EIB Project Carbon Footprint Methodologies

Methodologies for the Assessment of Project GHG Emissions and Emission Variations

Version 11.1
July 2020

CAVEAT

A number of caveats should be stressed from the outset.

First, carbon emissions result from virtually all human and natural activities. For example, even when the best available technologies are used when making cement, paper or steel, inevitably a significant quantity of CO_2 is emitted. The carbon footprint measures GHG emissions. However, evaluating the merit of a project requires comparing economic costs with benefits, including the costs and benefits in terms of incremental GHG emissions. Where appropriate, the Bank uses an economic (shadow price) of carbon to convert changes in tonnes of GHG into euros. In short, whilst the carbon footprint is an important metric in its own right, it should be seen within the context of the overall economic appraisal of a project.

Second, the recommended methodologies are by assumption restricted in scope. The carbon footprint does not purport to be a comprehensive life-cycle analysis of a project. Such an exercise can only be done credibly ex-post and with a large amount of information. The carbon footprint takes place ex-ante and with limited information and resources. For instance, downstream emissions from the use of the products and services resulting from EIB-financed investment projects are generally not considered. Examples are R&D projects in the area of efficient engines, a project to build a PV panel or wind turbine factory, and a bio-ethanol refinery project.

In summary, in considering the scope and nature of the EIB carbon footprinting methodology, readers should be mindful that the carbon footprint of a project per se cannot and should not be construed as an expression of the merit or value of that project, either broadly or more narrowly in climate change terms alone.

Finally, the EIB carbon footprint methodology is considered “work in progress” that is subject to periodic review and revision in the light of experience gained and as knowledge of climate change issues evolves. The EIB’s Projects Directorate (PJ) welcomes comments and suggestions for improvement on the latest draft of the present document.

EIB Project Carbon Footprint Methodologies

For further information on the EIB’s activities, please consult our website, www.eib.org. You can also contact our InfoDesk, info@eib.org.

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REVISION HISTORY

Revision No.	Issue Date	Amendment Description
Version 1	10 July 2009	First version issued following consultations on two draft editions.
v2	10 Sept 2009	Revisions to incorporated changes following internal review
v3	24 Sept 2009	Revisions to incorporated changes following launch of methodologies
v4	22 Oct 2009	Revisions following implementation of methodologies
v5	10 Nov 2009	Revisions to included amended baseline methodologies
v6	23 Nov 2009	Revisions following internal review
v7	24 Feb 2010	Revisions following internal review
v8	15 July 2010	Revision following internal review and comments
v9.1	29 Sept 2010	Revision following internal review and comments
v9.2	Q1 2012	Holding version after preliminary review by the Carbon Footprint Task Force. Issued before CSO Workshop
v10	Q3 2012	Revision following feedback from PJ CFTF[1], CSOs, MDB Working Group and the completion of the 3 year Pilot.
v10.1	Q1 2014	Table A1.3 updated with IEA data for 3-year average, 2009-2011
v10.2 (internal)	Q4 2014	Revisions following CO2logic review of v10 and KPMG audit of CFE 2013
v10.3 (internal)	Q2 2016	Table A1.3 updated with IEA data for 3-year average (2011-2013)
v10.4 (internal)	Q4 2017	Improved clarification of absolute and relative boundaries, updated table A1.3
v11	Q4 2018	Revision of threshold for absolute emissions Included methodologies for ports, airports and forestry Improved definition of scopes and boundaries Updated emission factors Alignment with IFI GHG Harmonised Methodologies
v11.1	Q3 2020	Clarification emission factors biomass, emissions from purchased renewable electricity and from iron and steel production Improvements to the forestry methodology Explanation of EX-ACT tool for land use change carbon balance calculation Updated emission factors for electricity

[1] The Carbon Footprint Task Force – group made up of a minimum of several experts from each Department in the EIB's Project Directorate tasked with reviewing sector methodologies.

Contents

1. Introduction

This document contains the carbon footprinting methodology of the EIB. It provides guidance to EIB staff on how to calculate the carbon footprint of the investment projects financed by the EIB. The document also presents how the EIB calculates the carbon footprint of its investment projects to its auditors, external stakeholders and other interested parties.

The methodology is used to calculate the carbon footprint of the investment projects financed by the EIB. These carbon footprints are published on the project's Environmental and Social Data Sheet (ESDS). The EIB also publishes the aggregated results annually as part of its Carbon Footprint Exercise (CFE) in the EIB Group's Sustainability Report.

Whilst project carbon footprinting is mainstreamed into the Bank's operations, it remains under regular review. The Bank works closely with other financial institutions and stakeholders in its footprinting work and welcomes further feedback on the methodology. The EIB's methodology is in line with the International Financial Institution Framework for a Harmonised Approach to Greenhouse Gas Accounting, published in November 2015.

The methodologies presented here are for project carbon footprinting and should not be confused with the internal carbon footprint of the EIB Group's travel and buildings, which is reported separately. In addition, the carbon footprinting methodology should not be confused with the EIB's Climate Action eligibility list, which can be found separately on the EIB's website.

2. Background

Most of the projects financed by the EIB emit greenhouse gases (GHG) into the atmosphere either directly (e.g. fuel combustion or production process emissions) or indirectly through purchased electricity and/or heat. In addition, many projects result in emission reductions or increases when compared to what would have happened in the absence of the project, referred to as baseline emissions.

The Bank carried out a 3-year pilot phase from 2009-2011 to measure the impact in GHG emissions from the investment projects it finances[2]. This document sets out the methodologies to be applied going forward. The methodologies allow for the estimation of two measures of GHGs from investment projects financed by the Bank:

- the absolute GHG emissions or sequestration of the project, and;
- the emissions variation of the project i.e. the relative GHG emissions of the project, which is the difference in emissions between the "with" and the "without" project scenarios. Relative emissions can be either positive or negative, based on whether there is an increase or decrease in emissions.

The methodologies set out below are based upon the internationally recognised IPCC Guidelines, the WRI GHG Protocol and the IFI's Harmonised Approach to GHG Accounting. In the absence of project specific factors, the methodologies adopt an IPCC factor applicable at the global or trans-national level (termed tier level 1 in IPCC). The development of the methodologies has also been informed by ISO14064 parts 1 and 2 and the Verified Carbon Standard which provide guidelines for the development of greenhouse gas inventories at the corporate and project levels.

[2] The EIB Carbon Footprint Exercise includes direct Investment Loans and large Framework Loan allocations that cross the significant emissions thresholds defined in section 5. Other intermediated lending is not currently included due to the limited information available to carry out a useful calculation for numerous sub-projects.

3. Objective

The EIB calculates and reports the carbon footprint of the projects it finances to provide transparency on the GHG emissions footprint of its financing activities. The GHG footprint of individual investment projects are reported on the project's Environmental and Social Data Sheet (ESDS). Aggregated results are reported as part of the annual Carbon Footprint Exercise (CFE) in the EIB Group's Sustainability Report.

4. Guiding principles

Certain principles underpin the estimation of project-based absolute and relative GHG emissions. These principles should guide users in cases where the proposed EIB methodologies afford flexibility or discretion, or where a particular situation requires the application of a case specific factor. The application of these principles will help ensure the credibility and consistency of efforts to quantify and report emissions. These principles are:

Completeness
All relevant information should be included in the quantification of a project's GHG emissions and in the aggregation to the total EIB-induced GHG footprint. This is to ensure that there are no material omissions from the data and information that would substantively influence the assessments and decisions of the users of the emissions data and information.

Consistency
The credible quantification of GHG emissions requires that methods and procedures are always applied to a project and its components in the same manner, that the same criteria and assumptions are used to evaluate significance and relevance, and that any data collected and reported allow meaningful comparisons over time.

Transparency
GHG emissions are assessed for individual investment projects with significant emissions at appraisal and reported in the project's Environmental and Social Data Sheet (ESDS), which is published on the EIB website on the public register, when either the absolute or relative threshold of 20,000 tonnes CO_2e emissions/year is crossed. The relative threshold applies to both positive and negative relative emissions, therefore the threshold is +/- 20,000 tonnes CO_2e emissions/per year.

For the purposes of annual reporting the project figures are prorated in proportion to the EIB funding for the project, i.e. financed contract amounts, signed in that year compared to its total investment costs. Thus, if the EIB signs a contract for 25% of a project in a particular year, 25% of the project emissions will be reported in that year. Further contracts may be signed for the same project in subsequent years, and will be accounted for separately in the respective year, again using a prorated approach based on the finance contract amount in that year, ensuring that there is no double counting of the impact of a project.

Clear and sufficient information should be available to allow for assessment of the credibility and reliability of reported GHG emissions. Specific exclusions or inclusions should be clearly identified and assumptions should be explained. Appropriate references should be provided for both data and assumptions. Information relating to the project boundary, the explanation of baseline choice, and the estimation of baseline emissions should be sufficient to replicate results and understand the conclusions drawn.

Conservativeness
EIB should use conservative assumptions, values, and procedures. Conservative values and assumptions are those that are more likely to overestimate absolute emissions and "positive" relative emissions (net increases), and underestimate "negative" relative emissions (net reductions).

Balance
Objective threshold values are used to determine which investment projects are included in the portfolio carbon footprint. This includes investment projects with positive as well as negative impacts.

Accuracy
Carbon footprinting involves many forms of uncertainty, including uncertainty about the identification of secondary effects, the identification of baseline scenarios and baseline emission estimates. Therefore, GHG estimates are in principle approximate. Uncertainties with respect to GHG estimates or calculations should be reduced as far as is practical, and estimation methods should avoid bias. Where accuracy is reduced, the data and assumptions used to quantify GHG emissions should be conservative.

Relevance
Select the GHG sources, GHG sinks, GHG reservoirs, data and methodologies appropriate to the needs of the intended user.

5. Significant emissions

Not all investment projects need to be included in the GHG footprint and only investment projects with significant emissions are to be assessed. Based on the results of the GHG footprint pilot, it was decided to set minimum project thresholds for inclusion in the GHG footprint at 100,000 tonnes CO_2e per year for absolute emissions and 20,000 tonnes CO_2e per year (positive or negative) for relative emissions. Investment projects are included if either one of the thresholds is crossed. When included, both absolute and relative emissions need to be calculated and reported.

The coverage of these thresholds was reassessed in 2018 and the threshold for absolute emissions was lowered to guarantee the desired level of coverage for the EIB. It was clarified that the thresholds are positive as well as negative for both absolute as well as relative emissions. The thresholds are as follows:

- Absolute emissions exceeding 20,000 tonnes CO_2e/year (positive or negative)
- Relative emissions exceeding 20,000 tonnes CO_2e/year (positive or negative)

Research indicates that they capture approximately 95% of the absolute and relative GHG emissions from projects. Investment projects with absolute and relative emissions that do not cross these thresholds are not included in the footprint since they are not considered significant.

Table 1 below illustrates the project types that may be included in the calculation of the GHG footprint. This list and categorisation is for guidance only. Project teams may use a quantitative assessment, expert knowledge based on previous projects or other published sources to determine if a project is likely to be above or below the threshold. Where there is uncertainty, then the full carbon footprint calculation should be undertaken to assess whether the project should be included in the carbon footprint exercise.

The EIB reports 100% of a project's emissions even if the Bank is only contributing a portion of the total project investment cost. At the reporting stage, results are prorated to EIB's share of the financing plan.

Table 1: Illustrative examples of project categories for which a GHG assessment is required

In general, depending on the scale of the project GHG assessment WILL NOT be required	• Telecommunications services • Drinking water supply networks • Rainwater and wastewater collection networks • Small scale industrial waste water treatment and municipal waste water treatment • Property developments • Mechanical/biological waste treatment plants • R&D activities • Pharmaceuticals and biotechnology • Mobile asset projects, trams and BRT systems
In general GHG assessment WILL be required	• Municipal solid waste landfills • Municipal waste incineration plants • Large waste water treatment plants • Manufacturing Industry • Chemicals and refining • Mining and basic metals • Pulp and paper • Rolling stock (incl. metros and larger train fleets), ships, transport fleet purchases • Road and Rail infrastructure • Power transmission lines • Renewable sources of energy • Fuel production, processing, storage and transportation • Cement and lime production • Glass production • Heat and power generating plants • District heating networks • Natural gas liquefaction and re-gasification facilities • Gas transmission infrastructure

6. Greenhouse gases included in the carbon footprint

The greenhouse gases (GHGs) included in the footprint include the seven gases listed in the Kyoto Protocol, namely: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6); and nitrogen trifluoride (NF_3). The GHG emissions quantification process converts all GHG emissions into tonnes of carbon dioxide called CO_2e (equivalent) using Global Warming Potentials (GWP), which can be found in table A1.9 in the Annex.

All footprints of the EIB, absolute and relative, include these seven GHGs and are expressed in tonnes CO_2e.

