transportation companies; thus, companies are more likely to apply the average-data method.

CASE STUDY

Estimating emissions from leased LNG terminals based on capacity rights

Shell has capacity rights at LNG terminals that they classify as leased assets. They obtain GHG emissions from one of these facilities and use these emissions to estimate emissions per volume processed at an LNG facility. This intensity benchmark is then used to estimate the GHG emissions from Shell's share of production at other facilities by multiplying by the appropriate factor to reflect the volume of LNG supplied by Shell to each of the leased facilities.

[6] Note that emissions from downstream leased assets paid for by the company are typically included in Category 13.

Additional detail, examples and emission factor resources for applying downstream transportation and distribution estimation methods are available in Chapter 9 of the GHG Protocol guidance (WRI/WBCSD, 2013).

3.10 PROCESSING OF SOLD PRODUCTS

3.10.1 Category description

Processing of sold product emissions includes processing of intermediate products that are sold by companies (e.g. E&P companies and refiners). Intermediate products are those that require further processing, transformation or inclusion in another product before use and therefore result in emissions from processing subsequent to sale by the accounting company and *before use by the end consumer*. For example, a refiners processing of crude oil would be a Category 10 (processing of sold products) activity for an E&P company. Depending on a company's scope 1 and 2 boundaries, sources of processing emissions from sold products may include crude oil refining, natural gas processing (to separate NGLs) and petrochemical product manufacture.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

As discussed above and in section 2.4, emissions from the processing of sold products depend on a company's operations and location in the value chain. Table 14 illustrates processing emissions that different types of companies are likely to include in Category 10. For example, refiners, natural gas processors, and integrated oil and gas companies that sell petroleum products that are subject to further processing (e.g. natural gas and petroleum products inputs for plastic manufacture) should consider Category 10 emissions.

Most Category 10 activities will include fuel combustion emissions, potentially double counting with Category 11 (use of sold products). Take for example an E&P company that sells crude to a refinery for further processing: in this case, the E&P company's Category 10 emissions would include any fuel or electricity used by the refinery to process that crude. However, that same fuel used by the refinery could be fuel that the E&P company has included in Category 11 (use of sold products). To address this potential double counting, companies have the option not to include fuel emissions in Category 10 if these fuel specific emissions are already included in Category 11, as illustrated in section 2.3.3. However, it may be difficult to determine the extent to which Category 10 emissions are already presented in Category 11. For example, a company may find it difficult to determine the proportion of processing emissions that result from the combustion of petroleum products versus emissions from other sources, such as coal-fired electricity generation or process emissions (particularly from secondary data sources). Therefore, some companies may choose to include fuel use emissions in both Category 11 and Category 10, regardless of any overlap, if segregating sold products emissions (Category 11) from Category 10 emissions is deemed too onerous.

Table 14 Emissions included in category 10 based on company type and petroleum processing stage

COMPANY TYPE	EXTRACTION AND PRODUCTION	PETROLEUM PRODUCT REFINING	SOLD PRODUCTS PROCESSED INTO OTHER PRODUCTS	PRODUCT USE AND DISPOSAL
Integrated oil and gas company	Not included in Category 10	Include if sold products refined outside of company boundaries	√ Category 10	Not included in Category 10
E&P company	Not included in Category 10	√ Category 10	√ Category 10	Not included in Category 10
Refining company/ natural gas processor	Not included in Category 10	√ Category 10	√ Category 10	Not included in Category 10
Petrochemical company	Not included in Category 10	Not included in Category 10	√ Category 10	Not included in Category 10

3.10.2 Materiality considerations

Category 10 (processing of sold products) can potentially represent a material proportion of scope 3 emissions depending on a company's location in the value chain and the type and amount of sold product it processes. Emissions from the processing of sold products are typically more material to companies upstream in the value chain. For example, companies that provide input materials to refineries typically classify refinery emissions as Category 10.

3.10.3 Estimating emissions

Oil and gas companies often use one of the following methods to estimate emissions from processing of sold products:

- **Average-data method:** estimate emissions for processing of sold intermediate products based on average secondary data, such as average emissions per process or product.
- **Site-specific method:** estimate the specific third-party processing emissions based on the amount of fuel and electricity used and the amount of waste generated.

The average-data method is described below. Customer site-specific processing information is less likely to be available for petroleum companies.

Average-data method

In this method, companies collect data on, or estimate, the amount of sold products that are further processed and the types of products into which they are processed (e.g. refining crude oil into gasoline) and apply relevant industry average emissions factors for processing sold products into final products to determine emissions.

CO_2e emissions from processing of sold intermediate products =

Sum across intermediate products:

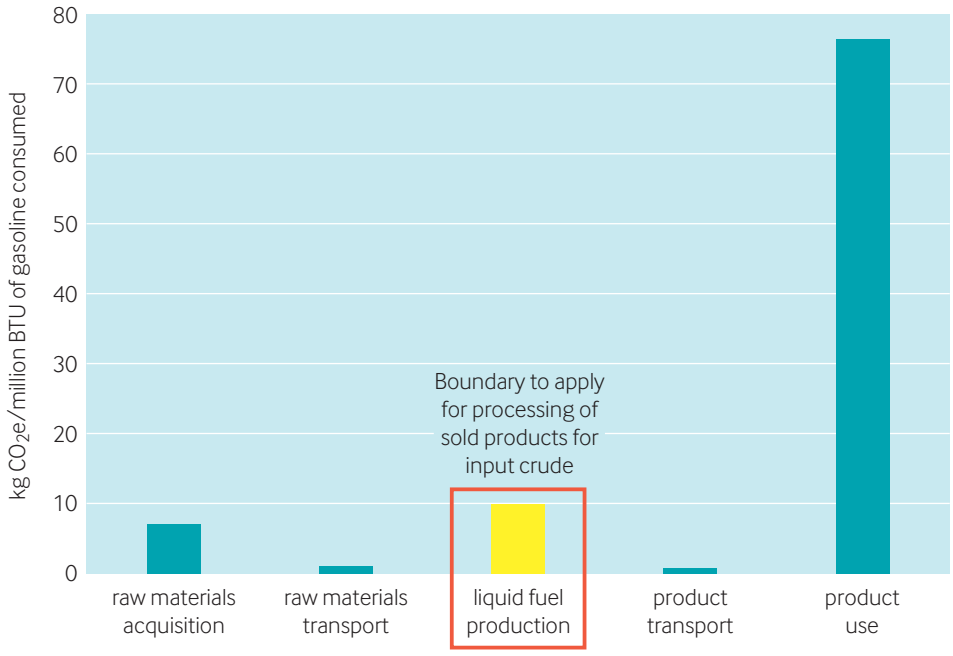
∑ (mass or volume of sold intermediate products (kg or BOE) x

mass or volume of final product per mass or volume of intermediate products x

emission factor of processing final products (kg CO_2e/kg or BOE of final product) x Allocation factor*)

* If the final product has multiple intermediate product inputs, companies often allocate processing emissions to the intermediate product as illustrated in Example 4.1(b) (by mass) and Example 4.2 (by energy). Chapter 8 of the GHG Protocol Scope 3 Standard presents additional guidance on allocation.

Figure 6 Select appropriate boundary for GHG emission factors associated with product processing



Companies should aim to confirm that the boundaries for emission factors that they apply for Category 10 (processing of sold products) emissions include only the life-cycle stages associated with processing the intermediate product into the final product. For example, if an E&P company estimates Category 10 emissions associated with refining, the companies often apply the gate-to-gate emissions factor for the refinery rather than the cradle-to-gate or cradle-to-grave emission factor. For example, Figure 6 illustrates the GHG emissions associated with different life-cycle phases of gasoline (NETL, 2009). An E&P company would apply the emission factor associated with the 'liquid fuel production' phase to calculate its Category 10 (processing of sold products) emissions.

The following examples provide illustrations of the average-data estimation method for the following scenarios:

- **Example 4.1:** estimating emissions associated with crude oil processing into (a) refinery products and (b) subsequent processing into plastic precursors and polymers applying mass-based allocation.
- **Example 4.2:** estimating processing emissions associated with plastic emissions applying embodied energy allocation.

EXAMPLE 4.1 Estimating emissions associated with crude oil processing

Example 4.1(a) Estimating crude oil processing emissions from refining

An E&P company produces 100 million barrels (bbl) of crude oil. They estimate the refinery products produced from the 100 million barrels of crude oil based on international statistics on refinery output, as illustrated in Box 2 on page 49. They multiply the amount of refinery products produced by the product-specific refining emissions factor to determine their refinery processing emissions. All processing emissions are allocated to the crude oil:

Final product produced from crude	Estimated amount of product produced (million bbl)	kg CO_2e/bbl of product refined	Refinery processing emissions (million metric tonnes CO_2e)
Gasoline	45	48	2.16
Diesel	23	53	1.20
Kerosene/jet fuel	9	32	0.29
Residual fuel oil	4	37	0.13
Coke	5	44	0.21
Light ends	10	30	0.29
Heavy ends	4	69	0.30
			Total: 4.58

Note: activity data are illustrative only, and do not refer to actual data.

continued ...