The following processes/activities usually generate GHGs that may be accounted for using the methodologies:

- CO_2 – stationary combustion of fossil fuels, indirect use of electricity, oil/gas production & processing, flue gas desulphurisation (limestone based), aluminium production, iron and steel production, nitric acid production, ammonia production, adipic acid production, cement production, lime production, glass manufacture, municipal solid waste incineration, transport (mobile combustion)[3]
- CH_4 – biomass decomposition, oil/gas production & processing, coal mining, municipal solid waste landfill, municipal waste water treatment
- N_2O – stationary combustion of fossil fuels/biomass, nitric acid production, adipic acid production, municipal solid waste incineration, municipal waste water treatment, transport (mobile combustion)
- HFCs – refrigeration / air conditioning / insulation industry
- PFCs – aluminium production
- SF_6 – electricity transmission systems, specific electronics industries (e.g. LCD display manufacture)
- NF_3 – plasma and thermal cleaning of CVD reactors

Table 2: Selected examples of sources of direct GHG emissions by activity type

ACTIVITY	GHG Type	POTENTIAL SOURCES OF EMISSION
COMBUSTION FOR ENERGY	CO_2 N_2O CH_4	Energy related GHG emissions from combustion: boilers / burners / turbines / heaters / furnaces / incinerators / kilns / ovens / dryers / engines / flares / any other equipment or machinery that uses fuel, including vehicles.
COMBUSTION GAS SCRUBBERS	CO_2	Process CO_2 from flue gas de-sulphurisation (limestone based) units
OIL / GAS PRODUCTION, PROCESSING & REFINING	CO_2 N_2O CH_4	Energy related GHG emissions from combustion: boilers / process heaters & treaters / internal combustion engines & turbines / catalytic and thermal oxidizers / coke calcining kilns / firewater pumps / emergency/standby generators / flares / incinerators / crackers. Process related GHGs from: hydrogen production installations / catalytic regeneration (from catalytic cracking and other catalytic processes) / cokers (flexi-coking, delayed coking). Fugitive losses of CH4.
IRON & STEEL PRODUCTION	CO_2 N_2O	1) Blast furnace / basic oxygen furnace route (BF/BOF): iron ore into steel 2) Direct reduction route (DRI): iron ore to direct reduced iron (DRI) 3) Electric arc furnace route (EAF) – steel recycling route: steel scrap or DRI into steel Sources for 1 / BF/BOF: 1) Coking plant: transformation of coal to coke / sources: coal and some conventional fuels but limited / output emissions: coke oven gas (COG) 2) Sinter plant/ pelletisation: transformation of lump iron ore into sinter or pellets which is a modified form of iron ore / sources: mainly natural gas and to some degree coke and/or, off gases available in the steel plant 3) Blast furnace: transformation from iron ore to pig iron / sources: coke (coming from the coke plant) and coal (pulverized coal injection) and/or natural gas, and/or alternative non-renewable fuels, and process emissions related to the reduction of iron ore.

[3] Note that emissions from the combustion of biomass in e.g. power generation, industry, waste treatment or transport fuels is considered zero due (see footnote 4 and associated explanation earlier in the text).

ACTIVITY	GHG Type	POTENTIAL SOURCES OF EMISSION
		4) Steelshop - basic oxygen furnace (BOF): transformation from pig iron to steel / sources: process emissions related to burning carbon or other elements contained in the pig iron and from burning electrodes (BOFG) COG/BFG/BOFG are mixtures containing N2, CO, CO2 and H2 typically used to fire an electrical power plant. Sources for 2 / EAF: 1) Electric arc furnace (EAF): transformation from scrap or DRI to steel/ sources: electricity from the grid mainly and to some degree firing of natural gas and emissions from burning electrodes Sources for 3 / DRI processes: 1) Different DRI reactors: Transformation from iron ore into direct reduced iron (DRI)/ sources: coal and process emissions or NG and process emissions. 2) Second step is melting DRI in and EAF (electric arc furnace) which is described in 2)
CEMENT & LIME MANUFACTURE	CO_2	Calcination of limestone in the raw materials / conventional fossil kiln fuels / alternative fossil-based kiln fuels and raw materials / refuse-derived fuel (RDF) / non-kiln fuels / organic carbon content of limestone and shales / raw materials used for waste gas scrubbing.
GLASS PRODUCTION	CO_2	Glass production: decomposition of alkali- and earth alkali carbonates during melting of the raw material / conventional fossil fuels / alternative fossil-based fuels and raw materials / other fuels / carbon containing additives including coke and coal dust / waste gas scrubbing.
PAPER & PULP MANUFACTURE	CO_2	Pulp and paper manufacture: power boilers, gas turbines, and other combustion devices producing steam or power for the mill / recovery boilers and other devices burning/recycling spent pulping liquors / incinerators / lime kilns and calciners / waste gas scrubbing / fossil fuel-fired dryers (such as infrared dryers). Fuels predominantly process by-products and rejects such as bark and biomass and to a lesser extent natural gas and other fossil fuels. The recycled paper sector also typically valorises the pulping process rejects that are a mix between cellulose and plastics. Processes wastewater treatment may generate diffuse methane slip form anaerobic digestion.
ALUMINIUM PRODUCTION	CO_2 PFCs SF_6	CO_2 from combustion sources. Process related GHG emissions: CO_2 from anode consumption (pre-baked or Søderberg) / CO_2 from anode and cathode baking / PFCs from anode effects (or events). Other process-related emissions that may occur, depending on the facility configuration, include: CO_2 from coke calcinations / SF6 from use as a cover gas / SF_6 from use in on-site electrical equipment.
NITRIC ACID PRODUCTION	CO_2 N_2O	CO_2 from combustion sources and process related.
AMMONIA PRODUCTION	CO_2	CO_2 from combustion sources and process related.
ADIPIC ACID PRODUCTION	N_2O	CO_2 from combustion sources and process related.
WASTE WATER TREATMENT	CH_4 CO_2 N_2O	CH_4 from degradation of organic material in the wastewater under anaerobic conditions. CO_2 emissions from the consumption of electricity in the treatment process. N_2O as an intermediate product from the degradation of nitrogen components in the wastewater.
MUNICIPAL SOLID WASTE INCINERATION	CO_2 N_2O	GHGs from MSW combustion.
MUNICIPAL SOLID WASTE LANDFILLS	CH_4	CH_4 from anaerobic digestion of biodegradable waste
REFRIGERATION / AIR CONDITIONING / INSULATION INDUSTRY	HFCs	Fugitive losses of HFCs
POWER TRANSMISSION	SF_6	Transmissions losses will be derived from the power production combustion sources and have an associated emission of CO_2 Fugitive losses of SF_6
SPECIFIC ELECTRONICS INDUSTRY (SEMICONDUCTORS, LCD)	PFCs NF_3	Fugitive losses of PFCs and NF_3

7. Project boundaries

The project boundary defines what is to be included in the calculation of the absolute and relative emissions. The EIB methodologies use the concept of "scope" based on definitions from the WRI GHG Protocol 'Corporate Accounting and Reporting Standard', when defining the boundary to be included in the emissions calculation.

Scope 1: Direct GHG emissions. Direct GHG emissions physically occur from sources that are operated by the project. For example emissions produced by the combustion of fossil fuels, by industrial processes and by fugitive emissions, such as refrigerants or methane leakage.

Scope 2: Indirect GHG emissions. Scope 2 accounts for indirect GHG emissions associated with energy consumption (electricity, heating, cooling and steam) consumed but not produced by the project. These are included because the project has direct control over energy consumption, for example by improving it with energy efficiency measures or switching to consume electricity from renewable sources.

Scope 3: Other indirect GHG emissions. Scope 3 emissions are all other indirect emissions that can be considered a consequence of the activities of the project (e.g. emissions from the production or extraction of raw material or feedstock and vehicle emissions from the use of road infrastructure, including emissions from the electricity consumption of trains and electric vehicles).

From the results of the pilot exercise and through working with other IFIs to harmonize approaches to carbon footprinting, it was decided that scope 1 and 2 emissions should be included in the carbon footprint. For the majority of projects financed by the Bank these are the most significant emissions associated with the projects. However, for certain sectors in which the scope 3 emissions associated with the projects are significant and can be estimated, e.g. transportation or biofuel production and bioenergy projects (as required for climate action eligibility), scope 3 emissions may be included.

The EIB is currently assessing to include the upstream emissions from energy sources in its carbon footprint calculations. This would include the upstream emissions of fossil fuels, electricity generation and biomass. In line with international and EU common practice, CO_2 releases form the combustion of biomass is accounted for as 0 (zero)[4]. Emissions related form off field logistics and further processing of the biomass into chips or pellets shall be accounted for following the provisions of the RED II Directive 2018/2001/EU. In the case of biofuels from agricultural biomass, a full life cycle analysis was already foreseen under previous versions of this carbon footprint methodologies and taken into account following the methodologies established in the RED.

Setting of boundaries for absolute and relative emissions calculations
For some projects, as specified in table 3, the absolute and relative emissions calculations may have different boundaries.

- Absolute emissions are based on a project boundary that includes all significant scope 1, scope 2 and scope 3 emissions (as applicable) that occur within the project. For example, the boundary for a stretch of motorway would be the length of motorway defined by the finance contract as the project and the calculation of absolute emissions would cover the GHG emissions of vehicles using that particular stretch of motorway in a typical year.
- Relative emissions are based on a project boundary that adequately covers the "with" and "without" project scenarios. It includes all significant scope 1, scope 2 and scope 3 emissions (as applicable), but it may also require a boundary outside the physical limits of the project to adequately represent

[4] GHG emissions and removals due to and related to the management of forest resources and agricultural land are accounted under the LULUCF Regulation 2018/841 EU and shall not be taken into account for energy combustion purposes. It is scientifically demonstrated that wood removals as part of sustainable forest management practices (such as tending, thinning, and final cuts followed by forest regeneration) increase carbon sequestration at a general forest inventory level in comparison to unmanaged or poorly managed forests. Following IPPC and EU conventions, the accounting of GHG balances at forest level have to be done according to LULUCF Regulation and the carbon footprint of forest biomass for energy purposes is considered 0 (zero), as long as this forest biomass comes from sustainably managed forests (Regulation EU 2018/841, Directive 2018/2001, Regulation (EU) No 601/2012 (3) and Regulation (EU) No 525/2013).

the baseline. For example, without the motorway, traffic would increase on secondary roads outside the physical limits of the project. The relative emissions calculation will use a boundary that covers the entire region affected by the project.

In principle, the absolute and relative emissions footprints are not always directly comparable and should not be added or subtracted from one another.

Table 3: Carbon Footprinting of projects: boundary clarifications

PROJECT TYPE	FOOTPRINT BOUNDARY CLARIFICATION
ALL PROJECTS, (OTHER THAN FOR THOSE EXCEPTIONS SPECIFIED BELOW)	INCLUSION: scope 1 and 2 emissions for a typical year of operation. EXCLUSION: scope 1 and 2 emissions associated with the commissioning, construction and decommissioning of the project. EXCLUSION: scope 3 emissions. INCLUSION: scope 3 emissions from 100% dedicated sources upstream or downstream that would not otherwise exist and a number of specific cases below. An example of the first case would be a power plant that exists solely to supply the project (upstream) or a waste disposal site that is for the exclusive use of the project (downstream) that would not otherwise exist.
TRANSPORT MOBILE ASSETS AND INFRASTRUCTURE	INCLUSION: scope 3 emissions from vehicles travelling on the financed physical infrastructure links, or fleets departing from, or arriving at a transport node, are included in the absolute and the relative emissions calculations. GHG relative emissions are calculated based on the displacement of passengers from one type of transport to another (modal shift effects), shifts in travel patterns (one road to another or from one time of day to another) and the induced increase in passengers and freight traffic. If the project includes the replacement of rolling stock, the savings in emissions from this intervention should also be taken into account.
ENERGY NETWORK PROJECTS	INCLUSION: scope 3 emissions from outside the boundary defined by the physical limits of the project are included in the relative emissions calculation where they are considered significant. For example, a district heating network project typically has a boundary that includes the losses of the heat network and any sources of heat generation under the control of the operator. If the project results in fuel switching (individual heating to district heating) or results in a change of the operational regime of a heat plant outside the control of the project operator, significant GHG emissions from these sources are included.
INDUSTRIAL PRODUCTION FACILITIES	INCLUSION: scope 3 emissions from outside the boundary defined by the physical limits of the project are included in the relative emissions calculation where they are considered significant. For example, the installation of a combined heat and power plant that provides waste heat to a residential area can lead to large GHG savings outside of the project boundary. If an industrial project leads to large energy or GHG emissions outside of the direct project, these should be included. EXCLUSION: The scope 3 emissions upstream and downstream of the industrial production is generally not considered (see exception above under “All Projects” covering 100% dedicated upstream and downstream sources). For example, the use of steel to make wind turbines or glass to double glaze windows would not be considered part of the absolute or relative emissions calculation.
ALL REHABILITATION / REFURBISHMENT PROJECTS	CLARIFICATION: The boundary for absolute emissions calculations for projects that rehabilitate or refurbish existing facilities corresponds to the boundary of the rehabilitation or refurbishment project and not the GHG emissions for the whole facility. If however the GHG emissions of the facility are significantly modified because of the project, the relative emissions calculation shall use a boundary that includes the entire facility.

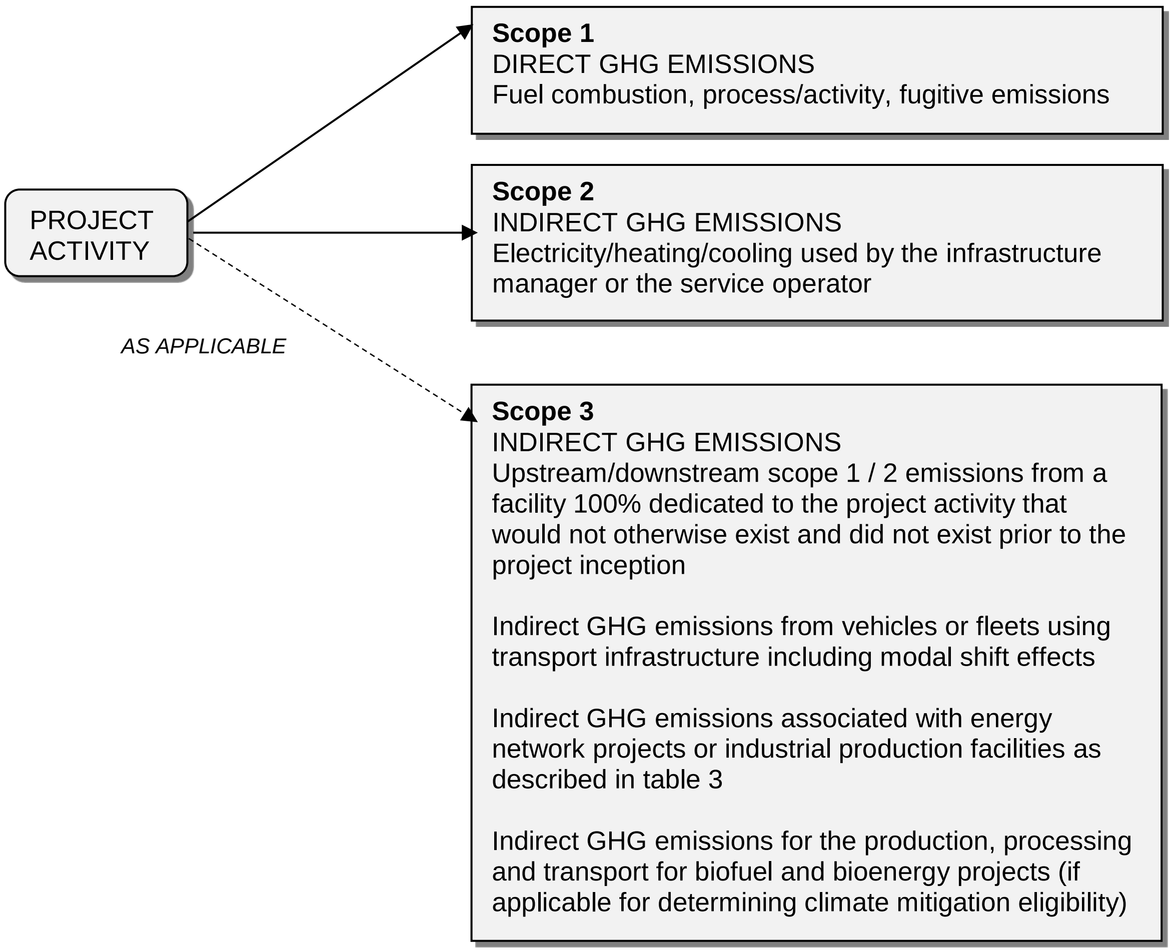
	Example 1: The EIB invests in a project to rehabilitate a boiler house in a manufacturing facility. The EIB reports the scope 1 and 2 emissions of the boiler house for the absolute and relative emissions. If GHG emissions of the rest of the refinery are not affected by the project, EIB does not report the GHG emissions for the whole refinery. Example 2: The EIB invests in a project to replace 5% of an electricity network. The EIB calculates the emissions associated with the project, i.e. losses for 5% of the network. The EIB does not report the whole network losses.

<u>Carbon leakage</u>. Carbon leakage is not considered in the carbon footprint calculations. Leakage normally occurs as a result of climate policies of one country leading to a shift in emissions sources to another but may also occur as the result of a EIB financed project for example when an old technology is replaced and sold on to be used elsewhere (see "Inclusion" on industrial production facilities in Table 3).

<u>Rebound effects</u>. Rebound effects in energy efficiency investments occur when additional energy is consumed because energy efficiency measures make the use of equipment cheaper. This can occur in households (e.g. no need to turn off energy saving lights, because they consume almost no energy anyway) or in industry. These potential effects are not included in the methodology.

Emissions from purchased renewable electricity. For purchased renewable electricity in projects (e.g. Guarantee of Origin labelled green electricity), the emissions need to be calculated using the electricity emission factor for that country, not using an emission factor of zero, unless there is a dedicated renewable electricity plant that provides electricity directly to the project.

Figure 1: Project scope – <u>all projects</u>



8. Metrics

8.1 Emission Factors

The EIB Carbon Footprint Methodology provides a series of emissions factors from which greenhouse gas emissions can be calculated. These have been derived from internationally recognised sources, e.g. WRI/WBCSD's GHG Protocol and IPCC Guidelines for National GHG Inventories. These default factors can be used where no other relevant factor is available or where factors that have been provided, by the promoter for example, appear to be unsubstantiated. Where possible, it is preferable to use project specific factors in place of the defaults given here provided the source of the factors used is consistent with the guiding principles described in section 4 of the methodologies.

8.2 Absolute emissions (Ab)

A project's absolute emissions (gross emissions) will be quantified and included in the footprint if the emissions are greater than positive or negative 20,000 tonnes CO_2e/year (as defined in section 5). Absolute emissions concern a project's emissions during a typical year of operation i.e. not including commissioning or unplanned shutdowns. The appraisal team calculates and reports the project's absolute emissions even though EIB is only contributing a part of the total financing plan.

The absolute emissions should be calculated based on project-specific data. Where project-specific data is not available, it is good practice to use default factors based on sector specific activity data and through the application of documented emission factors. A compilation of default methodologies by sector is attached as Annex 1 to this note for guidance. Emissions will be estimated by multiplying activity data, such as the volume of fuel used or product produced, by a project-specific or an industry default emission factor.

The default methodologies are separated into combustion emissions and those emissions arising from processes other than combustion, normally the result of a chemical reaction during a production process or because of a processing stream. Emissions may also be fugitive where a leak or vent of a GHG occurs from some part of the project installation such as a valve or transformer.

A combination of methodologies can be used where appropriate. For example a project which has:

- onsite energy generation through fuel combustion e.g. generators, boilers or kilns and;
- uses purchased electricity from the national grid and;
- has an associated process type emission e.g. cement production

may use a combination of Annex 1 methodologies to calculate absolute emissions for the project as follows:

1A Stationary fossil fuel combustion + 1E Purchased electricity + 6 Cement (clinker) production

8.3 Baseline emissions (Be)

Measuring baseline emissions is a useful complement to absolute emissions. It provides a credible alternative scenario "without" the project, against which the "with" project scenario[5] can be compared – giving an indication of how, measured in GHG metrics, the proposed project performs. However, the "without" project scenario, or baseline, is clearly theoretical and hence incorporates an additional level of uncertainty beyond those involved in estimating absolute emissions.

The project baseline scenario (or "without" project scenario) is defined as the <u>expected</u> alternative means to meet the output supplied by the proposed project[6].

[5] In this case, "with" project scenario is the expected emissions from the project.

[6] In general, the baseline scenario is based on a combination of best available technology and least cost principles. In some circumstances, one could also assess alternative scenarios in which prices or regulatory requirements are used to determine options or constrain demand to existing supply. This is relevant where current pricing is clearly inefficient or when regulatory requirements impose specific conditions on all installations.

The baseline scenario must therefore propose the likely alternative to the proposed project which (i) in technical terms can meet required output; and (ii) is credible in terms of economic and regulatory requirements.[7]

The first step is to propose a baseline scenario that meets demand in technical terms. Three examples – expanded in detail below – are:

- Example 1: a new conventional thermal power plant is introduced into an electricity network with zero demand growth; without the new plant, the existing power plants connected to the grid ('the operating margin') would have continued to meet demand. By contrast, if demand is growing sharply, supply would have been provided in part by existing capacity and in part by alternative new generation capacity ('build margin') and/or in part through a regional grid interconnection.
- Example 2: modernising a cement plant. Without the project, alternative regional plants both existing and new build or modernised would have met demand.

In a second step, it is necessary to check that the proposed scenario is credible. The baseline scenario should meet three conditions:

- The socio-economic test: in general terms, the baseline scenario should show an economic rate of return above the social economic discount rate.[8] In the specific case that external costs are internalised through public policy (carbon tax; emissions trading scheme etc.) the financial rate of return of the baseline scenario should not differ significantly from the ERR;
- The legal requirement test: the baseline alternative could not fail to comply with binding legal requirements (either technology, safety or performance standards, including portfolio standards e.g. 10% biofuels in fuel mix);
- The life-expired asset test: the baseline alternative could not assume to continue using existing assets beyond their economic life (based on regular operations and maintenance) at least not without appropriate deterioration in quality of service.

This baseline definition differs in general from an evaluation of emissions 'before and after' the investment.

- By definition, emissions prior to developing on a greenfield site are zero. Hence, applying a simple ''before and after'' approach gives rise to a zero baseline. By contrast, the baseline scenario defined above, i.e. without project scenario, places no weight on whether development is greenfield, brownfield or partial replacement – the key issue is how the projected demand could otherwise have been met, which is not addressed in the 'before and after' scenario.
- If the project is designed to replace a life-expired asset, a ''before and after'' approach would use previous emissions as the baseline. However, this approach would lack credibility in many cases if, for example, the existing asset is life expired and could not have continued over the course of the asset life of the proposed project.

[7] A baseline that is consistent with the best economic alternative is not necessarily identical to it. The best economic alternative is defined as the most competitive and viable alternative investment to which the project is compared; whereas the baseline for the carbon footprint is the most likely outcome in the absence of the project, e.g. meeting demand through a combination of existing and new infrastructure. The baseline is expected to include the best economic alternative as a component of the emissions calculation.

[8] Note that ERRs are not always calculated, for example in case of asset renewal in rail/urban.

8.4 Relative emissions (Re)

Relevant emissions concern a project's emissions from a typical year of operation i.e. not including commissioning or unplanned shutdowns. The appraisal team calculates and reports the project's relative emissions even though EIB is only contributing a part of the total financing plan. Relative emissions are defined simply as:

Relative Emissions = "With" Project Emissions (Wp) – "Without" Project Emissions, or Baseline Emissions (Be)

(Re = Wp – Be)

The "with" project emissions must have the same boundary as the "without" project emissions in terms of scope, but can differ from the boundary used for absolute emissions, because the boundary is sometimes extended for relative emissions, e.g. in the case of networks (see boundary conditions in section 7 of the methodology above).

Relative emissions may be positive or negative: where negative, the project is expected to result in a savings in GHG emissions relative to the baseline and vice versa (subject to the general caveats surrounding the carbon footprint methodologies). Expressing a project's relative carbon footprint is one way of evaluating the impact of a project in emissions terms since it provides a context to the absolute emissions of the project, i.e. whether the project reduces or increases GHG emissions overall. This can then be used as an indicator, along with others, of the environmental performance of the project.

The examples below present the approach the EIB typically takes for carbon footprinting in three sectors: energy, industry and transport. All emissions are calculated for a typical year of operation during the economic lifespan of the project.

Example 1: A Gas-fired Combined Heat and Power plant (CHP) in Germany

<u>Absolute emissions</u>

The CHP plant is expected to generate approximately 800 GWh per annum. The resulting CO_2 emissions are estimated to be 0.225 kg/kWh, based on plant efficiency of 90% and the default emission factor for natural gas 56,200 kg CO_{2e}/TJ (including the correction factor for unoxidised carbon). Therefore the absolute emissions are:

Ab = (800 * 0.225 * 1,000,000) / 1,000 = **179,840 tons CO_{2e}/year**

<u>Baseline emissions</u>

In Germany, the emission factor for electricity consumption for utilities (MV grid) would be 0.366 kg CO_2/kWh.

Therefore:

Be = (800 * 0.366 * 1,000,000) / 1,000 = **292,800 tons CO_2e/year**

<u>Relative emissions</u>

In this example, the "with" project, emissions are equivalent to the calculation of absolute emissions, therefore:

Re = 179,840 – 292,800 = **minus 112,960 tons CO_2e/year**

Overall, the project, compared to the baseline scenario is expected to result in reduction in emissions of 112,960 tons CO_2 per annum due to the displacement of less efficient firm generation that is currently produced in the German grid.

Example 2: Modernisation of a Cement Plant in Italy

Absolute emissions
The cement plant substitutes in part clinker with slag from a nearby steel plant. The plant produces 1,200,000 tons of cement using 800,000 tons of clinker. The conversion factor for clinker production is 0.83 t CO_{2e}/t clinker. The plant also purchases electricity at 40 kWh/t cement produced converted to CO_2e using the Italian emission factor for electricity consumption for heavy industry (HV grid) of 0.257 kg CO_2/kWh.

Ab = (800,000 * 0.83) + (1,200,000 * 40 * 0.257 / 1,000) = **676,318 tons CO_2e/year**

Baseline emissions
Cement markets are predominantly regional, so the baseline reflects how cement production would be met using local plants. Assuming a ton of cement produced locally requires 0.889 tons of clinker, in order to produce the same amount of cement, 1,066,800 tons of clinker would be required. Purchased electricity is 50 kWh/t cement produced.

Be = (1,066,800 * 0.83) + (1,200,000 * 50 * 0.257 * 1000) = **900,841 tons CO_2e/year**

Relative emissions

Re = 676,318 – 900,841 = **minus 224,523 tons CO_2e/year**

Overall, the project, compared to the baseline scenario is expected to result in a reduction in emissions of 224,523 tons CO_{2e}/year. This is due to the part replacement of high CO_2 emitting clinker with slag from a neighbouring steel plant.