EXAMPLE 4.1 Estimating emissions associated with crude oil processing (continued)

Example 4.1(b) Estimating process emissions beyond the refinery: mass based allocation

Some of the refinery products produced by the E&P company, such as light ends (e.g, naphtha) are further processed into other products such as plastic precursors and polymers. Although the eventual use of intermediate products may not be known, this example illustrates how the E&P company in the example above could conduct a screening-level estimate of product processing emissions by assuming that the light ends are converted into ethylene and then into high density polyethylene (HDPE) by applying the following formula and the following steps:

$$\text{Process emissions} = \text{total intermediate product} \times \frac{\text{1 kg final product}}{\text{amount of intermediate in final product}}$$

$$\times \text{ Processing EF } \left(\frac{\text{kg } CO_2e}{\text{final product}} \right) \times \text{ allocation factor}$$

1. **Estimate the total intermediate product:** in this scenario, naphtha is the intermediate product for which the company is estimating processing emissions (the processing emissions associated with converting crude oil into naphtha are estimated in Example 4.1(a) on page 45). As illustrated in example 4.1(a), the E&P company produces approximately 10 million barrels of naphtha, or 1.2 million metric tonnes, from the 100 million barrels of crude.
2. **Estimate the total amount of final products:** the company assumes that all of their light ends are processed into ethylene and all of the ethylene is processed in to HDPE. They determine the mass of ethylene and HDPE per input mass of naphtha and multiply by the input naphtha to calculate the total amount of ethylene and HDPE produced.
3. **Obtain the processing emission factor:** in this example the processing emissions for the ethylene and those for the subsequent HDPE production are estimated separately. The emissions factors exclude any product emissions (e.g. E&P and refining) that occur prior to, or after, the ethylene and HDPE processing stages (as illustrated in Figure 6).
4. **Allocate processing emissions to the naphtha:** ethylene and HDPE processing both include natural gas feedstocks in addition to the naphtha. Thus, some of the processing emissions should be allocated to the natural gas. To estimate the processing emissions allocated to the naphtha, the company applies an allocation factor. Because the company allocates emissions based on mass (which is a common method recommended by GHG Protocol Scope 3 guidance), the process emissions are typically estimated by multiplying the amount of company product by the associated final product emissions factor. In this case, the percent of intermediate product per final product cancels out of the equation and is not required. (Note that emissions should only be allocated to the intermediate products that are further processed. For example, if a company was estimating the processing emissions associated with natural gas, they would consider only the natural gas used as feedstock, and would exclude any natural gas used as fuel).

Example 4.1 variables		
Amount of company product	1.2 million metric tonnes	Based on estimated amount of light ends and density of naphtha
Input kg naphtha/kg ethylene	0.88	Based on Feedstock energy input
CO_2e/kg ethylene process	0.92	Ethylene processing
Input kg naphtha/kg HDPE	0.88	Based on feedstock energy input
CO_2e/kg HDPE	0.31	HDPE processing

continued ...

Example 4.1 Estimating emissions associated with crude oil processing (continued)

Emissions from naphtha into ethylene and HDPE =

$$1.2 \times 10^9 \text{ kg naphtha} \times \frac{1\text{kg ethylene}}{0.88 \text{ kg input naphtha}} \times \frac{0.92 \text{ kg } CO_2e}{\text{kg ethylene processing}} \times \frac{0.88 \text{ kg input naptha}}{1 \text{ kg ethylene}} +$$

$$1.2 \times 10^9 \text{ kg naphtha} \times \frac{1\text{kg HDPE}}{0.88 \text{ kg input naphtha}} \times \frac{0.31 \text{ kg } CO_2e}{\text{kg HDPE processing}} \times \frac{0.88 \text{ kg input naptha}}{1 \text{ kg HDPE}} =$$

1.5 million metric tonnes CO_2e

EXAMPLE 4.2 Estimating process beyond the refinery: embodied energy approach

A natural gas producer estimates that its feedstock products are used to produce one million metric tonnes of PET resin. The company obtains the emission factor associated with processing PET from secondary data and allocates these emissions to its natural gas intermediate product based on the relative percent of embodied energy in the polymer:

The company estimates its Category 10 (processing of sold products) emissions based on the following equation:

1 million metric tonnes PET x 0.425 metric tonnes process CO_2e per metric tonne PET x
9% relative percent of embodied energy in polymer =
37,400 metric tonnes CO_2e

Emissions factors

Table 15 on page 48 provides resources that are typically used by companies to obtain data on processing emissions for key petroleum industry products, in addition to process-related third-party datasets (e.g. Ecoinvent, USLCI and ILCD).

As well as using the references listed in Table 15, some companies obtain data on supplier emissions from CDP questionnaire responses (CDP, 2013). In addition, some companies develop emissions intensity factors for different operations. For example, Shell publishes emission factors for upstream operations, oil sands, chemicals and refineries on the Greenhouse Gas Emissions section of their Climate Change website (Shell, 2013).

Table 15 Emission factor references for processing of intermediate products relevant to petroleum companies

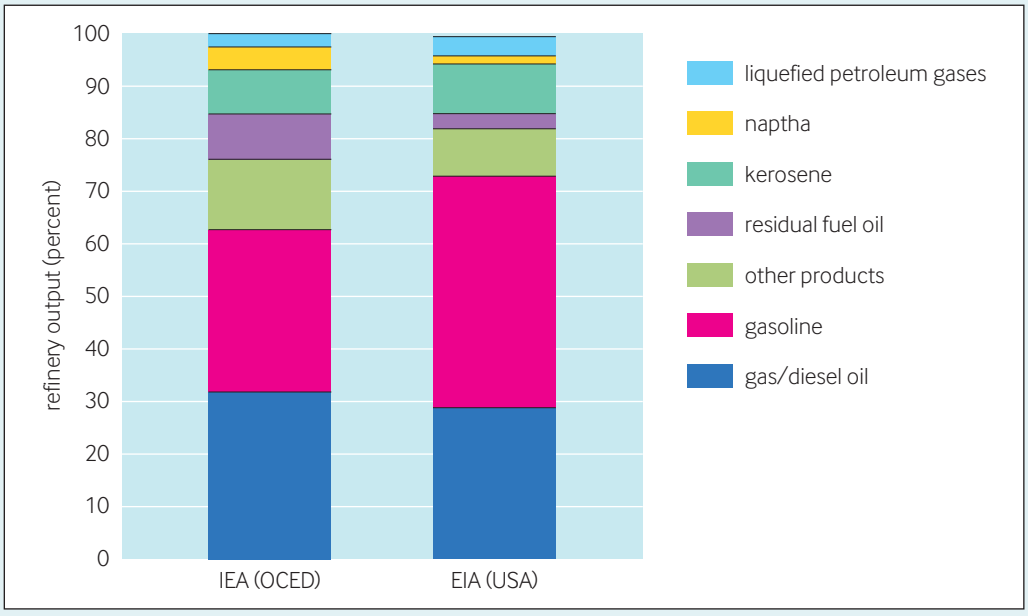
REFERENCE	FACTORS INCLUDED	LOCATION
Abella, J. P. and Bergerson, J. A. (2012). *Model to Investigate Energy and Greenhouse Gas Emissions Implications of Refining Petroleum: Impacts of Crude Quality and Refinery Configuration.* Geography: North America	Conventional oil refining; Dilbit/Syndilbit Oil Refining	http://pubs.acs.org/doi/abs/10.1021/es3018682
Chehovits, J. and Galehouse, G. (2010). *Energy Usage and Greenhouse Gas Emissions of Pavement Preservation Processes for Asphalt Concrete Pavements.* Geography: United States	Emissions from asphalt production.	https://trid.trb.org/view.aspx?id=919015
Edwards, R Larive, J., Rickeard, D. and Weindorf, W. (2014). *Well-To-Tank Report Version 4.a. JEC Well-To-Wheels Analysis.* Geography: Europe	Emission factors for refining based on a marginal methodology.	http://iet.jrc.ec.europa.eu/about-jec/sites/iet.jrc.ec.europa.eu.about-jec/files/documents/report_2014/wtt_report_v4a.pdf
EPA (2000). *Hot Mix Asphalt Plants: Emission Assessment Report.* Geography: United States	Emissions from hot mix asphalt processing plants	www.epa.gov/ttnchie1/ap42/ch11/related/ea-report.pdf
Franklin Associates (2011). *Cradle-to-Gate Life Cycle Inventory of Nine Plastics Resins and Four Polyurethane Precursors.* Geography: United States	Emissions from the processing of plastics (HDPE, LDPE, LLDPE, PP, PET, GPPS, HIPS, ABS, Polyurethane, MDI, TDI)	http://plastics.americanchemistry.com/LifeCycle-Inventory-of-9-Plastics-Resins-and-4-Polyurethane-Precursors-Rpt-Only
Franklin Associates (2011). *Life Cycle Inventory of Plastic Fabrication Processes: Injection Molding and Thermoforming.* Geography: United States	Emissions from the processing of plastics.	http://plastics.americanchemistry.com/Education-Resources/Publications/LCI-of-Plastic-Fabrication-Processes-Injection-Molding-and-Thermoforming.pdf
International Council of Chemical Associations (ICCA) (2009). *Innovations for Greenhouse Gas Reductions.* Geography: Global	Emissions from the processing of chemicals and lubricants.	https://www.americanchemistry.com/Policy/Energy/Climate-Study/Innovations-for-Greenhouse-Gas-Reductions.pdf
National Asphalt Pavement Association (NAPA) (2012). Greenhouse Gas Calculator Geography: United States	Emissions from the processing of Asphalt pavement manufacturing.	www.asphaltpavement.org/index.php?option=com_content&task=view&id=545&Itemid=1143
PlasticsEurope (2011, April). Eco-profiles and Environmental Product Declarations. Version 2.0. Geography: Europe	Emissions from processing of high volume bulk polymers, widely used engineering plastics, and standard plastics (pentane, xylenes, toluene, benzene, ethylene, propylene, butadiene, POM, natural gas, ammonia, hydrogen, acetone, phenol, styrene, HDPE, LDPE, PP, PVC, terephthalic acid, PMMA, PET, ABS, BPA, epoxy, formaldehyde, polyols).	www.plasticseurope.org/documents/document/20110421141821-plasticseurope_eco-profile_methodology_version2-0_2011-04.pdf