Example 3: Rehabilitation of a Railway Line in Poland

For rail infrastructure projects when a cost benefit analysis (CBA) is prepared with the Bank's proprietary excel based model, RAILMOD, then the carbon footprint is calculated with this model.

Absolute emissions
The project concerns the modernization of an existing twin track line in Poland for about 140 km. The line usage at opening is forecast to be about 60 electric powered trains per day. With 365 days in a year, this means 21,900 trains per year. The absolute emissions are calculated from a multiplication of the assumed power consumption, in this case 10.5 kWh per train km, the Polish emission factor for electricity consumption for railways (HV grid) of 579 g per kWh, the total train km per year and the assumed growth in train km over time, including for demand induction as a result of the project (EIB Services assumption based on national plans).

The absolute forecast based on these inputs comes to 18,648 tons per average operating year.

Baseline emissions
The usage of the line without modernization is about 56 electric powered trains per day. Using the assumptions above for the emissions calculation (10.5 kWh per train km and an emission factor for electricity of 579 gCO_2/kWh), the emissions for the existing twin track of 140 km is estimated to be 17,405 tons per average operating year.

The opening year passenger demand is assumed to come from two sources: (i) diverted from existing modes, namely the existing rail service as well as the main competitors here, private cars and buses and (ii) induced rail trips. In this example, the vast majority of opening year passenger traffic is forecast to be diverted from existing rail. A portion is also diverted from buses (4%) and cars (4%) and a portion is induced (about 10% on average). The passenger demand diverted from other modes is captured in the baseline emissions (i.e. in the baseline, a portion of traffic is assumed to be travelling by car/bus at a higher emission rate per passenger km).

The baseline forecast comes to 22,800 tonnes per average operating year.

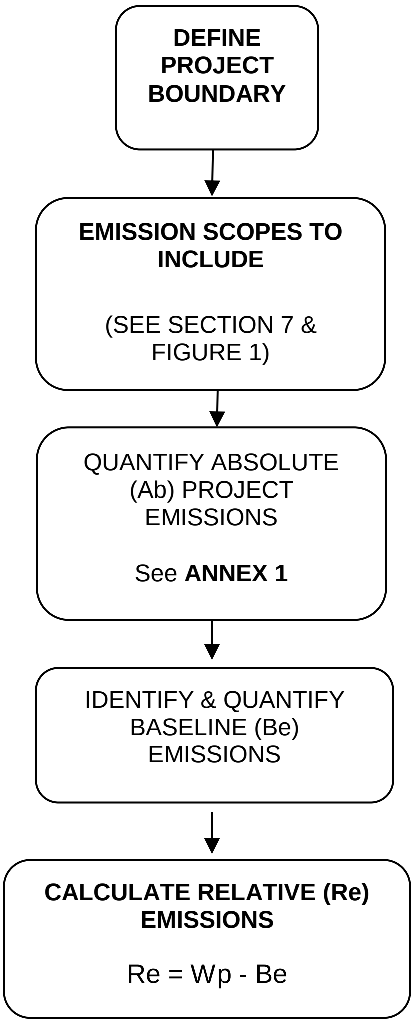
Relative emissions
In this example, the "with" project emissions are equivalent to the calculation of absolute emissions, therefore:

Re = 18,648 – 22,800 = **minus 4,152 tons CO_2e/year**

9. Quantification process and methodologies

Figure 2 illustrates the overall series of activities to quantify the EIB carbon footprint for investment projects and the associated relative emissions compared to the baseline.

Figure 2: Project carbon footprint calculation flow



***NB** If a project's absolute emissions or its relative emissions variation from the baseline scenario reach the thresholds shown, it is included in the EIB Carbon Footprint. If is below this threshold, it is not included:*

≥+ or (-) 20,000 tonnes CO_2e/year ABSOLUTE threshold for inclusion
≥+ or (-) 20,000 tonnes CO_2e/year RELATIVE threshold for inclusion

9.1 The assessment of intermediated projects

The quantification of the carbon footprint for multi-investment intermediated projects (e.g. Multi-beneficiary intermediated loans, Framework Loans, Global Loans, Equity and Debt Funds) poses challenges. Information on the large number of sub-projects financed under these operations is highly limited, which does not permit a reasonable assessment of the GHG emissions from the sub-projects, especially smaller ones and those targeting SMEs. Intermediated lending through these types of vehicles is not currently included in the carbon footprint, except for large allocations of Framework Loans that are subject to individual appraisal and submission to the Board. These should be treated as Investment Loans and included in the footprint if emissions cross the thresholds, in the year the allocation is approved by the Bank.

ANNEX 1: DEFAULT EMISSIONS CALCULATION METHODOLOGIES

<table>
<tr><th>Method #</th><th>Sector & GHG</th><th>Calculation Input Data Requirements (i) (ii) etc.</th><th>Calculation Method</th></tr>
<tr><td>1A</td><td>Stationary fossil fuel combustion

CO_2e</td><td>(i) Annual fuel use in energy units (e.g. TJ), volume or mass units

(ii) Default emission factor (see table A1.1)</td><td>CO_2e (t) = Fuel energy use * Emissions Factor</td></tr>
<tr><td>1B</td><td>Stationary fossil fuel combustion

N_2O</td><td>(i) Annual fuel energy input (derive from data above)

(ii) Default emission factor (see table A1.1)</td><td>N_2O (t) = Fuel energy input * emission factor</td></tr>
<tr><td>1C</td><td>Stationary biomass fuel combustion[9]

CH_4 and N_2O</td><td>(i) Fuel energy input (derive from data above)

(ii) Default emission factors (CH_4 and N_2O expressed as CO_2e):

<table>
<tr><th></th><th>t CO_2e/TJ</th></tr>
<tr><td>Energy/Manufacturing</td><td></td></tr>
<tr><td>- Gaseous</td><td>0.0545</td></tr>
<tr><td>- Liquid</td><td>0.243</td></tr>
<tr><td>- Solid</td><td>1.9</td></tr>
<tr><td>- Municipal waste</td><td>1.9</td></tr>
<tr><td>- Unknown</td><td>1.37</td></tr>
<tr><td>Commercial/Residential</td><td></td></tr>
<tr><td>- Gaseous</td><td>9.46</td></tr>
<tr><td>- Liquid</td><td>0.439</td></tr>
<tr><td>- Solid</td><td>0.1665</td></tr>
<tr><td>- Municipal waste</td><td>9.46</td></tr>
<tr><td>- Unknown</td><td>3.33</td></tr>
</table>

(iii) In line with international and EU common practice, CO_2 releases from the combustion of biomass is accounted for as 0 (see footnote 4 earlier in the text).

(iv) Emissions associated to the production for agricultural biomass fuel and processing of agricultural and forest biomass are including where significant:

• Fertilisers for purpose grown energy crops (N_2O); Fuel oil consumed to run machinery at farm level; chipping; drying, torrefaction and peletising of solid biomass (CO_2), and long-distance transportation (CO_2); factors on a case by case basis</td><td>CH_4 (t) = Fuel energy input * emission factor

N_2O (t) = Fuel energy input * emission factor

Conversion factors to convert to CO_2e see table A1.9</td></tr>
<tr><td>1D</td><td>Cogeneration Combined Heat and Power (CHP)

CO_2e</td><td>Direct emissions from fuel combustion to follow methodology 1A and 1C, as applicable, above.</td><td></td></tr>
<tr><td>1E</td><td>Purchased electricity

CO_2e</td><td>(i) Energy Purchased for use in project activities

(ii) Country specific emissions factor (see table A1.3) for electricity consumption or</td><td>CO_2 (t) = Energy use * Country Specific Emissions Factor for Electricity Consumption</td></tr>
</table>

[9] Note that emissions from the combustion of biomass in e.g. power generation, industry, waste treatment or transport fuels in considered zero, as explained previously (see footnote 4 and associated explanation).

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		in special cases, such as electricity for pumped storage, the appropriate combination of marginal plants.	
1F	**Renewable energy** **CO_2e**	(i) Zero or minor absolute emissions except for hydropower with large reservoir storage capacity (see hydro reservoir emissions table A1.8). (ii) Renewable energy is assumed to displace (at least in part) fossil fuels (see electricity generation baseline assumptions Annex 2).	CO_2 (t) = Energy generated * Country Specific Emissions Factor for Electricity Combined Margin
1G	**Stationary combustion of waste type fuels** **CO_2e**	(i) Annual fuel use (ii) Default emission factor (see table A1.1) (iii) Zero or minor absolute emissions for organic portion of waste fuels.	CO_2 (t) = Fuel use * Fuel Emissions Factor
2	**Oil/gas production, processing, storage and transport** **CO_2, CH_4**	All combustion including flare emissions may be derived from 1a above. Emissions of N_2O are not considered significant in petroleum refining and gas processing (IPIECA GHG Guidelines, 2003). Compressor emissions are calculated from fuel combustion as above or from purchased energy. **Fugitive emissions** Fugitive emissions are leaks from components such as pipe connections, valves, rotating shafts etc. The calculation of fugitive emissions is insensitive to the number of components and the benefit to be derived from identifying the precise number of components is negligible. A coarse estimate of component numbers, focusing on large potential sources such as compressors, is recommended (i) Facility production of transport system flow rates (ii) Emissions factor (see tables A1.2) (iii) API compendium lists a default approach as being to assume that storage tank working and breathing loss emissions are negligible for CO_2 and CH_4. **Storage tank fugitive emissions** (i) API compendium lists a default approach as being to assume that tank working and breathing loss emissions are negligible for CO_2 and CH_4. **Catalytic Regeneration** (i) Rated throughput of the unit (ii) Benchmark energy consumption for the unit from and verified feed or product density data as appropriate in kWh fuel (net)/t throughput (iii) Catalytic cracking unit factor (pet coke) = 0.358 kg CO_2/kWh*	Fugitive emissions and venting t CO_2/yr = Volume or mass of ref. gas * Emissions Factor ref. gas Fugitive CH_4= emissions factor * production Cat Regen kg CO_2= throughput kWh x 0.358 Hydrogen Gen. CO_2 (t) = Hydrogen feed x 2.19 Note: Detailed emissions factors are known to show a wide variation.

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		<u>Hydrogen generation</u> (i) Hydrogen feed processed (conservatively based on ethane) (ii) Hydrogen gen. emissions factor 2.19 t CO_2/t feed * *EU ETS 2007 **<u>LNG Production</u>** Liquefaction of natural gas utilises part of the supply of gas to the plant for energy consumption: 7.7 t CO2/TJ of LNG **<u>LNG Vaporisation</u>** There are two common methods of vaporisation. The first is to use heated water baths in a submerged combustion vaporisation process. CO2 emissions arise from the combustion of fuel gas. (i) LNG design through put (ii) Load factor (iii) Apply 00.98 t CO2/TJ of LNG. The second process is an open rack sea water system which involves no combustion but may use significant amounts of imported electricity to power water pumps. Emissions from storage of LNG are not considered material. *(LNG emission factor for liquefaction is based on emissions for LNG liquefaction terminals in Egypt. The value for regasification is based on a regasification plant in Greece.)* **<u>LNG Transportation</u>** Transport of natural gas utilises LNG boil-off for fuel, on-board electricity generation, refrigeration, and gas compression. The energy intensity of LNG shipping is: 1.13 t CO2/TJ for a shipping transport duration of 100 hrs.	SCV t CO_2= tonnes LNG design capacity * load % * 0.393 1 t LNG = 0.0545 TJ 1 t LNG = 15.14 MWh
3	**Coal mining** **CH_4**	(i) Annual mass of coal mined (ii) Default emission rates: • underground coal: 10 – 25 m3 CH_4 / t coal • surface-mined coal: 0.3 – 2 m3 CH_4 / t coal • underground, post-mining: 0.9 - 4 m3 CH_4 / t coal • surface-mined, post-mining: 0 – 0.2 m3 CH_4 / t coal	CH_4 (t) = Coal mined (t) * (emission per tonne mined + emission per tonne post-mining) * 0.00067 Conversion factors to convert to CO_2e see table A1.9
4	**Electricity, Gas and Heat Transmission & Distribution** **CO_2 and SF_6**	Scope 1 direct emissions and scope 2 electricity consumption and fugitive losses from equipment and the network, over an average year. (i) Distribution losses for the part of the network (energy) affected the project	GHG emissions for electricity transmission and distribution losses = Energy loss * Country specific emissions factor for electricity consumption.

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		(ii) Electricity consumption based on electricity emission factor for country (table A1.3) (iii) Total quantity of SF_6 in switchgear and circuit breakers (iv) Switchgear and circuit breakers: SF6 leakage rate: total life cycle: 0.4%, only operation phase: 0.13% (v) Fugitive emissions (see methodology 2) If GHG emissions are only quantifiable for the whole network, then a pro-rata proportion must be calculated for the extension/rehabilitation only. All network losses associated with incremental supply are attributed to network extensions (see Annex 2). If the secondary effects of the project on GHG emissions are significant and there is no risk of double counting, these effects are included as emissions outside the project boundary for the assessment of baseline and relative emissions. Examples include the impact of redispatch of existing generation connected to an electricity network, de-bottlenecking existing RES generation, or heat fuel switching of customers connected to gas or district heating networks. Due to the risk of double counting, the impact or future new infrastructure connected to the network (e.g. new power or heat plants, industrial facilities or buildings) should not be included.	Assume High Voltage losses of 2%, Medium Voltage losses of 4% and Low Voltage losses of 7% (non-cumulative). For electricity, the baseline without the project is to meet market demand assuming increased network losses. In such cases, Baseline losses are assumed to be equal to: Current % of network losses x (1 + % demand growth). SF_6 (CO2 t/y) = SF_6 project inventory(t) * SF_6 leakage rate * SF_6/CO_2 emissions factor Conversion factors to convert to CO_2e see table A1.9.
5	**Flue gas desulphurisation (limestone based)** **CO_2**	(i) Annual usage of limestone (t) (ii) calcium carbonate content (% wt) (iii) magnesium carbonate content (% wt)	CO_2 (t) = Annual usage (t) x [(% $CaCO_3$ * 12/100) + (% MgCO3 * 12/84)] * 3.664
6	**Industrial processes** **All GHGs**	The main emission sources from industrial processes are those which chemically or physically transform materials. Industrial processes include: • Metal Industry processes, such as aluminium, iron, steel, lead, copper and zinc production. • Chemical industry processes, such as the production of nitric acid, ammonia, adipic acid production • Mineral industry processes, such as cement, lime, glass, soda ash production • Other industry processes such as pulp and paper production The footprint calculation will include: (i) Emissions from 1A Stationary Combustion of Fossil Fuels (ii) Emissions from 1E purchased electricity (iii) Plant specific process emissions Plant-specific process emissions are those produced for industrial activities not related to energy.	If plant-level information is not available, use 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 3 for default factors available on PJ Intranet.

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
7	**Waste Water & Sludge Treatment** **CO_2, CH_4, N_2O**	Significant CH_4 emissions from wastewater treatment (WWT) only arise from the anaerobic part of the process. Sludge disposal (e.g. landfill, use in agriculture, incineration) may be also responsible for CH_4 emissions. Collection of wastewater in underground sewers are not a significant source of CH_4 emissions. For cases where no data is available and to be able to make a first estimation, a range of emissions factors is given in the right column. These factors depend upon the waste water and sludge treatment method. They have been calculated by the EIB based on the IPCC 2006 Good Practice Guide. When more data is available, EIB's Water Division calculates the emissions using a tool based on the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, which evaluates the CO_2e (t/y) produced by the project and by the baseline scenario. The tool can also be used for other water projects such as wastewater collection and drinking water treatment and supply. The tool calculates with accuracy the emissions in CO_2e (t/y) produced in the wastewater treatment process (CH_4, N_2O and CO_2) and the emissions in CO_2e (t/y) produced by the final disposal of the sludge (CH_4). The tool enables the expert to introduce full process data about the collection and treatment, industrial contamination, methane recovery, sludge treatment etc. of the treatment facility.	1. Waste water treatment under anaerobic conditions (e.g. septic tank) CO_2e (t/y) = Pop. Eq. * 0.21 2. Aerobic wastewater treatment without anaerobic digestion of the sludge. Sludge disposal on land-fill CO_2e (t/y) = Pop. Eq. * 0.10 3. Aerobic wastewater treatment, with anaerobic digestion of the sludge. Sludge disposal on land-fill CO_2e (t/y) = Pop. Eq. * 0.06 4. Aerobic wastewater treatment, with anaerobic digestion of the sludge. Sludge disposal on incineration CO_2e (t/y) = Pop. Eq. * 0.04 5. Aerobic wastewater treatment, with enhanced anaerobic digestion of the sludge. Sludge disposal on industrial use (e.g. cement) CO_2e (t/y) = Pop. Eq. * 0.02
8	**Road transport** **CO_2**	Proprietary model ERIAM is used. This takes project input data in the form of traffic data and costs data and calculates the emissions without the project, emissions with project for third party use of the project infrastructure in the form of existing and induced traffic indirect emissions. Induced traffic is determined by the analyst on a case by case basis according to circumstances of the project, usually by applying an appropriate elasticity to the percentage change in expected time savings in the opening year. The model has an assumed set of relationships relating to speed and fuel use, speed and traffic flow and fuel use and GHG emissions. The sector expert can select the relative ratio of diesel and gasoline vehicles in use and the type of vehicles considered are light vehicle diesel and gasoline and heavy goods vehicle diesel. Emissions factors for fuel types can be entered by the user into the model. Emission factors may be found in table A1.7, but can also be included based on specific promotor information or sector expertise. Emissions from the project construction phase are not included.	ERIAM.xls

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
9	**Rail transport** **CO_2**	Proprietary model RAILMOD is used. This takes project input data on rail line lengths and uses and calculates the avoided emissions, absolute emissions and baseline emissions. Alternative modes that are considered are rail, high speed rail, car (truck for freight), bus and plane. Modal shift is accounted for. Emissions factors for fuel types can be entered by the user into the model. Emission factors may be found in table A1.7, but can also be included based on specific promotor information or sector expertise. If the project is a rolling stock replacement, the project boundary is the fleet being replaced and the operation to which it is dedicated. Absolute emissions are those related to the operation carried out by these vehicles: the total yearly production in train-km for the replaced fleet is calculated. Based on this, on the average consumption (per car-km or train-km) of fossil fuel or of electric energy, and on the CO_2 emission factor (grams of CO_2 per litre of fossil fuel or per kWhr), the total fleet emissions per year are calculated (Scope 1 or 2 emissions). For baseline emissions either the replaced fleet is taken as a conservative assumption (if the old fleet can still be legally operated) or, in case sufficient information is available, any modal shift and induced traffic is calculated.	RAILMOD.xls
10	**Urban transport** **CO_2**	Proprietary model URBMOD is used to calculate emissions. This takes project input data from the promoter's traffic model and calculates absolute, baseline and relative emissions. Absolute emissions are calculated as those stemming from the project's operation and are therefore always identical to the without project scenario. Baseline emissions are those related to the modal shift generated by the project, that is the savings in emissions stemming from the reduction of the mileage of competing modes resulting from the shift in demand to the project. Reported emissions are the average over the entire Project's economic life. URBMOD is conceived to appraise different urban transport modes including electricity based systems such as suburban railways, metro and tramway lines, light rail systems and trolley/electric buses as well as standard buses. Alternative modes to public transport that can be modelled with URBMOD are cars and mopeds. Emission factors for buses, cars and mopeds are based on COPERT/TREMOVE values for the urban cycle and are country specific. The user can enter specific emission factors into the model and overwrite default values from COPERT/TREMOVE. Emission factors may be found in table A1.7, but can also be included based on specific promotor information or sector expertise. For electricity based systems, the uses enters a specific consumption rate in the model (kWh/km) which is then converted into GHG emissions (gCO_2/kWh) through average electricity emission factors reported in table A1.3. There is no default	MOB/PTR proprietary model (URBMOD) which uses distance travelled and an emissions factor for the mode of transport.

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		value for electricity consumption in urban public transport. URBMOD is typically used for new infrastructure with significant impacts on service supply and demand. It is not used for asset renewal with marginal impact on supply and demand, for which a demand estimate based on a traffic model is normally not available. For this type of operations where modal shift is limited, absolute emissions are calculated as those stemming from the project's operation and are therefore always identical to the with project scenario. Baseline emissions are either calculated in relation to a long-term do-nothing scenario with dismissal of existing assets and modal shift to other competing modes or a short-term without project scenario that is equivalent to the observed situation. In this latter case, absolute and baseline emissions may be very similar, in particular when no technological or behavioural change is anticipated.	
11	**Other transport** **CO_2**	Vessels If the project is financing a new fleet of vessels, the project boundary is the financed vessels and the expected operations. Absolute emissions of a new fleet/vessel are the average annual emissions of the project vessel(s). This estimation is based on expected annual fuel use per fuel type of the project vessel(s) (if available otherwise averages will be used) and standard fuel emission factors. No absolute emissions are calculated for retrofit operations. Relative emissions are calculated as the average per unit emissions savings between the project and the without project scenario over the economic life of the project, multiplied with the traffic in the project scenario. In competitive markets, the relative emissions are expected to be limited. Ports A detailed methodology for the calculation of the carbon footprint of a port project can be found in ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY. Air If the project is financing new aircraft, the project boundary is the financed aircraft and the operation to which they are dedicated. Absolute emissions are those related to the operation of these vehicles: the total yearly production in km is estimated based on the routes taken and number of trips per annum. Using this figure and the average occupancy of the plane in number of passengers, the emissions can be expressed by multiplying by the efficiency factor of the aircraft – expressed in g CO_2/ pax*km. Airports A detailed methodology for the calculation of the carbon footprint of an airport can be found in ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY.	Absolute emissions = project fleet energy consumption per fuel type* emission factors Relative emissions = (average per unit emissions without project - average per unit emissions with project)*project traffic

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
12	**Reservoirs** **CO_2, CH_4**	(i) Flooded total surface area (ii) CO_2 diffusive emissions factor (table A1.8) (iii) CH_4 diffusive emissions factor (table A1.8) (iv) CH_4 bubbles emissions factor (table A1.8) The large uncertainties associated with IPCC emissions factors should be noted.	CO_2 = 365 * ii * i CH_4 = (365 * iii * I) + (365 * iv*i)) Conversion factors to convert to CO_2e see table A1.9
13	**Waste treatment facilities**	Absolute process emissions are calculated using default emission factors (IPCC 2006). Baseline scenario for waste treatment facilities in the EU: Basic MBT facility with separation of large bulky fractions and subsequent aerobic stabilisation of the biodegradable waste fractions, landfill disposal of all residues with insignificant GHG emissions from residue disposal. Baseline scenario for waste treatment facilities outside the EU: An engineered landfill with minimum landfill gas collection and flaring.	Composting: 4 kg CH_4 per ton waste 0.24 kg N_2O per ton waste Anaerobic digestion: 0.8 kg CH_4 per ton waste Waste incineration: 91.7 t CO_2 / TJ fossil municipal solid waste input 143.0 t CO_2 / TJ industrial waste input or 91.7 t CO_2 / TJ fossil share of input if characteristics are similar to MSW. 0.03 t CH_4 / TJ fossil municipal solid waste input 0.004 t N_2O / TJ fossil municipal solid waste input Relevant CO_2 default emission factor for auxiliary fuel used
14	**Municipal Solid Waste Landfill** **CH_4**	CH_4 emissions are calculated using the IPCC 1996 Default Methodology Tier 1. This evaluates the total potential yield of methane from the waste deposited, expressed as an average annual emission. The following data are required: (i) Annualised mass of MSW to be deposited, MSWT (t/y) (ii) Methane Correction Factor (MCF) – reflecting the nature of the waste disposal practices and facility type. Recommended values are: a. Managed (anaerobic) (i.e controlled waste placement, fire control, and including some of the following: cover material, mechanical compacting or levelling): MCF = 1 b. Managed (semi-aerobic) (i.e. controlled placement and all these structures for introducing air to waste layer: permeable cover material; leachate drainage system; regulating pondage; and gas ventilation system): MCF = 0.5, c. Unmanaged- deep (> 5m waste): MCF = 0.8, d. Unmanaged- shallow (< 5m waste): MCF = 0.4, e. Uncategorised (default): MCF = 0.6	CH_4 (t/y) = [MSWT x L0 - R] x [1 - OX] where L0, the methane generation potential in t CH_4 / t MSWT is calculated as: L0 = MCF x DOC x DOCF x F x (16/12) The CO_2 fraction of landfill gas and CO_2 from landfill gas flaring is assumed to be GHG neutral as part of the biological cycle.

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		(iii) Degradable Organic Carbon (DOC) – fraction of MSW that is degradable carbon. Default values are: Food waste (0.15), Garden (0.2), Paper (0.4), Wood and straw (0.43), Textiles (0.24), Disposable nappies (0.24), Sewage sludge (0.05), Rubber (0.39), Bulk MSW (0.18) and Industrial waste (0.15). (iv) Fraction of DOC dissimilated (DOCF) - i.e. the fraction that is ultimately degraded and released: default = 0.5. (v) Fraction by volume of CH_4 in landfill gas (vi) Mass of CH4 recovered per year for energy use or flaring, R (t/y) (vii) Fraction of CH_4 released that is oxidised below surface within the site, OX. Default is OX = 0.1 for well-managed sites, otherwise 0.	
15	**Refrigeration / Air conditioning / Insulation Industry HFCs**	A variety of industrial processes involve refrigeration and air conditioning and thus indirectly employ HFCs. It is recommended that only where the manufacture and use of such equipment is a major aspect of a project should an assessment be undertaken. In such cases the user is referred to IPCC 1996 Reference Manual for recommended sector -specific calculation methods. See table A1.9 for GWP of HFCs.	
16	**Semiconductor and LCD manufacturing - construction and operation wafer plants**	Electronics manufacturing processes utilise poly fluorinated compounds (PFCs) for plasma etching, intricate patterns, cleaning reactor chambers, and temperature control. The gases include CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, and SF_6. In addition, more than 20 different liquid PFCs are marketed, often as mixtures of fully fluorinated compounds to the electronic sector. Evaporative losses contribute to the total FC emissions.	Gas in to the process chamber, gas out of the process chamber and % of the gas out that is being retained by abatement systems.
17	**Building Refurbishment** **CO_2**	(i) Electric Energy Purchased for use in the buildings (ii) Thermal Energy/ fuel purchased for use in the buildings (iii) Project specific heat emissions factor (District Heating, fossil fuel boilers (building or apartment level) (iv) Country specific emission factors (see table A1.3)	CO_2e (t) = electric energy use * country specific emissions factor for electricity consumption + heat energy use * project specific heat emission factor
18	**Forestry** **CO_2, N_2O**	A detailed methodology for the calculation of the carbon footprint of a forestry project can be found in ANNEX 3: FORESTRY CARBON FOOTPRINT CALCULATION METHODOLOGY.	
19	**Installation, upgrading and/or expansion of fixed telecommunications network**	1E Purchased electricity for the full network (core, backhaul, access, Network Operation Center, etc…). 1E Purchased electricity of the CPE´s (if included in the project scope). For new network roll-out, baseline should refer to state of the art equipment.	