Box 2 Estimating the type and amount of final products

Activity data associated with the types and amount of final products produced can be important in estimating the emissions from Categories 10 (processing of sold products), Category 11 (use of sold products) and Category 12 (end-of-life treatment of sold products). For example, processing and combustion emissions are product-specific. However, the eventual end use of sold products may be unknown for many petroleum companies. The GHG Protocol Scope 3 Standard implies that when it is possible to reasonably estimate the downstream emissions associated with processing intermediate products, they should be estimated. In certain cases, the eventual end use of sold intermediate products may be unknown, and companies may be unable to reasonably estimate the downstream emissions associated with processing, end uses or waste of the intermediate product. In such cases, companies can disclose and justify the exclusion of downstream emissions in any account (WRI/WBCSD, 2011).

In some cases companies know the final products produced; in other cases estimation is required. E&P companies may estimate final products based on total crude and natural gas produced. Refiners may have actual information on final products produced, or may estimate from refinery throughput. As described in Box 3 (page 51), IO&G companies may have actual information on final products produced, or may estimate from refinery throughput and/or production. When estimation is required, companies can apply national or international ratios to estimate the final products per BOE or gas produced in each of the cases. For example, IEA (2016) produces monthly oil data and survey information that includes the refinery gross output in OECD regions. Likewise, the US Energy Information Administration (EIA, 2016) provides US and regional breakouts of refinery product yield by product. The chart below illustrates refinery outputs by percentage for the OECD and USA for 2013.

Refinery outputs by percentage for the OECD and USA for 2013



3.11 USE OF SOLD PRODUCTS

3.11.1 Category description

Use of sold product emissions in the oil and gas sector includes the direct end-use phase emissions of final products such as motor fuels and natural gas. This includes the end-use phase emissions of sold intermediate products such as crude oil. Category 11 includes the total expected lifetime use emissions for products sold during the accounting year, independent of when the actual use occurs.

Relationship to Scope 1 and 2 emissions and other scope 3 categories

Emissions from the use of sold products from oil and gas companies are produced from the direct use-phase of fuels, or GHGs and products that contain or form GHGs (e.g. fertilizers). Petroleum companies are unique in that the use of fuel products they produce can contribute to emissions in almost all other scope 3 categories. For example, diesel fuel produced by a petroleum company could be used to fuel company scope 3 distribution activities (accounted for in Categories 4 and 9) or business travel (Category 6). Likewise, natural gas may be used to produce energy or heat for producing input materials or for processing sold products (Categories 1 and 10).

Companies often elect not to include fuel emissions in relevant categories (i.e. 4, 6) if these fuel-specific emissions are already included in Category 11. To demonstrate this, companies could determine that the sum of any other fuel combustion emissions that would be captured in other scope 3 categories are less than the total fuel-specific emissions reported in Category 11. For example, if a company estimates that the fuel-specific emissions from a scope 3 category, e.g. jet fuel use in Category 6 (business travel), are less than the emissions estimated for jet fuel in Category 11, companies may exclude Category 6 (business travel) emissions and document the fact that these emissions are included in Category 11.

Alternatively, if companies want to more fully understand emissions that result from fuel use activities (such as those in Categories 4 or 6), or if segregating sold products emissions (Category 11) from other scope 3 activities is deemed too onerous, companies typically choose to include fuel use emissions in both Category 11 and other relevant categories (i.e. 1, 10, etc.) and note that these emissions may be double counted in Category 11. For example, some gas companies state that they include emissions from sold products in Category 11 while their emissions from gas combustion may also appear in other categories that potentially include natural gas combustion as an emissions source, such as Category 1 (purchased goods and services) and Category 10 (processing of sold products) in which natural gas may be used in product manufacturing or processing.

3.11.2 Materiality considerations

Use of sold products is material to the majority of oil and gas companies, with the exception of petrochemical companies that do not produce fuels or other products such as fertilizers that produce GHG emissions when they are used by customers. For the majority of companies, these emissions will likely be larger than scope 1 and scope 2 emissions combined. Companies that produce or refine significant quantities of crude oil, natural gas and NGLs as fuels should assess materiality for this category. The use of sold products is typically the most significant contributor to emissions for fuel-producing companies and can account for more than 80% of total scope 3 emissions. Companies typically describe their strategy for accounting for potential double counting of fuel emissions between scope 3 categories.

3.11.3 Estimating emissions

Estimating use-phase emissions first requires companies to determine what constitutes the quantity of products sold. For E&P companies, products sold include the total crude and natural gas produced; for refiners and retailers, products sold include the refinery and retail products sold, respectively. However, what constitutes the products sold can be more difficult to identify for IO&G companies that sell products at several points throughout their operations. Box 3 describes the net volume accounting method for determining what constitutes sold products for oil and gas companies.

Companies typically then apply one of two approaches to estimate emissions from sold products. One approach requires knowing the types and amounts of final products, and the other approach, which is based on carbon content, does not. To use the first approach, some companies identify the final products produced from their product sold. Companies such as retailers and

Box 3 Defining what constitutes sold products for integrated oil and gas companies

The amount of products sold is often the key component of an oil and gas company's scope 3 inventory. It is fundamental to being able to estimate Category 11 (use of sold products) emissions and also relevant for companies endeavouring to calculate emissions in Categories 10 (processing of sold products) and 12 (end-of-life treatment of sold products). In some cases, such as for integrated oil and gas (IO&G) companies, companies may sell products at several points throughout their operations. The potential complexities of company operations can complicate defining and quantifying what constitutes 'sold products'. As an example, the illustration on the right presents a simplified illustration of four petroleum companies with different operations along the product value chain.

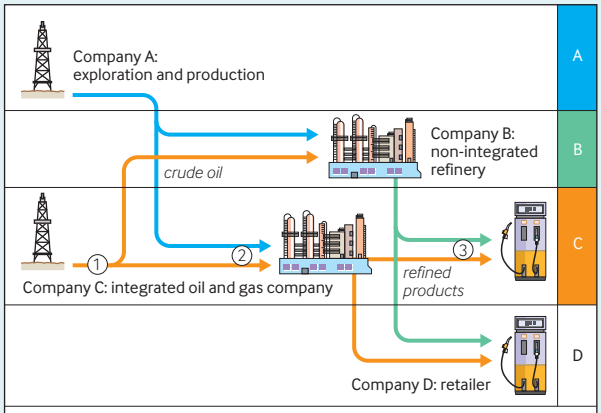
To avoid onerous accounting for IO&G companies, such as accounting for the movement of each molecule (e.g. specifying discrete inputs and outputs, such as the specific amount of Company C crude oil used in Company C refineries) companies can use net volume accounting. In net volume accounting companies identify that point in the value chain where the largest total amount of potential sold products is transferred:

1. crude produced;
2. refinery throughput (refinery throughput is used to enable equivalent comparison between companies that don't have readily available information on refinery output); or
3. retail and commercial (marketing) operations (i.e. sales to end users). When sales data to end users are not readily available in a consolidated form, some companies choose instead to use production or refinery data.

These three points are illustrated in the figure on the right. Fuels used on site (such as refinery fuels) or in self-fuelled fleets captured in Scope 1 should be excluded from the determination of the largest amount of potential sold products when practical to do so.

As illustrated below, if the amount of hydrocarbons extracted is greater than the amount processed at refineries downstream and sold via a company's retail operations, accounting for the use of products at the point of extraction captures the emissions downstream of the extraction point.

See Box 2 (page 49) for details of how the amount of final products can be estimated from crude produced and refinery throughput.



Company A: an E&P company that produces crude oil and sells it to Refinery B and IO&G Company C.

Company B: a non-integrated refinery that purchases crude oil from E&P Company A and IO&G Company C.

Company C: an IO&G company that produces crude oil and has refinery as well as retail and commercial (marketing) operations. In addition to producing its own crude oil, IO&G Company C purchases crude oil from E&P Company A. IO&G Company C sells retail and commercial products produced by its own refining operations as well as some produced by refinery Company B. IO&G Company C also sells refinery products to retailer Company D.

Company D: a retail operation that purchases products from refinery Company B and IO&C Company C.

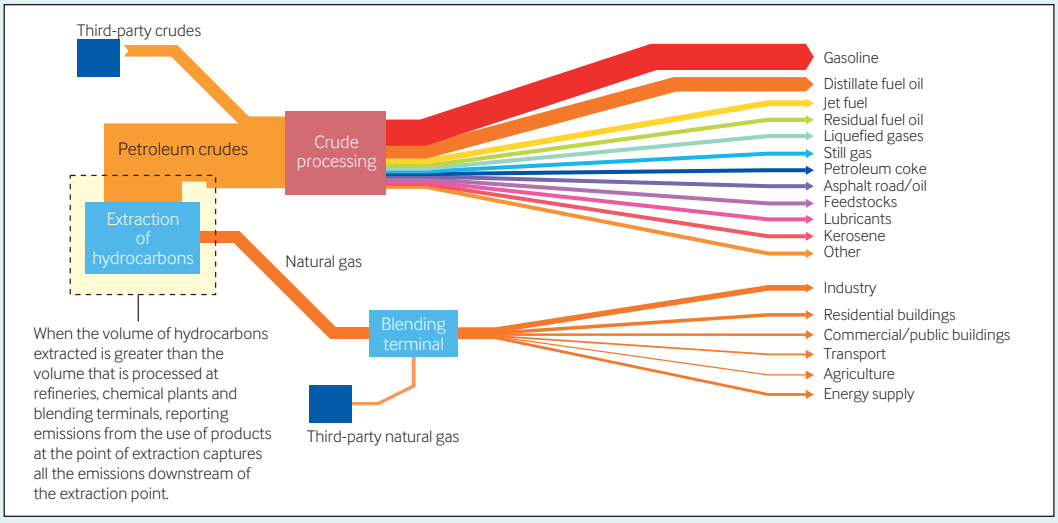


Illustration of how total sold products can potentially be captured at the point of extraction

petrochemical companies are often able to directly determine the amount and types of products that they should include in the Category 11 estimations based on their operations and sales. Similarly, some refiners know the quantity and type of products sold. In certain cases, for some E&P companies, the eventual use of sold products may be unknown, and companies may be able to estimate their final products produced based on crude produced or refinery throughput, as illustrated in Box 1.

For both the final product and the carbon content approach for direct emissions from fuel products, no use-phase emissions should be estimated for a feedstock if is not combusted during the use phase—for example, if it is used to produce plastics, lubricants or asphalt. Only combustion emissions, not the embodied emissions associated with the fuel extraction, production and transportation should be included.

IO&G companies whose accounting basis may change when considering the approach shown in Box 3 can consider several options. To promote transparency and to allow for year-on-year comparisons for IO&G companies who may have used a different product/point in the value-chain in previous accounting years, some companies also include emissions from any or all of the points. For example, if a company previously based their used product emissions on refinery products, but in using the Box 3 approach recognize that their retail value is larger, they typically choose to account for sold product emissions based on both sales to end users and on refinery production.

Estimation method for direct use-phase emissions from fuels based on final products

To estimate emissions from fuels based on the final products, multiply the quantities of fuels by the combustion emissions factors for the fuels.

Direct use phase emissions from combusted fuels =

Sum across fuels:

$\sum$ (total quantity of fuel sold x

combustion emission factor for fuel)

Activity data needed:

- Total quantity of fuels sold (see Box 3 for details on defining what constitutes sold products for IO&G companies). Companies typically derive fuel quantities sold based on sales records or estimated from crude produced or refinery throughput as described in Box 3.

Emissions factor needed:

- Combustion emission factor of fuels.

Estimation method for direct use-phase emissions from fuels based on carbon content

To estimate emissions from fuels based on the carbon content, determine the carbon content of the crude oil and natural gas that is produced, subtract the carbon accounted for in scope 1 emissions and non-combusted products, and convert to CO_2.

Direct use phase emissions from combusted fuels =

CO_2 = (total crude oil –

amount of crude used to produce non-fuel products –

amount of crude accounted for in the company's Scope 1 emissions) x

carbon content/$unit_{crude}$ x 44/12

See the following pages for examples of estimating the use of sold products based on estimated final products in (a) the refinery (Example 5.1) and (b) exploration and production (Example 5.2), and (c) based on carbon content (Example 5.3).

EXAMPLE 5.1 Estimating use of sold products based on estimated final products: refinery

A refinery company processes one hundred million metric tonnes of crude oil at refineries across the USA. Because the company cannot easily obtain the specific amounts and types of products they produce, the company estimates their total quantity of products produced based on regional refinery yield statistics. They estimate the percentage of each product sold (i.e. not used by the company and included in their scope 1 emissions) and the percentage combusted, and multiply these values by the product produced to estimate the total products sold as fuel. They multiply each fuel sold by the associated emission factor to determine the emissions from sold products.

Emissions from combusted product sold =

Amount of crude x % of product produced from crude x % of product sold x % of product combusted

Product	% product produced from crude	% product sold	% product combusted	Total combusted product sold (million metric tonnes)	Emission factor (metric tonne CO_2e/metric tonne)	Emissions from sold products (million metric tonne CO_2e)
Gas/diesel Oil	33%	100%	100%	33	3.19	105
Gasoline	31%	100%	100%	31	3.07	95
Kerosene	9%	100%	100%	9	3.15	28
Naphtha	4%	100%	0%	-	NA	-
LPGs	2%	100%	100%	2	2.98	6
RFO	9%	90%	100%	8.1	3.13	25
Lubricants/waxes	1%	100%	0%	-	NA	-
Asphalt and road oil	2%	100%	0%	-	NA	-
Petroleum coke	5%	100%	100%	5	3.17	10
Still gas	4%	0%	100%	-	NA	-
			Totals:	88.1		269

Note: the activity data and emissions factors are illustrative only and do not refer to actual data.

EXAMPLE 5.2 Estimating use of sold products based on estimated final products: exploration and production

An exploration and production company produces crude oil, natural gas and natural gas liquids. *They estimate the products produced from their crude oil as shown below based on international statistics (see Box 2).* They assume that all of their natural gas and natural gas liquids are combusted. They multiply each fuel sold by the associated emission factor to determine the emissions from sold products.

Product	Amount	Emission factor (kg CO_2e per bbl or ft^3)	Emissions from sold products (million metric tonne CO_2e)
Crude oil	1 million bbl →		
Gasoline	0.5 million bbl	370	0.19
Diesel	0.17 million bbl	430	0.07
Kerosene jet fuel	0.1 million bbl	410	0.04
Other oil	0.1 million bbl	445	0.04
Other light ends	0.08 million bbl	357	0.03
Non-combusted	0.05 million bbl	N/A	0
Natural gas liquid	0.2 million bbl	235	0.05
Natural gas	100 million cubic feet	0.054	0.01
			Total: 0.43

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

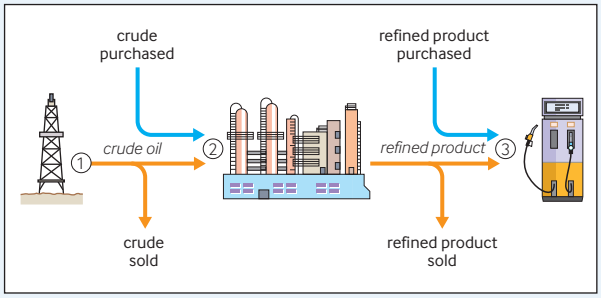
EXAMPLE 5.3 Estimating use of sold products based on carbon content

The IO&G company compares the volume of products sold at the following three points:

1. Crude produced: 100 million barrels
2. Refinery throughput: 90 million barrels
3. Retail and commercial sales to end users: 95 million barrels

The company does not need to estimate the specific amounts of crude or refined products purchased from and sold to other companies (e.g. the amounts associated with the blue and red arrows.) Instead some companies determine the net volume at points 1, 2 and 3. The company determines that the amount of crude produced (point 1) has the largest net volume (100 million barrels). The company uses this value as the basis for its 'amount of sold products'.

Eight percent of the company's crude is used to produce non-combusted products, and 5% of the crude is used to produce products used by the company or otherwise accounted for in their scope 1 emissions. They estimate their use of sold products applying the following equation:



CO_2 =

(100 million barrels crude oil − (0.13 x 100 million barrels)) x

0.11 metric tonne C/barrel x 44/12 =

35 million metric tonne CO_2

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

Emissions factors for fuel combustion

Table 16 provides references for factors that companies typically apply to estimate the fuel combustion emissions. No specific source for combustion factors is recommended, as companies may be required to use factors specific to a regulatory reporting requirement, such as those specified for the US EPA's Greenhouse Gas Reporting Rule (40 CFR Part 98) (EPA, 2009).

Estimation method for direct use-phase emissions from GHGs and products that contain or form GHGs that are emitted during use

Activity data needed:

- total quantities of products sold;
- quantities of GHG contained per product; and
- percentage of GHGs released through the lifetime of the product (if the percent released is unknown then 100% should be assumed).