Method #	Sector & GHG	Calculation Input Data Requirements (i) (ii) etc.	Calculation Method
		If the project includes swap-out of existing equipment, previous technological generation should be used for baseline to allow capturing the increase in energy efficiency.	
20	**Installation, upgrading and/or expansion of mobile telecommunications network**	1E Purchased electricity Where significant diesel generation capacity is installed for the base stations then also use 1A Stationary combustion Power consumption of mobile handsets is not to be included. For new network roll-out, baseline should refer to state of the art equipment. If the project includes swap-out of existing equipment, previous technological generation should be used for baseline to allow capturing the increase in energy efficiency.	
21	**Installation, upgrading and/or expansion of submarine cables, satellite networks and infrastructure or data centers**	1E Purchased electricity	

Table A1.1: Default Emission Factors

TJ factors from 2006 IPCC Guidelines for National Greenhouse Gas Inventories these factors assume no unoxidized carbon. To account for unoxidized carbon, IPCC suggests multiplying by these default factors: solid = 0.98, liquid = 0.99, and gas = 0.995. Other factors are from WRI/WBCSD GHG protocol.

GASEOUS FOSSIL FUELS

Fuel Name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unox. carbon
Natural gas	1	Cubic metre (m^3)	1.9	0.0	0.0	1.9	1.9
Natural gas	1	TJ	56,100	1.0	0.1	56,155	55,874
Refinery gas	1	metric tonne (t)	2,851	0.0	0.0	2,851	2,837
Refinery gas	1	TJ	57,600	1.0	0.1	57,655	57,367
Liquefied Petroleum Gases	1	litres (l)	1.6	0.0	0.0	1.6	1.6
Liquefied Petroleum Gases	1	TJ	63,100	1.0	0.1	63,155	62,839
Blast furnace gas	1	metric tonne (t)	642	0.0	0.0	642	639
Blast furnace gas	1	TJ	260,000	1.0	0.1	260,054	258,754
Coke oven gas	1	metric tonne (t)	1,718	0.0	0.0	1,718	1,709
Coke oven gas	1	TJ	44,400	1.0	0.1	44,454	44,232
Oxygen steel furnace gas	1	metric tonne (t)	1,284	0.0	0.0	1,284	1,278

LIQUID FOSSIL FUELS

Fuel Name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unox. carbon
Gas/Diesel oil	1	litres (l)	2.7	0.0	0.0	2.7	2.7
Gas/Diesel oil	1	TJ	74,100	3.0	0.6	74,343	73,600
Crude oil	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Crude oil	1	TJ	73,300	3.0	0.6	73,543	72,808
Refinery feedstocks	1	metric tonne (t)	3,152	0.1	0.0	3,155	3,123
Refinery feedstocks	1	TJ	73,300	3.0	0.6	73,543	72,808
Motor gasoline	1	litres (l)	2.3	0.0	0.0	2.3	2.3
Motor gasoline	1	TJ	69,300	3.0	0.6	69,543	68,848
Aviation/jet gasoline	1	litres (l)	2.2	0.0	0.0	2.2	2.2
Aviation/jet gasoline	1	TJ	700,000	3.0	0.6	700,243	693,241
Aviation/jet gasoline	1	metric tonne (t)	3,101	0.1	0.0	3,104	3,073
Jet kerosene	1	TJ	71,500	3.0	0.6	71,743	71,026
Naphtha	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Naphtha	1	TJ	73,300	3.0	0.6	73,543	72,808
Shale oil	1	litres (l)	2.8	0.0	0.0	2.8	2.8
Shale oil	1	TJ	73,300	3.0	0.6	73,543	72,808
Residual fuel oil / HFO	1	litres (l)	2.9	0.0	0.0	2.9	2.9
Residual fuel oil / HFO	1	TJ	77,400	3.0	0.6	77,643	76,867
Other kerosene	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Other kerosene	1	TJ	71,900	3.0	0.6	72,143	71,422

Table A1.1 (contd.) Default Emissions Factors

SOLID FOSSIL FUELS

Fuel Name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unox. carbon
Anthracite	1	metric tonne (t)	2,625	0.0	0.0	2,625	2,573
Anthracite	1	TJ	98,300	1.0	1.5	98,726	96,751
Bitumen	1	metric tonne (t)	3,244	0.1	0.0	3,247	3,182
Bitumen	1	TJ	80,700	3.0	0.6	80,943	79,324
Lignite	1	metric tonne (t)	1,202	0.0	0.0	1,202	1,178
Lignite	1	TJ	101,000	1.0	1.5	101,426	99,397
Other bituminous coal	1	metric tonne (t)	2,441	0.0	0.0	2,441	2,392
Other bituminous coal	1	TJ	94,600	1.0	1.5	95,026	93,125
Sub bituminous coal	1	metric tonne (t)	1,816	0.0	0.0	1,816	1,780
Sub bituminous coal	1	TJ	9,6100	1.0	1.5	10,036	9,835
Brown coal briquettes	1	metric tonne (t)	2,018	0.0	0.0	2,018	1,978
Brown coal briquettes	1	TJ	97,500	1.0	1.5	97,926	95,967
Peat	1	metric tonne (t)	1,034	0.1	0.0	1,037	1,016
Peat	1	TJ	106,000	10	1.4	106,651	104,518
Municipal waste (Non biomass fraction)	1	metric tonne (t)	917	0.3	0.0	925	907
Coking coal	1	metric tonne (t)	2,668	0.0	0.0	2,668	2,615
Coking coal	1	TJ	94,600	1.0	1.5	95,026	93,125
Petroleum coke	1	metric tonne (t)	3,169	0.1	0.0	3,172	3,109
Petroleum coke	1	TJ	97,500	3.0	0.6	97,743	95,788
Coke oven coke	1	metric tonne (t)	3,017	0.0	0.0	3,017	2,957
Coke oven coke	1	TJ	107,000	1.0	1.5	107,426	105,277

SOLID WASTE FUELS

Source: Factors are for non-biomass fractions. IPCC 2006 Stationary Combustion

Fuel Name	Amount of fuel	Units	kg CO_2
Municipal Solid Waste (non biomass fraction)	1	TJ	91,700
Municipal Solid Waste (non biomass fraction)	1	metric tonne	917
Industrial Wastes	1	TJ	143,000
Waste oils	1	TJ	73,300

Table A1.2
Default Fugitive Emissions Factors Oil and Gas Production, Storage and Transport

Production type	Emissions factor
Default fugitive methane emissions[10]	28 tonnes CO2e/tonne CH_4 20 kg CO_2e/Nm^3 484.1 tonnes CO_2e/TJ
Onshore gas production	2.601E-02 tonnes CH_4/scf 9.184E-01 tonnes CH_4/m
Offshore gas production	1.040E-02 tonnes CH_4/scf 3.673E-01 tonnes CH_4/m
Onshore oil production	2.346E-04 tonnes CH_4/bbl 1.476E-03 tonnes CH_4/m
Offshore oil production	9.386E-05 tonnes CH_4/bbl 5.903E-04 tonnes CH_4/m
Gas processing plants	2.922E-02 tonnes CH_4/scf 1.032E+00 tonnes CH_4/m
Gas storage stations	6.767E+02 tonnes CH_4/station
Gas transmission pipelines CH_4 from pipeline leaks CO_2 from oxidation CO_2 from pipeline leaks	Total CH_4 = 2.235 tonnes CH_4/km-yr Total CO_2 = 1.33^{E-1} tonnes /km-yr Total CO_2e = 62.580 tonnes CO_2e /km-yr
Gas distribution pipelines CH_4 from pipeline leaks CO_2 from oxidation CO_2 from pipeline leaks	Total CH_4 = 1.002 tonnes CH_4/km-yr Total CO_2 = 4.12^{E-1} tonnes /km-yr Total CO_2e = 28.056 tonnes CO_2e /km-yr
Crude transmission pipelines	Negligible CH_4 fugitive equipment leak emissions
Refineries	Negligible CH_4 fugitive equipment leak emissions
LNG vaporisation using combustion	Total t CO_2 = Design throughput tonnes * 0.0393

Source: API Compendium, 2009 - Compendium of Greenhouse Gas Emissions Methodologies for the oil and natural gas industry. https://www.api.org/~/media/files/ehs/climate-change/2009_ghg_compendium.ashx

[10] Relative methane density of 0.716 $kgCH_4$/Normal cubic metre (Nm^3) at a reference temperature of 0°C; based on average EU gross calorific value of 11.5 kWh/Nm3 [25/0], equivalent to an energy density of 57.84 MJ/kg CH_4 (from ENTSO-G 2018 TYNDP gas quality forecast for 2020; https://www.entsog.eu/sites/default/files/2019-02/entsog_tyndp_2018_GQO_0.pdf)

Table A1.3 Country Specific Electricity Emission Factors

- Table A1.3 provides five different values for national country electricity grids with **all figures expressed in grams CO_2 per kilowatt hour (tonnes CO_2 per GWh)**. The figures are based on the IFI Dataset of Default Grid Factors v.2.0 from July 2019, which was created by the IFI Technical Working Group on GHG Accounting. The IFI dataset can be found here. The calculation methodology for the dataset can be found here.

Table A1.3 includes the following information:

- The Combined Margin for intermittent electricity generation, which should be used to calculate the baseline emissions for intermittent electricity generation such as solar, wind and tidal electricity generation.
- The Combined Margin for firm electricity generation, which should be used to calculate the baseline emissions for firm electricity generation such as hydro, geothermal and conventional fossil fuel powered electricity generation, electricity consumption, and electricity savings from energy efficiency measures.
- The emission factors for electricity consumption, including network losses. These emission factors for electricity consumption are used solely as the reference value for the calculation of electricity consumption and for transmission and distribution (T&D) losses and should not be used for the calculation of emissions from electricity generation projects. Where actual T&D losses are known, these can be used instead, as long as the sources are well documented. Typical projects using low, medium and high voltage grids are as follows:

    - HV grid – high speed rail; heavy industry projects (e.g. mining, steel production)
    - MV grid – manufacturing plants; utilities
    - LV grid – commercial; residential projects

  For mobility projects, the following grid factors should be used:

    - Electric trains and conventional rail infrastructure projects:
        - >15 kV: HV grid
        - 3 kV: MV grid
    - High speed trains and high speed rail infrastructure: HV grid
    - Tram / metro / light-rail projects: MV grid
    - Electric vehicles (LDV / cars & vans, HDV / trucks and buses): LV grid
    - EV charging: LV grid (higher power charging likely to be MV grid – to be verified during appraisal)

Emission Factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country / Territory / Island	Combined Margin Intermittent Electricity Generation	Combined Margin Firm Electricity Generation/ Electricity Consumption	Electricity Consumption/ Network Losses HV Grid +2%	Electricity Consumption/ Network Losses MV Grid +4%	Electricity Consumption/ Network Losses LV Grid +7%
Afghanistan	300	206	210	214	220
Albania	16	43	44	45	46
Algeria	498	429	438	446	459
American Samoa (U.S.)	699	544	555	566	582
Andorra	16	43	44	45	46
Angola	613	426	434	443	455
Anguilla (U.K.)	680	493	503	513	528
Antigua and Barbuda	693	527	538	548	564
Argentina	497	350	357	364	375
Armenia	339	247	252	256	264
Aruba	664	450	459	468	482
Australia	646	412	420	428	440
Austria	173	134	136	139	143
Azerbaijan	488	411	419	427	439
Azores (Portugal)	658	433	442	450	463
Bahamas	669	462	471	480	494
Bahrain	662	475	484	494	508
Bangladesh	565	502	512	522	537
Barbados	684	502	512	522	537
Belarus	390	336	343	350	360
Belgium	227	165	169	172	177
Belize	461	304	310	316	326
Benin	705	624	636	649	667
Bermuda (U.K.)	636	374	382	389	400
Bhutan	16	43	44	45	46
Bolivia	529	409	417	425	438
Bosnia and Herzegovina	1231	864	881	898	924
Botswana	1480	1179	1203	1227	1262
Brazil	296	201	205	209	215
British Virgin Islands (U.K.)	667	456	466	475	488
Brunei	536	379	386	394	405
Bulgaria	813	547	558	569	585
Burkina Faso	734	636	648	661	680
Burundi	465	316	323	329	339
Cambodia	820	580	592	604	621
Cameroon	397	275	281	286	294
Canada	286	231	236	241	248
Canary Islands (Spain)	673	474	483	493	507
Cape Verde	699	544	555	566	582
Cayman Islands	646	401	409	417	429
Central African Republic	332	224	229	233	240
Chad	741	655	668	681	700
Channel Islands	654	422	431	439	452
Chile	532	339	346	353	363