Emissions factors needed:

- Global warming potentials (GWPs) of the GHGs contained in the product (e.g., 25 kg CO_2e/kg GHG).

Emissions from GHGs and products that contain or form GHG during use =

Sum across GHGs released in a product for all GHG-containing/forming products:

$$\sum_{\text{GHG per product}} (\text{amount of product sold} \times \%\ \text{of GHG released during the product lifetime} \times \text{GWP of GHG})$$

Table 16 Emission factor references for fuel combustion

REFERENCE	FACTORS INCLUDED	LOCATION
API *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*	CO_2, CH_4 and N_2O combustion emissions factors for common and specialized fuel types; densities, higher heating values and carbon contents for various fuels	www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf
EIA, CO_2 Emissions From Fuel Combustion Highlights, 2015	Implied carbon emission factors from electricity generation (CO_2/kWh) for selected products	www.iea.org/publications/freepublications/publication/co2-emissions-from-fuel-combustion-highlights-2015.html
Greenhouse Gas Protocol: Emissions Factors from Cross-Sector Tools	Heating value, fuel density, CO_2, CH_4 and N_2O combustion emission factors for fuel consumption stationary and transport fuel per energy, mass and volume	www.ghgprotocol.org/calculation-tools/all-tools
The Climate Registry: Default Emission Factors	Heat content, carbon content, CO_2, CH_4 and N_2O emission factors from fossil fuel and biomass combustion per unit energy, mass or volume	www.theclimateregistry.org/resources/protocols/general-reporting-protocol/
US EPA, Center for Corporate Climate Leadership	Emissions Factors for Greenhouse Gas Inventories from the EPA's Greenhouse Gas Reporting Program	www.epa.gov/climateleadership/inventory/ghg-emissions.html

3.12 END-OF-LIFE TREATMENT OF SOLD PRODUCTS

3.12.1 Category description

End-of-life treatment of sold products includes waste disposal and treatment of products sold by the company at the end of their life. Emissions may result from landfill disposal, recovery for recycling (such as collection and transportation to the recycling facility), and incineration of petroleum-based products such as lubricants and plastics. This category includes the expected end-of-life emissions from products sold during the accounting year, independent of the year in which they are actually disposed of.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Category 12 (end-of-life treatment of sold products) does not include emissions from products that are consumed during use, such as fuels; these emissions are captured in Category 11 (use of sold products). Thus, companies that sell products that are not consumed during use, such as lubricants or plastics, will have product end-of-life emissions to include in this category. If all of a company's products are sold as fuel (and captured in Category 11), emissions in Category 12 will be zero.

3.12.2 Materiality considerations

This category is typically more material to companies that produce large quantities of products such as lubricants or plastics that are disposed of via incineration. As noted above, the GHG Protocol Scope 3 Standard directs companies to consider estimating emissions for this category if they can reasonably estimate the downstream emissions associated with end use.

Some companies that produce non-fuel products will estimate emissions in this category based on stakeholder/customer interest and regulatory incentives focused on disposal of non-fuel products, such as chemicals, lubricants and solvents. This category will also be material for companies that sell products in regions that require the reuse or recycling of rigid plastic packaging containers and motor oil due to the potential significant disposal-related environmental impacts, including high levels of GHG emissions associated with product incineration.

3.12.3 Estimating emissions

Section 3.5.3 describes the estimation methods for end-of-life treatment methods (e.g. landfilling, incineration, and recycling) that apply to both Category 5 (waste generated in operations) and Category 12 (end-of-life treatment of sold products). Instead of collecting data on the total mass of waste generated in operations, companies should collect or estimate data on the total mass of sold products (and packaging) from the point of sale by the accounting company through the end-of-life use by consumers.

The major difference between estimating emissions from waste generated in operations (Category 5) and end-of-life treatment of sold products is likely to be the availability and quality of the waste activity data. Where companies have the specific waste types and waste treatment data from their own operations, this information is likely to be more difficult to obtain for sold products, as companies typically do not know the waste-disposal behaviour of consumers and retailers.

Some companies estimate:

- the total mass of sold products and packing from the point of sale by the accounting company to the end-of-life after consumer use (e.g. packaging used to transport products through to the point of retail and any packaging that is disposed of prior to the end-of-life of the final product); and
- the proportion of this waste being treated by different methods (e.g. percent landfilled, incinerated, recycled).

Waste-type specific method

CO_2e emissions from end-of-life treatment of sold products =

Sum across waste treatment methods:

$\sum$ (total mass of sold products and packaging from point of sale to end-of-life after consumer use (kg) x

% of total waste treated by waste treatment method x emission factor of waste treatment method ($kg\ CO_2e/kg$))

EXAMPLE 6 Estimating emissions from refinery products that are not sold as fuel

The refinery in Example 5.1 estimates the end-of-life treatment for their products that are not consumed as fuel by estimating the treatment method at the end of life and applying the associated emission factors.

Product	Amount disposed of (million metric tonnes)	Waste treatment	Proportion of waste (%)	EF of waste treatment method (metric tonne CO_2e per metric tonne product)	Emissions from end-of life treatment (million metric tonnes)
Naphtha	4	Landfill	50%	0.04	0.2
		Incinerated	20%	3.3	13.0
		Recycled	30%	0	-
Lubricants/waxes	1	Landfill	20%	0.04	0.0
		Incinerated	40%	2.9	2.9
		Recycled	40%	0	-
Asphalt and road oil	1	Landfill	30%	0.04	0.0
		Incinerated	10%	3.2	3.2
		Recycled	60%	0	-
				Total:	19.3

Note: the activity data and emissions factors are illustrative only and do not refer to actual data.

Some companies estimate waste treatment methods based on final products (for example by using the waste treatment pathways for plastics for naphtha). As discussed in Section 3.5, the GHG Protocol Scope 3 Standard notes that companies should not account for emissions from recycling processes in Category 12. In addition, companies should not account for negative or avoided emissions associated with recycling in scope 3, but should instead account for these separately from scope 1, scope 2 and scope 3 emissions. For example, companies whose products are recycled should not include emissions from the recycling process, but should also not deduct emissions associated with displacing virgin materials.

Because incineration accounts for the majority of end-of-life emissions, a company may typically opt to assume that all of their products are incinerated at the end of life as a screening assessment.

Emission factors

Table 17 provide references for emissions factors that petroleum companies typically apply to estimate the proportion of waste treated by different methods and emission factors for end-of-life treatment of petroleum specific products.

Additional detail, examples and emission factor resources for applying end-of-life treatment of sold products estimation methods are available in Chapter 12 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

Table 17 Emission factor references for end-of-life disposal relevant to petroleum companies

REFERENCE	FACTORS INCLUDED	LOCATION
EPA (2015). Waste Reduction Model (WARM) Geography: United States	Emission factors for source reduction, recycling, combustion, composting, and landfilling by material type (asphalt concrete, asphalt shingles, carpet, concrete, drywall, plastics, tires, vinyl flooring)	https://www.epa.gov/warm
EPA. Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures Geography: United States	The most recent available data on annual U.S. waste generation, recycling, and disposal, as well as the benefits of recycling.	https://www.epa.gov/smm/advancing-sustainable-materials-management-facts-and-figures
International Council of Chemical Associations (ICCA) (2009). *Innovations for Greenhouse Gas Reductions* Geography: Global	Emissions from the disposal of chemicals and lubricants.	https://www.americanchemistry.com/Policy/Energy/Climate-Study/Innovations-for-Greenhouse-Gas-Reductions.pdf

3.13 DOWNSTREAM LEASED ASSETS

3.13.1 Category description

Downstream leased assets include assets owned by the company (lessor) and leased to other entities. Emissions in this category could include capacity rights at major installations owned but not operated by a company who is accounting using an operational control basis rather than an equity boundary approach, and company-owned facilities or equipment that are leased and used by customers.

Boundary Considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Depending on the petroleum company boundaries and operations, retail operations may be classified into multiple scopes and categories, as illustrated in Table 13 in section 3.8.1. Companies should include retail operations in Category 13 (downstream leased assets) if they lease retail facilities to other entities and do not already include these emissions in their scope 1 and 2 emissions. Rather than split emissions from retail operations into multiple categories, some companies choose to group all retail operations into one category (e.g. the category with the largest emissions based on company operations and boundaries) to provide stakeholders with an aggregate retail value.

3.13.2 Materiality considerations

Companies with significant leased assets should consider a screening evaluation at a minimum to confirm materiality of this emissions category. Some companies with third-party service stations owned by the company and leased to other entities estimate Category 13 emissions.

3.13.3 Estimating emissions

The estimation methods for downstream leased assets are the same as those presented in section 3.8.3 for upstream leased assets (Category 8). Downstream leased assets differ from Category 8 upstream leased assets in that upstream leased assets are owned by the accounting company. Because downstream leased assets are not under a company's operational control, some companies request data from lessees in order to calculate emissions.