China (P.R. China & Hong Kong)	775	494	504	514	528
Colombia	309	231	235	240	247
Comoros	738	647	660	672	692
Congo, Democratic Republic of	16	43	44	45	46
Congo, Republic of	472	342	348	355	365
Cook Islands	519	326	333	339	349
Costa Rica	215	145	148	151	155
Côte d'Ivoire	530	436	444	453	466
Croatia	327	237	241	246	253
Cuba	755	598	610	622	640
Curaçao (Netherlands)	645	466	476	485	499
Cyprus	630	441	450	458	472
Czech Republic	794	501	511	521	536
Denmark	384	235	240	245	252
Djibouti	735	639	652	664	684
Dominica	702	551	562	573	590
Dominican Republic	566	460	469	478	492
Ecuador	586	404	412	420	432
Egypt	483	411	419	428	440
El Salvador	491	344	350	357	368
Equatorial Guinea	694	531	541	552	568
Eritrea	845	739	754	769	791
Estonia	1049	733	748	763	785
Eswatini	16	43	44	45	46
Ethiopia	16	44	44	45	47
Falkland Islands (U.K.)	645	399	407	415	426
Faroe Islands (Denmark)	631	362	369	376	387
Fiji	631	428	437	445	458
Finland	241	162	166	169	174
France	124	99	101	103	106
French Guiana	522	335	342	349	359
French Polynesia	661	443	452	460	474
Gabon	634	439	448	457	470
Gambia	736	643	656	668	688
Georgia	278	195	199	202	208
Germany	596	366	373	380	391
Ghana	509	360	367	374	385
Gibraltar (U.K.)	646	398	406	414	426
Greece	611	449	458	467	480
Greenland	633	367	374	381	392
Grenada	704	557	568	579	596
Guadeloupe (France)	666	454	463	472	486
Guam	663	447	456	465	478
Guatemala	564	402	410	418	430
Guinea	677	484	494	504	518
Guinea-Bissau	741	656	669	682	702
Guyana	723	607	619	632	650
Haiti	829	703	717	731	752
Honduras	654	473	482	492	506
Hong Kong (China)	576	396	404	412	424

Hungary	318	248	253	258	265
Iceland	16	43	44	45	46
India	878	673	686	700	720
Indonesia	677	637	650	663	682
Iran	570	470	480	489	503
Iraq	1159	934	953	971	999
Ireland	328	226	230	235	241
Isle of Man	391	303	309	315	324
Israel	391	303	309	315	324
Italy	359	252	257	262	269
Jamaica	672	543	553	564	581
Japan	456	381	389	396	408
Jordan	607	516	526	536	552
Kazakhstan	817	653	666	680	699
Kenya	478	317	323	330	339
Kiribati	721	602	614	626	645
Korea (North), Dem. People's Rep. of	622	407	415	423	435
Korea (South), Republic of	442	291	297	303	311
Kosovo	1005	832	849	866	891
Kuwait	578	407	415	423	435
Kyrgyzstan	218	156	159	162	167
Laos	549	366	373	380	391
Latvia	245	177	181	184	189
Lebanon	697	552	563	574	591
Lesotho	16	43	44	45	46
Liberia	574	407	415	423	436
Libya	632	538	549	559	575
Liechtenstein	135	97	99	101	104
Lithuania	302	215	219	224	230
Luxembourg	301	191	195	198	204
Macao (China)	370	239	244	248	256
Macedonia, North	921	691	705	718	739
Madagascar	538	377	385	393	404
Madeira (Portugal)	673	474	483	493	507
Malawi	16	43	44	45	46
Malaysia	551	470	480	489	503
Maldives	703	553	564	575	592
Mali	702	550	561	572	588
Malta	652	456	465	474	488
Marshall Islands	724	610	623	635	653
Martinique (France)	671	468	478	487	501
Mauritania	687	512	522	533	548
Mauritius	651	552	563	574	591
Mayotte (France)	700	545	556	567	583
Mexico	450	320	326	332	342
Micronesia	724	610	622	634	653
Moldova	503	436	445	454	467
Monaco	16	43	44	45	46
Mongolia	1272	1049	1070	1091	1122
Montenegro	830	544	554	565	582

Montserrat	699	542	553	564	580
Morocco	612	551	562	573	589
Mozambique	172	128	131	133	137
Myanmar	518	367	374	382	393
Namibia	195	134	136	139	143
Nauru	708	568	579	590	607
Nepal	16	43	44	45	46
Netherlands	280	221	226	230	237
Netherlands Antilles	677	485	495	505	519
New Caledonia (France)	652	417	426	434	447
New Zealand	235	160	163	166	171
Nicaragua	606	429	438	446	459
Niger	761	749	764	779	801
Nigeria	477	395	403	411	423
Niue	529	355	362	369	380
Northern Mariana Islands (U.S.)	678	486	496	505	520
Norway	55	61	62	64	65
Oman	494	381	389	396	408
Pakistan	594	453	463	472	485
Palau	694	530	541	552	567
Panama	551	361	368	375	386
Papua New Guinea	671	468	477	487	501
Paraguay	16	43	44	45	46
Peru	424	301	307	313	322
Philippines	543	489	499	508	523
Poland	765	568	579	591	608
Portugal	366	263	268	273	281
Puerto Rico (U.S.)	548	390	398	405	417
Qatar	424	276	281	287	295
Reunion (France)	658	430	439	447	460
Romania	455	332	339	345	355
Russian Federation	461	352	359	366	377
Rwanda	643	461	470	479	493
Saint Helena (U.K.)	488	310	316	322	331
Saint Kitts and Nevis	684	502	512	522	537
Saint Lucia	706	561	572	584	601
Saint Martin (France)	678	487	497	506	521
Saint Pierre and Miquelon (France)	658	432	441	450	463
Saint Vincent and Grenadines	691	521	531	542	557
Samoa	667	459	468	477	491
San Marino	16	43	44	45	46
Sao Tomé & Principe	694	530	541	551	567
Saudi Arabia	650	475	484	494	508
Senegal	674	568	579	590	607
Serbia	938	690	704	718	739
Seychelles	689	516	526	536	552
Sierra Leone	641	455	464	473	487
Singapore	366	249	254	259	266
Sint Martin (Netherlands)	671	469	478	488	502
Slovak Republic	285	201	206	210	216

Slovenia	536	329	335	342	352
Solomon Islands	732	631	643	656	675
Somalia	742	658	671	684	704
South Africa	1008	831	847	864	889
South Sudan	844	743	757	772	795
Spain	342	236	241	245	253
Sri Lanka	615	468	477	487	501
Sudan	530	352	359	366	377
Suriname	741	485	495	504	519
Sweden	60	64	65	67	69
Switzerland	39	55	56	58	59
Syrian Arab Republic	609	525	536	546	562
Taipei (Chinese)	482	365	372	379	390
Tajikistan	57	63	64	66	68
Tanzania	620	477	486	496	510
Thailand	428	390	397	405	417
Timor-Leste	732	630	643	655	674
Togo	527	341	348	355	365
Tonga	714	583	595	606	624
Trinidad and Tobago	561	424	433	441	454
Tunisia	470	404	412	420	432
Turkey	360	320	326	333	342
Turkmenistan	850	691	705	719	739
Turks and Caicos Islands (U.K.)	671	468	478	487	501
Tuvalu	693	528	539	549	565
Uganda	201	140	142	145	149
Ukraine	738	525	536	546	562
United Arab Emirates	522	353	360	367	378
United Kingdom	358	252	257	262	270
United States	418	285	290	296	305
Uruguay	237	158	161	164	169
Uzbekistan	610	506	516	526	542
Vanatu	634	371	378	385	397
Venezuela	534	345	352	358	369
Vietnam	385	356	363	370	381
Virgin Islands (U.S.)	560	375	382	390	401
West Bank and Gaza	730	625	638	650	669
Yemen	724	636	649	662	681
Zambia	129	99	101	103	106
Zanzibar (Tanzania)	739	648	661	674	694
Zimbabwe	1302	883	900	918	944
EU 28	399	266	271	277	285

Source: emission factors based on the IFI Dataset of Default Grid Factors v.2.0 from July 2019, created by the IFI Technical Working Group on GHG Accounting. The methodological approach can be found on the UNFCCC's website: https://unfccc.int/sites/default/files/resource/IFITWG_Methodological_approach_to_common_dataset.pdf

Table A1.4 Build Margins for Electricity and Heat Generation Factors by Unit[11]

Unit type	Fuel	Generation Efficiency	Emissions Factor t CO_2e/TJ	oxidised combustion	Emissions Factor t CO_2e /GWh
Electricity Production					
Combined Cycle Gas Turbine (CCGT)	natural gas	0.57	56.2	0.995	353
	light fuel oil	0.55	74.3	0.990	481
Open Cycle Gas Turbine (GT)	natural gas	0.35	56.2	0.995	575
	light fuel oil	0.35	74.3	0.990	757
Steam Turbine Combustion	natural gas	0.44	56.2	0.995	457
	light fuel oil	0.44	74.3	0.990	602
	heavy fuel oil	0.44	77.6	0.990	629
Diesel Engine Combustion	natural gas	0.44	56.2	0.995	457
	light fuel oil	0.44	74.3	0.990	602
	heavy fuel oil	0.44	77.6	0.990	629
Super Critical Pulverised Coal	coal	0.44	98.7	0.980	791
	lignite	0.42	101.4	0.980	851
Hydro, Geothermal, Wind, Solar	renewable	0	0.0	0	0
Nuclear	uranium	0	0.0	0	0
Heat Production					
Industrial Steam Boiler	natural gas	0.93	56.2	0.995	216
	light fuel oil	0.90	74.3	0.990	294
	heavy fuel oil	0.90	77.6	0.990	308
Residential Heat Boiler	natural gas	0.90	56.2	0.995	223
	light fuel oil	0.85	74.3	0.990	312

Table A1.5 Integrated Iron and Steel Emissions Factors by Unit

Unit type	Emissions Factor	Units
Coke Oven - standard	0.15	t CO_2 / t coke
Coke Oven with heat recovery and power generation	1.08	t CO_2 / t coke
Sinter Strand	0.24	t CO_2 / t sinter
Blast Furnace	0.31	t CO_2 / t iron
BOS Furnace	0.06	t CO_2 / t liquid steel
Continuous Casting Plant	0.00	t CO_2 / t steel
Hot Wide Strip Mills	0.10	t CO_2 / t steel
Annealing Line	0.06	t CO_2 / t steel
Billet Mills	0.26	t CO_2 / t steel
Reversing Mills	0.25	t CO_2 / t steel
Medium Section Mills	0.25	t CO_2 / t steel
Heavy Section Mills	0.29	t CO_2 / t steel
Bar Mills	0.16	t CO_2 / t steel
Section Mill	0.09	t CO_2 / t steel
Secondary steelmaking	0.01	t CO_2 / t liquid steel

Source: Refer to EU ETS Phase II New Entrants' Benchmark Review: Integrated Iron and Steel Benchmark Review Report http://www.decc.gov.uk/media/viewfile.ashx?filepath=what we do/global climate change and energy/tackling climate change/emissions trading/eu_ets/euets_phase_2/newenrants/benchmark_revi/file33265.pdf&filetype=4&minwidth=true

[11] Assumptions for Build Margin technologies can be found in Annex 2.

Table A1.6 Glass Production Carbonate Emissions Factors

Carbonate	Emissions Factor [t CO_2/t carbonate]
CaCO3	0.44
MgCO3	0.52
NA1CO3	0.42
BaCO3	0.22
Li2CO3	0.60
K2CO3	0.32
SrC03	0.30
NaHCO3	0.52

Source: EU ETS Monitoring and Reporting Guidelines 2007 Establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council Annex IX Table 1 (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF)

Tables A1.7 Transport Emissions Factors

Road transport						
		EC (MJ/vkm)	TTW g CO_2e/ vkm	Avarage Occupation / load	EC (MJ/pkm)	TTW CO_2e/ pkm or tkm
Cars						
Car average	Average	2.51	180	1.4	1.79	128
	Urban	3.36	240	1.4	2.40	172
Car diesel	Average	2.38	169	1.4	1.70	121
	Urban	3.11	220	1.4	2.22	157
Car gasoline	Average	2.68	195	1.4	1.91	139
	Urban	3.67	268	1.4	2.62	191
Car LPG	Average	2.68	180	1.4	1.91	129
	Urban	3.39	228	1.4	2.42	163
Car CNG	Average	2.86	170	1.4	2.04	121
	Urban	3.86	229	1.4	2.76	164
Hybrid petrol	Average	1.81	128	1.4	1.30	92
	Urban	2.37	168	1.4	1.69	120
Car electric average size)	Average	0.84	0	1.4	0.60	-
	Urban	0.73	0	1.4	0.52	-
Buses						
Average urban bus	Average	12.18	862	8.9	1.38	97
Urban Buses Midi <=15 t	Average	9.96	705	6.7	1.50	106
Urban Buses Standard 15 - 18 t	Average	13.45	952	9.5	1.42	100
Urban Buses Articulated >18 t	Average	16.89	1196	19.0	0.89	63
Urban CNG buses (standard)	Average	21.60	1284	9.5	2.27	135
Urb. buses diesel hyb. (standard)	Average	11.42	809	9.5	1.20	85
Urb. buses electric (standard)	Average	7.83	0	9.5	0.82	-
Coaches						
Coaches average	Average	11.06	783	34.4	0.32	23

Coaches Standard <=18 t	Average	10.55	746	25.0	0.42	30
Coaches Articulated >18 t	Average	11.92	844	50.0	0.24	17
Two-wheelers						
E-Bike	Electric	0.05	0	1.0	0.05	-
Mopeds	Av. petrol	0.93	74	1.1	0.84	67
	Av. elect.	0.15	0	1.1	0.14	-
Motorcycle	Average	1.39	102	1.2	1.21	88
LCVs						
LCV -average	Average	3.41	241			
HGVs						
HGV average	Average	8.53	604	7.8	1.09	77
HGV Rigid <=7,5 t	Average	4.44	315	0.9	5.14	364
HGV Rigid 7,5 - 16 t	Average	6.57	465	2.6	2.52	178
HGV Rigid 16-32 t	Average	8.90	630	6.0	1.50	106
HGV Rigid >32 t	Average	11.14	789	15.1	0.74	52