Additional detail, examples and emission factor resources for leased asset calculation methods are available in Chapters 8 and 14 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.14 FRANCHISES

3.14.1 Category description

Franchises are not a common emission source for oil and gas companies; some companies that have licensed branded sites (e.g. service stations) that are not included in scope 1 and scope 2 emissions may have associated franchise emissions.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Depending on the petroleum company boundaries and operations, retail operations may be classified into multiple scopes and categories, as illustrated in Table 13 in section 3.8.1. Some companies include retail operations in Category 14 (franchises) if they grant licences to other entities to sell or distribute their products in return for payments, such as royalties for the use of trademarks and other services. Rather than split emissions from retail operations into multiple categories, some companies choose to group all retail operations into one category (e.g. the category with the largest emissions based on company operations and boundaries) to provide stakeholders with an aggregate retail value.

3.14.2 Materiality considerations

Franchises are not a material category for the majority of oil and gas companies.

3.14.3 Estimating emissions

Oil and gas companies typically use one of the following methods to estimate emissions from franchises:

- **Average-data method:** estimate emissions from each franchise based on average statistics such as average emissions per franchise type or floor space.
- **Franchise-specific method:** collect site-specific scope 1 and 2 emissions data from franchises.

Further detail for the average-data method is described below. Franchise-specific scope 1 and scope 2 information is less likely to be available or appropriate for petroleum companies.

Average-data method

Companies often apply the average-data method to estimate emissions from franchises based on average statistics and secondary data, such as average emissions per franchise type or floor space.

CO_2e emissions from franchises buildings (based on floor space) =

Sum across franchise types:

$\sum$ (total floor space of franchises type (m_2) x average emission factor for franchise type (kg CO_2e/m^2/year))

CO_2e emissions from franchises (not based on floor space) =

Sum across franchise types:

$\sum$ (number of franchises x average emission per franchise type (kg CO_2e/franchise/year))

Some petroleum companies estimate the emissions for a subset of franchises, extrapolating the average franchise or average franchise emissions per square foot to the larger set of facilities.

Additional detail, examples and emission factor resources for applying franchise estimation methods are available in Chapter 14 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

3.15 INVESTMENTS

3.15.1 Category description

This category accounts for emissions from the operation of investments, including equity and debt investments and project finance. Also included are emissions from joint ventures and ownership shares in facilities not operated by the company or otherwise included in a company's scope 1 and 2 boundary.

Boundary considerations and relationship to scope 1 and 2 emissions and other scope 3 categories

Petroleum companies often have complex accounting boundaries and approaches, influenced by joint ventures and investments. See section 3.1.2 of the IPIECA Scope 1 & 2 Guidance (IPIECA, 2011) for details on applications of equity share and control approaches within the petroleum industry. Scope 3 emissions within Category 15 (investments) include emissions associated with investments that are not otherwise captured in publically reported scope 1 and 2 emissions data.

3.15.2 Materiality considerations

Investment emissions are potentially material for those companies with significant investments and joint ventures that are not captured in their scope 1 and 2 inventory, as reported in publically available data. These emissions are typically small, although they will depend on the nature and size of the investments. Companies with considerable investments, for example companies that have investments at major installations such as refineries, should consider a screening level assessment to confirm materiality of Category 15 emissions for their company-specific investments.

3.15.3 Estimating emissions

Oil and gas companies often use one of the following methods to estimate emissions from investments:

- Investment-specific method: collect scope 1 and scope 2 emissions or activity data from the investee company or project, or own emissions factors from similar operations under operational control and allocate the emissions based on the share of investment.
- Average-data method: use revenue data combined with EEIO data to estimate emissions from the investee company and allocate emissions based on the share of the investment.

The investment-specific and average-data methods are described below. Sources of data may include the GHG inventory reports of investment companies, and financial records of the accounting company.

Investment-specific method

CO_2e emissions from investments =

Sum across investments:

∑ (scope 1 and scope 2 emissions of investment) x share of equity (%))

Average-data method

The average-data method uses EEIO data to estimate scope 1 and scope 2 emissions associated with investments based on the revenue of the company in combination with the EEIO emission factor that is representative of the investee company's sector of the economy. Although EEIO data does not differentiate between investments within a particular sector, it can be used to perform a screening assessment to evaluate the rough order of magnitude of investment activities and to identify those investments that may warrant estimation applying investment-specific data.

CO_2e emissions from investments =

Sum across investments:

∑ (Investee company total revenue ($) x emission factor for investee's sector (kg CO_2e/$ revenue) x share of equity (%))

Additional detail, examples and emission factor resources for applying franchise estimation methods are available in Chapter 15 of the GHG Protocol Scope 3 Calculation Guidance (WRI/WBCSD, 2013).

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Section 4

Considerations of optional assurance

This section is applicable to companies that choose to implement an assurance process, and offers a summary of:

- the key benefits of assurance;
- the assurance process;
- levels of assurance; and
- complexities of assuring scope 3 inventories due to increased uncertainty of scope 3 emissions.

Considerations of optional assurance

The GHG Protocol Scope 3 Standard (WRI/WBCSD, 2011) defines assurance as the level of confidence that the inventory is complete, accurate, consistent, transparent, relevant and without material misstatements. For those companies that choose to implement an assurance process, this section describes the benefits of assurance, the assurance process and levels, and the scope 3 assurance challenges due to increased uncertainty. Information for this section was obtained primarily from Chapter 10 of the GHG Protocol Scope 3 Standard.

The benefits of assuring scope 3 inventory results can include:

- increased senior management support of accounting information;
- increased stakeholder confidence in reported information;
- improved internal accounting and reporting practices (e.g. data collection, calculation, and internal reporting or management systems);
- improved learning and knowledge transfer; and
- increased efficiency in future inventory updates.

Assurance can be completed within the company (known as first-party assurance) or with an independent organization external to the company (known as third-party assurance). First-party and third-party assurance processes typically follow an assurance standard[7] and include:

- planning and scoping the assurance process including determining criteria[8], risk and material misstatements;
- identifying the sources included in the scope 3 inventory;
- implementing the assurance process including gathering evidence[9], performing calculation checks, and verifying emission factors;
- re-evaluating the scope 3 results; and
- determining and reporting conclusions.

The rigor of the aforementioned assurance process and the subject matter[10] that the assurer will assess is determined by the level of assurance requested by the company. The level of assurance is the degree of confidence that stakeholders can have in the inventory results. These levels include limited or reasonable assurance. Companies that pursue verification of their Scope 3 inventory may choose to start with a limited assurance assessment.

In a *limited assurance* assessment, the assurer will give a negative opinion that the assurer is not aware of any material misstatements or modifications that should be made to the company's assertion that their scope 3 emissions inventory is in conformance with the standard

[7] An assurance standard is a standard used by assurers, which set requirements on how the assurance process is performed. (For example, ISO 14064-3: Specification with Guidance for the Validation and Verification of Greenhouse Gas Assertions).

[8] Criteria are the benchmarks used to evaluate or measure the subject matter, including the standard's requirements, methodological choices, data quality, uncertainty, etc.

[9] Evidence includes data sources and documentation used to calculate emissions and support the subject matter of the reporting company's assertion. It should be sufficient in quantity and appropriate in quality.

[10] Subject matter is the scope 3 emissions by category and supporting information included in the inventory report.

followed, i.e. the assurer determines that nothing was found to be incorrect with the data that was evaluated.

A *reasonable assurance* assessment is more rigorous than an assessment for limited assurance. In this case the assurer will give a positive opinion[11] that the company's assertion[12] of their scope 3 emissions is fairly stated in all material aspects and is in conformance with the standard followed, i.e. the assurer is satisfied that there is sufficient evidence to be confident that the inventory data is correct.

A material misstatement occurs when individual or aggregate errors, omissions and misrepresentations have a significant impact on the GHG inventory results. Materiality has quantitative and qualitative aspects. The materiality threshold is determined by the assurer and the accounting company during the assurance process. An example of a quantitative threshold is the percentage of the inventory (total, by scope, or other line item). Assurers also check for qualitative misstatements that could lead to quantitative material misstatements in the future or misinform the intended audience.

The increased uncertainty of scope 3 emissions calculations poses several challenges to the assurance process, including:

- It is difficult to assess the integrity of the data and methodological choices, because emissions calculations rely on a mixture of data sources and assumptions, which affect the uncertainty of the inventory.
- Emission factors are typically from secondary sources, which are not in the accounting company's control, which makes it difficult for the assurer to verify factors against appropriate evidence.

[11] An assurance opinion is the results of the assurer's assessment of the reporting company's assertion. In the event that the assurer determines that a conclusion cannot be expressed, the statement should cite the reason.

[12] An assertion is a statement by the reporting company on the company's scope 3 emissions by category and conformance to a given reporting standard, which is presented to the assurer.

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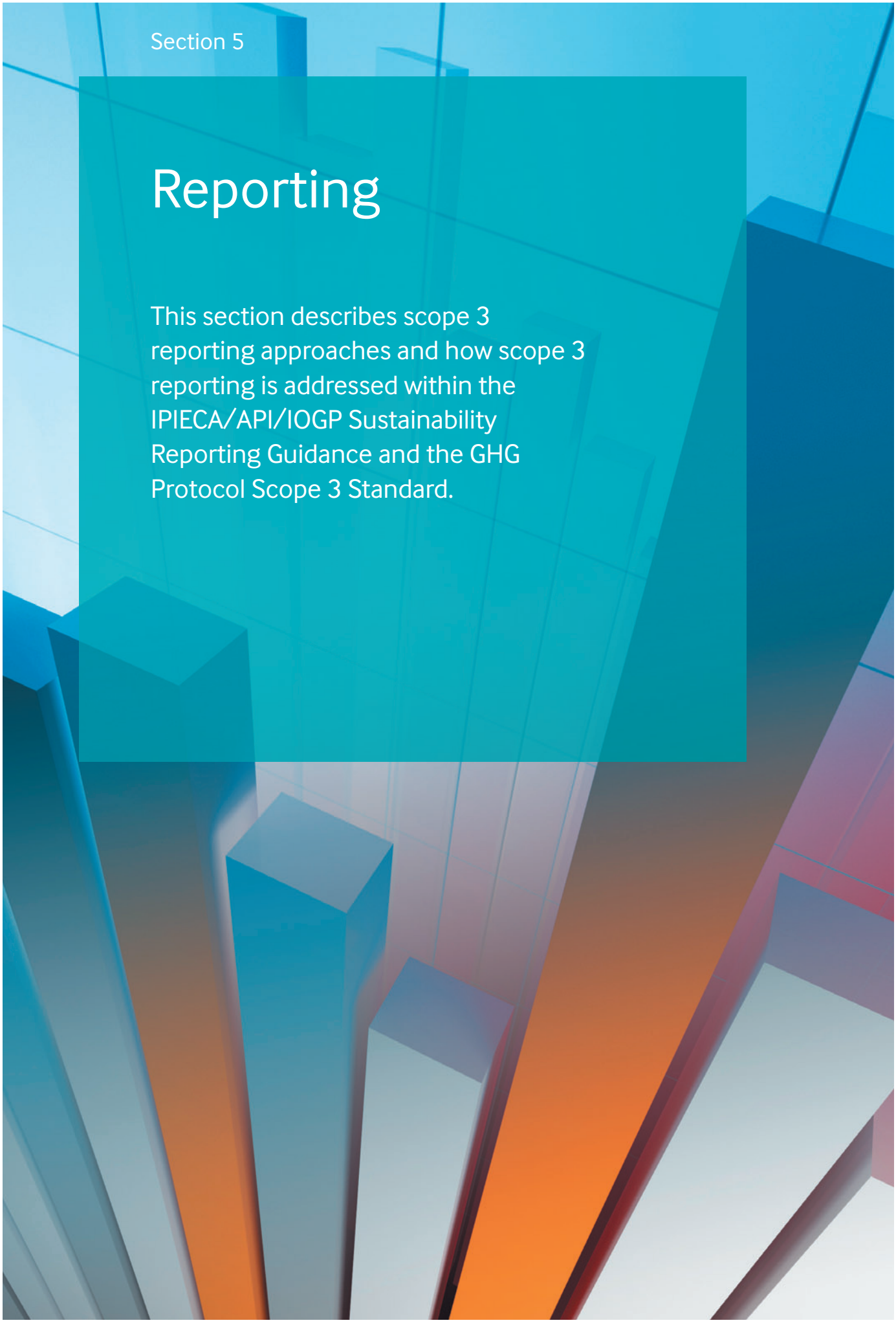
Section 5

Reporting

This section describes scope 3 reporting approaches and how scope 3 reporting is addressed within the IPIECA/API/IOGP Sustainability Reporting Guidance and the GHG Protocol Scope 3 Standard.



Reporting

IPIECA SUSTAINABILITY REPORTING GUIDANCE

The IPIECA/API/IOGP guidance on voluntary sustainability reporting (IPIECA/API/IOGP, 2015) specifically states that '*Companies may report Other indirect emissions (Scope 3) related to the value chain of their activities (see page 30)*'. Of the 15 categories of Scope 3 emissions defined by The GHG Protocol, Category 11 (use of sold products) is the most relevant in relation to the oil and gas industry. While there are a variety of methodologies (both regulated and voluntary) for estimating consumer emissions and such data may be more comprehensively reported by governments on a societal basis (e.g. by country, region, etc.), companies may provide estimates of emissions related to product use in their reports. As an alternative, companies may provide applicable product volumes (such as oil and gas production, refined products, retail sales, etc.) to enable stakeholders to estimate emissions using their preferred methodology. The **common** reporting elements (see page 45 of the IPIECA/API/IOGP guidance) are based on reporting direct GHG emissions and indirect GHG emissions associated with purchased energy (scope 1 and 2); the **supplemental** reporting elements allow for more detailed reporting on direct GHG emissions and provide for reporting indirect GHG emissions related to consumer use of products (scope 3).

Companies that choose to report on GHG emissions related to consumer use of oil and gas products (scope 3) should clarify the types of product (such as crude oil, gas or other production, fuels and other refinery outputs, direct retail sales, etc.) selected as a basis for the methodology used to estimate the emissions and also the source of emission factors applied, e.g. reports of the IPCC.

The IPIECA/API/IOGP Sustainability Reporting Guidance includes reporting of scope 3 emissions as a reporting element for the Climate Change and Energy environmental indicator E1: Greenhouse gas emissions. The guidance classifies Category 11 (use of sold products) as a **supplemental** element, and all other Categories of scope 3 emissions as **other** reporting elements—these are shown in context with other greenhouse gas reporting elements in Figure 7 on page 69.

GHG PROTOCOL SCOPE 3 STANDARD REPORTING SUMMARY

As discussed throughout this *Overview of methodologies*, oil and gas companies determine which scope 3 categories to report based on category materiality depending on the company boundaries and operations. Companies can refer to each scope 3 category section presented in this document for petroleum industry-specific details on the materiality considerations that should be taken into account when assessing the categories and level of reporting detail that is appropriate for them. Therefore, while the *GHG Protocol Scope 3 Standard* describes reporting of the detailed information below, petroleum companies will likely focus on only a few material categories.

- Total scope 3 emissions reported separately by scope 3 category.
- For each scope 3 category, total emissions of GHGs (CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6) reported in metric tonnes of CO_2 equivalent, excluding biogenic CO_2 emissions and independent of any GHG trades, such as purchases, sales, or transfers of offsets or allowances.
- A list of scope 3 categories and activities included in the inventory.
- A list of scope 3 categories or activities excluded from the inventory with justification of their exclusion.
- Once a base year has been established: the year chosen as the scope 3 base year (scope 3 base years may be category specific); the rationale for choosing the base year; the base year emissions recalculation

Common reporting elements	Supplemental reporting elements
C1 Direct GHG emissions (Scope 1), reported using the company's preferred approach (operational, equity share or other) to include: • Direct CO_2 • Direct CH_4 • Direct other gases (if significant). C2 Indirect GHG emissions related to imported energy, reported separately from direct emissions, using the same approach (Scope 2). C3 GHG emissions and/or intensity, reported by business activity (e.g. oil and gas production, refining).	S1 Direct GHG emissions (Scope 1), reported using both operational and equity share approaches. S2 Indirect GHG emissions related to consumer use of oil and gas products (Scope 3). Alternatively, provide applicable product volumes (such as oil and gas production, refined products, retail sales, etc.) to enable stakeholders to estimate emissions using their preferred methodology.

Other reporting elements
O1 Breakdown of major source categories for both CO_2 and CH_4 emissions (e.g. combustion [stationary], flaring, venting, process, product transport). O2 Emissions related to activities of special interest (e.g. oil sands) can be noted separately if these represent a substantial portion of the company's GHG profile. O3 Separately report substantial direct GHG emissions associated with the cogeneration of heat and power. O4 Separately report substantial direct GHG emissions related to the generation of energy exported. O5 Report other Scope 3 categories of indirect GHG emissions as listed within the GHG Protocol (noting that companies may have chosen to report indirect emissions related to consumer use of products as a **supplemental** reporting element).

Figure 7
Classification of scope 3 reporting in the IPIECA/API/IOGP Sustainability Reporting Guidance greenhouse gas environmental indicator (E1)

Source: IPIECA/API/IOGP (2015), p. 45.

policy; scope 3 emissions by category in the base year, consistent with the base year emissions recalculation policy; and appropriate context for any significant emissions changes that triggered base year emissions recalculations.

- For each scope 3 category, any biogenic CO_2 emissions reported separately.
- For each scope 3 category, a description of the types and sources of data, including activity data, emission factors and GWP values, used to calculate emissions, and a description of the data quality of reported emissions data, if appropriate. If companies utilize aggregate information from secondary data sources (such as CO_2e emissions per product obtained from a supplier) they can reference the source and provide details to the extent that they are available.
- For each scope 3 category, a description of the methodologies, allocation methods, and assumptions used to calculate scope 3 emissions. For example, for Category 11 (use of sold products), companies should report methodologies and assumptions used to determine the amounts and types of sold products, and should note any instances of potential double counting between categories.
- For each scope 3 category, the percentage of emissions calculated using data obtained from suppliers or other value chain partners.

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Glossary

Glossary

Activity data	A quantitative measure of a level of activity that results in GHG emissions. Activity data is multiplied by an emissions factor to derive the GHG emissions associated with a process or an operation. Examples of activity data include kilowatt-hours of electricity used, quantity of fuel used, output of a process, hours equipment is operated, distance travelled, and floor area of a building.
Allocation	The process of partitioning GHG emissions from a single facility or other system (e.g, vehicle, business unit, corporation) among its various outputs.
Assurance	The level of confidence that the inventory and report are complete, accurate, consistent, transparent, relevant and without material misstatements.
Base year	A historical datum (e.g. year) against which a company's emissions are tracked over time.
Biogenic CO_2 emissions	CO_2 emissions from the combustion or biodegradation of biomass.
Capital goods	Final goods that have an extended life and are used by the company to manufacture a product, provide a service, or sell, store, and deliver merchandise. In financial accounting, capital goods are treated as fixed assets or plant, property and equipment (PP&E). Examples of capital goods include equipment, machinery, buildings, facilities, and vehicles and materials such as steel and concrete.
CO_2 equivalent (CO_2e)	The universal unit of measurement to indicate the global warming potential (GWP) of each greenhouse gas, expressed in terms of the GWP of one unit of carbon dioxide. It is used to evaluate releasing (or avoiding releasing) different greenhouse gases against a common basis.
Cradle-to-gate	All emissions that occur in the life cycle of purchased products, up to the point of receipt by the reporting company (excluding emissions from sources that are owned or controlled by the reporting company).
Direct emissions	Emissions from sources that are owned or controlled by the reporting company.
Downstream emissions	Indirect GHG emissions from sold goods and services.
Emission factor	A factor that converts activity data into GHG emissions data (e.g., kg CO_2e emitted per litre of fuel consumed, kg CO_2e emitted per kilometre travelled, etc.).
Emissions	The release of greenhouse gases into the atmosphere.
Equity share approach	A consolidation approach whereby a company accounts for GHG emissions from operations according to its share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and rewards flowing from an operation.

Extrapolated data	Data from a similar process or activity that is used as a stand-in for the given process or activity, and has been customized to be more representative of the given process or activity.
Final product	Goods and services that are consumed by the end user in their current form, without further processing, transformation, or inclusion in another product.
Financial control approach	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has financial control. It does not account for GHG emissions from operations in which it owns an interest but does not have financial control.
Franchise	A business operating under a licence (granted by a franchisor) to sell or distribute the franchisor's goods or services within a certain location.
Global warming potential (GWP)	A factor describing the radiative forcing impact (degree of harm to the atmosphere) of one unit of a given GHG relative to one unit of CO_2.
Greenhouse gas inventory	A quantified list of an organization's GHG emissions and sources.
Greenhouse gases (GHGs)	For the purposes of this guidance, GHGs are the six gases covered by the UNFCCC: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); and sulphur hexafluoride (SF_6).
Indirect emissions	Emissions that are a consequence of the activities of the reporting company, but occur at sources owned or controlled by another company.
Intermediate product	Goods that are inputs to the production of other goods or services that require further processing, transformation or inclusion in another product before use by the end consumer. Intermediate products are not consumed by the end user in their current form.
Materiality	Complete set of qualitative issues and magnitude relevant to both the company and its stakeholders. Materiality in this sense indicates that something is material to users of the GHG inventory and decision making influenced by the inventory and is entirely separate from materiality in any other sense, such as the use of financial reporting information.
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the reporting company.
Operational control	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has operational control. It does not account for GHG emissions from operations in which it owns an interest but does not have operational control.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting company, depending on the consolidation approach taken (equity or control approach).
Outsourcing	The contracting out of activities to other businesses.
Primary data	Data from specific activities within a company's value chain.
Process	A set of interrelated or interacting activities that transforms or transports a product.

Proxy data	Data from a similar process or activity that is used as a stand-in for the given process or activity without being customized to be more representative of the given process or activity.
Reporting year	The year for which emissions are reported.
Scope 1 emissions	Emissions from operations that are owned or controlled by the reporting company.
Scope 2 emissions	Emissions from the generation of purchased or acquired electricity, steam, heating or cooling consumed by the reporting company.
Scope 3 activity	An individual source of emissions included in a scope 3 category.
Scope 3 category	One of the 15 types of scope 3 emissions.
Scope 3 emissions	All indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream (indirect GHG emissions from purchased or acquired goods and services) and downstream (indirect GHG emissions from sold goods and services) emissions.
Secondary data	Data that is not from specific activities within a company's value chain.
Service	An intangible product.
Supplier	An entity that provides or sells products to another entity (i.e. a customer).
Supply chain	A network of organizations (e.g. manufacturers, wholesalers, distributors and retailers) involved in the production, delivery, and sale of a product to the consumer.
Tier 1 supplier	A supplier that provides or sells products directly to the reporting company. A tier 1 supplier is a company with which the reporting company has a purchase order for goods or services.
Tier 2 supplier	A supplier that provides or sells products directly to the reporting company's tier 1 supplier. A tier 2 supplier is a company with which the reporting company's tier 1 supplier has a purchase order for goods and services.
Uncertainty	1. *Quantitative definition:* measurement that characterizes the dispersion of values that could reasonably be attributed to a parameter. 2. *Qualitative definition:* A general and imprecise term that refers to the lack of certainty in data and methodology choices, such as the application of non-representative factors or methods, incomplete data on sources and sinks, lack of transparency etc.
Upstream emissions	Indirect GHG emissions from purchased or acquired goods and services.
Value chain	All of the scope 3 upstream and downstream activities associated with the operations of the reporting company, including the use of sold products by consumers and the end-of-life treatment of sold products after consumer use.
Value chain emissions	Emissions from the scope 3 upstream and downstream activities associated with the operations of the reporting company.
Waste	An output of a process that has no market value.

Acronyms and abbreviations

Acronyms and abbreviations

ABS	Acrylonitrile butadiene styrene
API	American Petroleum Institute
Bbl	Barrels
BOE	Barrel of oil equivalent
BPA	Bisphenol A
CDP	Carbon Disclosure Project
CFC	Chlorofluorocarbon
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
DEFRA	Department for Environment, Food and Rural Affairs
ECF	Energy conversion facility
EEIO	Environmentally extended input-output analysis
EF	Emissions Factors
EIA	Energy Information Administration
EIO-LCA	Economic input-output life cycle assessment
ELCD	European reference life cycle database
EPA	United States Environmental Protection Agency
ESG	Environmental, social and governance
EU ETS	European Union Emissions Trading System
GHG	Greenhouse gas
GPPS	General purpose polystyrene
GWP	Global warming potential
HCFC	Hydrochlorofluorocarbons
HDPE	High density polyethylene
HFC	Hydrofluorocarbon
HIPS	High impact polystyrene
ICCA	International Council of Chemical Associations
IEA	International Energy Association
ICE	Inventory of carbon and energy
ISSE	International Stainless Steel Federation
IISI	International Iron and Steel Institute
IO&G	Integrated oil and gas
kg	kilogram
km	kilometre
kWh	kilowatt-hour
l	litre
LCA	Life-cycle analysis
LDPE	Low density polyethylene
LLDPE	Linear low density polyethylene
MDI	Methylene diphenyl diisocyanate
N_2O	Nitrous oxide
NAPA	National Asphalt Pavement Association
NETL	National Energy Technology Laboratory
NF_3	Nitrogen trifluoride
NGL	Natural gas liquid
NO_x	Nitrogen oxides (NO and NO_2)
OPGEE	Oil production greenhouse gas emission estimator
PET	Polyethylene terephthalate
PFC	Perfluorocarbon
PI	Petroleum industry
PMMA	Polymethyl methacrylate
PP	Polypropylene
PVC	Polyvinyl chloride
SF_6	Sulphur hexafluoride
TDI	Toluene diisocyanate
T&D	Transmission and distribution
USLCI	US Life Cycle Inventory Database
WARM	Waste reduction model
WBCSD	World Business Council for Sustainable Development
WRI	World Resource Institute

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IPIECA

IPIECA is the global oil and gas industry association for environmental and social issues. It develops, shares and promotes good practices and knowledge to help the industry improve its environmental and social performance, and is the industry's principal channel of communication with the United Nations.

Through its member-led working groups and executive leadership, IPIECA brings together the collective expertise of oil and gas companies and associations. Its unique position within the industry enables its members to respond effectively to key environmental and social issues.

energy API

The American Petroleum Institute is the primary trade association in the United States representing the oil and natural gas industry, and the only one representing all segments of the industry.

Representing one of the most technologically advanced industries in the world, API's membership includes more than 400 corporations involved in all aspects of the oil and gas industry, including exploration and production, refining and marketing, marine and pipeline transportation and service and supply companies to the oil and natural gas industry. API is headquartered in Washington, D.C. and has offices in 27 state capitals and provides its members with representation on state issues in 33 states. API provides a forum for all segments of the oil and natural gas industry to pursue public policy objectives and advance the interests of the industry. API undertakes in-depth scientific, technical and economic research to assist in the development of its positions, and develops standards and quality certification programmes used throughout the world. As a major research institute, API supports these public policy positions with scientific, technical and economic research.

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