Source: COPERT (Emissions calculation tool produced by EEA) completed with STREAM (CE DELFT)

Rail passenger						
		EC (MJ/seatm)	TTW g CO_2e/ seat-km	Average occ . Rate (%)	EC (MJ/tkm)	TTW CO_2e/ pkm
Electric	Average	0.11	-	35%	0.31	0.0
	Regional/ Suburban	0.09	-	25%	0.35	0.0
	Intercity	0.12	-	36%	0.34	0.0
	Highspeed	0.11	-	48%	0.22	0.0
Diesel	Average	0.26	18.5	24%	1.09	76.9
	Regional/ Suburban	0.22	15.4	20%	1.10	76.9
	Intercity	0.31	21.7	28%	1.09	76.9
Average	Average	0.00	0.0			6.4

Source: UIC

Rail freight						
		EC (MJ/vkm)	TTW g CO_2e/ vkm	Load (tonne)	EC (MJ/tkm)	TTW CO_2e/ ton-km
El. average	Av. train (1000t - 21W)	59.8	-	516	0.116	0.0
El. bulk	Av. train (1000t - 18W)	59.8	-	597	0.100	0.0
El. volume	Av. train (1000t - 26W)	59.8	-	400	0.150	0.0
El. container	Av. train (1000t - 21W)	59.8	-	563	0.106	0.0
Diesel average	Av. train (1000t - 21W)	161.5	11,434	516	0.313	22.2
Diesel bulk	Av. train (1000t - 18W)	161.5	11,434	597	0.271	19.2
Diesel volume	Av. train (1000t - 26W)	161.5	11,434	400	0.404	28.6
Diesel container	Av. train (1000t - 21W)	161.5	11,434	563	0.287	20.3

Source: Ecotransit 2018

Inland waterways transport						
	Vessel type	EC (MJ/vkm)	TTW g CO_2e/ vkm	Load (tonne)	EC (MJ/tkm)	TTW CO_2e/ tkm
Inland Ships bulk	Rhine-Herne canal vessel (1,537t)	323	22,865	807	0.40	28.3
	Large Rhine vessel (3,013t)	347	24,564	1,665	0.21	14.8
	4-barge push convoy (11,181t)	1203	85,161	6,178	0.19	13.8
Container	Europe IIa push convoy (160 TEU)	411	29,095	912	0.45	31.9
	Large Rhine vessel (208 TEU)	307	21,733	1,186	0.26	18.3

Source: STREAM Freight 2016 (CE DELFT)

Shipping						
Type	size	EC (MJ/vkm)	TTW kg CO_2e/ vkm	Load (tonne)	EC (MJ/tkm)	TTW g CO_2e/ tkm
Bulk carrier	0-9999	730	56.74	2,335	0.313	24.3
Bulk carrier	10000-34999	1,615	125.63	14,935	0.108	8.4
Bulk carrier	35000-59999	2,144	166.72	26,089	0.082	6.4
Bulk carrier	60000-99999	2,633	204.76	35,036	0.075	5.8
Bulk carrier	100000-199999	3,677	285.99	89,812	0.041	3.2
Bulk carrier	200000-+	5,435	422.75	150,873	0.036	2.8
Chemical tanker	0-4999	680	52.91	1,899	0.358	27.9
Chemical tanker	5000-9999	1,270	98.79	5,367	0.237	18.4
Chemical tanker	10000-19999	1,615	125.63	9,705	0.166	12.9
Chemical tanker	20000-+	2,448	190.40	22,346	0.110	8.5
Container	0-999	1,299	101.00	5,344	0.243	18.9
Container	1000-1999	2,694	209.52	12,139	0.222	17.3
Container	2000-2999	3,262	253.75	18,808	0.173	13.5
Container	3000-4999	4,002	311.27	26,755	0.150	11.6
Container	5000-7999	5,239	407.49	36,392	0.144	11.2
Container	8000-11999	6,460	502.45	51,391	0.126	9.8
Container	12000-14500	7,292	567.19	78,668	0.093	7.2
General cargo	0-4999	414	32.23	1,545	0.268	20.9
General cargo	5000-9999	1,090	84.76	4,498	0.242	18.8
General cargo	10000-+	2,627	204.33	12,186	0.216	16.8
Liquefied gas tanker	0-49999	735	57.19	3,444	0.213	16.6
Liquefied gas tanker	50000-199999	4,864	378.28	42,489	0.114	8.9
Liquefied gas tanker	200000-+	7,004	544.73	53,619	0.131	10.2
Oil tanker	0-4999	814	63.29	1,655	0.492	38.2
Oil tanker	5000-9999	1,659	129.06	4,902	0.338	26.3
Oil tanker	10000-19999	2,429	188.90	9,501	0.256	19.9
Oil tanker	20000-59999	2,523	196.21	14,968	0.169	13.1
Oil tanker	60000-79999	2,962	230.39	25,564	0.116	9.0
Oil tanker	80000-119999	3,476	270.36	37,499	0.093	7.2
Oil tanker	120000-199999	4,406	342.68	58,092	0.076	5.9
Oil tanker	200000-+	6,202	482.36	134,417	0.046	3.6

Refrigerated bulk	0-1999	2,467	191.87	3,810	0.647	50.4

Source: IMO-UCL Study 2015

Passenger aviation							
	Type	EC (MJ/seatkm)	TTW g CO_2e/ seat-km	Average occ. Rate (%)	EC (MJ/pkm)	Without RF TTW g CO_2e/ pkm	With RF TTW g CO_2e/ pkm
Domestic	Average passenger	1.61	116	74%	2.2	158	298
Short-haul	Average passenger	0.95	69	80%	1.2	86	162
Long-haul	Average passenger	1.15	83	74%	1.6	112	212
International	Average passenger	1.07	77	80%	1.3	97	183
	Economy class	0.82	59	80%	1.0	74	140
	Premium economy class	1.31	94	80%	1.6	118	224
	Business class	2.37	171	80%	3.0	215	406
	First class	3.27	236	80%	4.1	296	560

Source: DEFRA

Aviation freight				
	Type	EC (MJ/tkm)	Without RF TTW g CO_2e/ tkm	With RF TTW g CO_2e/ tkm
Freight	Domestic, to/from UK	42.8	3,084	5,833
	Short-haul, to/from UK	14.3	1,029	1,946
	Long-haul, to/from UK	9.0	651	1,232
	International, to/from non-UK	9.0	651	1,232

Source: DEFRA

Table A1.8 Reservoir GHG Emissions Factors

Source: IPCC Good Practice Guidance for LULUCF, 2003 Table 3A.3.5

GUIDANCE: *The key default values needed to implement the EIB methodologies are emission factors for CO_2, CH_4 and N_2O via the diffusion pathways, and an emission factor for CH4 via the bubbles pathways. The table below provides default emission factors for various climate zones that can be used. These default emission factors integrate some spatial and temporal variations in the emissions from reservoirs, as well as fluxes at the water-air interface of reservoirs. All default data have been obtained from measurements in hydroelectric or flood control reservoirs. The emissions factors for the ice-free period should be used for the entire year*

	Diffusive emissions (ice-free period) Ef (GHG)diff (kg ha-1 d-1)		
Climate	**CH_4**	**CO_2**	**N_2O**
Boreal, wet	0.11 ± 88%	15.5 ±56%	0.008 ±300%
Cold temperate, wet	0.2 ±55%	9.3 ±55%	nm
Warm temperate, dry	0.063 ± 0.032	-3.1 ±3.6	nm
Warm Temperate, wet	0.096 ± 0.074	13.2 ±6.9	nm
Tropical, wet	0.64 ±330%	60.4 ±145%	0.05 ±100%
Tropical, moist-long dry season	0.31 ±190%	11.65 ±260%	nm
Tropical, moist-short dry season	0.44 ±465%	35.1 ±290%	nm
Tropical, dry	0.3 ±115%	58.7 ±270%	nm
	Bubbles emissions (ice-free period) Ef (GHG) bubble (kg ha-1 d-1)		
Boreal, wet	0.29 ±160%	ns	ns
Cold temperate, wet	0.14 ± 70%	ns	ns
Tropical, wet	2.83 ±45%	ns	ns
Tropical, moist-long dry season	1.9 ±155%	ns	ns
Tropical, moist-short dry season	0.13 ±135%	ns	ns
Tropical, dry	0.3 ±324%	ns	ns
	Emissions associated with the ice cover period Ei (GHG)diff + Ei (GHG) bubble (kg ha-1 d-1)		
Boreal, wet	0.05 ±60%	0.45 ±55%	nm

nm = not measured, ns = not significant

Table A1.9 IPCC Global Warming Potential (GWP) Factors

Source: IPCC Fifth Assessment Report, 2014 (AR5) from the GHG Protocol, 2018

Gas	Chemical formula	Global warming potential (100-year time horizon)
Carbon dioxide	CO_2	1
Methane	CH_4	28
Nitrous oxide	N_20	265
Hydrofluorocarbons (HFCs)		
HFC-23	CHF_3	12,400
HFC-32	CH_2F_3	677
HFC-41	CH_3F	116
HFC-43-10mee	$C_5H_2F_{10}$	1,650
HFC-125	C_2HF_5	3,170
HFC-134	$C_2H_2F_4$ (CHF_2CHF_2)	1,120
HFC-134a	$C_2H_2F_4$ (CH_2FCF_3)	1,300
HFC-143	$C_2H_3F_3$ (CHF_2CH_2F)	328
HFC-143a	$C_2H_3F_3$ (CF_3CH_3)	4,800
HFC-152a	$C_2H_4F_2$ (CH_3CHF_2)	138
HFC-227ea	C_3HF_7	3,350
HFC-236fa	$C_3H_2F_6$	8,060
HFC-245ca	$C_3H_3F_5$	716
Hydrofluoroethers (HFEs)		
HFE-449sl (HFE-7100)	$C_4F_9OCH_3$	421
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	57
Perfluorocarbons (PFCs)		
Perfluoromethane (tetrafluoromethane) PFC-14	CF_4	6,630
Perfluoroethane (hexafluoroethane) PFC-116	C_2F_6	11,100
Perfluoropropane PFC-218	C_3F_8	8,900
Perfluorobutane PFC-3-1-10	C_4F_{10}	9,200
Perfluorocyclobutane PFC-318	$c\text{-}C_4F_8$	9,540
Perfluoropentane PFC-4-1-12	C_5F_{12}	8,550
Perfluorohexane PFC-5-1-14	C_6F_{14}	7,910
Sulfur hexafluoride	SF_6	23,500

ANNEX 2: APPLICATION OF ELECTICITY GRID EMISSION FACTORS FOR PROJECT BASELINES

1. ELECTRICITY GENERATION PROJECTS

With respect to energy generation projects, it is recommended that for grid-connected electricity generating projects a combined margin, which is a weighted average of operating margin and build margin should be used to define the baseline emissions of the project. For this purpose, the EIB will use the figures from the IFI Dataset of Default Grid Factors v.2.0 from July 2019, which was created by the IFI Technical Working Group on GHG Accounting.

1.1 Operating Margin

The operating margin (OM) is the emissions factor associated with the power plants whose current electricity generation would be affected by the proposed project activity. In principle, it would comprise the power plants operating on the margin of the generation dispatch merit order and could include any type of generation. For special cases (peak power, pumped storage or direct replacement) specific marginal plants can be assumed for the OM. However, as a reference for most projects, it is assumed that the OM consists of generation from the power plants with the highest variable operating costs in the electricity system, mainly natural gas and oil, and coal and lignite generation if solid fossil fuels make up a large proportion of the generation mix. Renewable, nuclear and “must run” fossil fuel-fired generation such as combined heat and power plants for district heating, which would not be affected by the project, are generally excluded from the OM.

1.2 Build Margin

The build margin (BM) is the emission factor that refers to power plants whose construction and future operation would be affected by the proposed project activity. EIB takes a five-year forward looking perspective when determining the build margin technologies.

In principle, gas, fuel oil, coal, lignite, renewable energy (mainly intermittent) and nuclear plants may be built and could be part of the build margin. However, for simplicity and taking a conservative position on CO_2 emissions savings made by renewable energy, on mainland Europe where natural gas is available, the build margin for base load power plants connected to the grid will be assumed to be 100% based on the emissions from combined cycle gas turbine (CCGT) technology. On isolated island grids where gas is not available or where large scale power plants are not feasible, the BM will be based on the most appropriate fuel oil alternative (CCGT or diesel engine). For peak load generation, the most appropriate alternative may include a combination of base load and peak load power plants (open cycle gas turbines or diesel engines). The BM for heat boilers will be based on natural gas where gas distribution networks are available, or otherwise on fuel oil.

The same principles apply for the baseline in countries outside Europe, except for countries where large-scale power plants are required and gas is not available. In these countries, the only viable thermal alternative will include coal. In addition, where significant sources of hydro and geothermal power are available (firm as opposed to intermittent), renewable energy may also make a significant contribution to the baseline.

A harmonised approach to calculating the BM has been agreed with IFIs[12], and a harmonised dataset has been produced. It can be found in table A1.3.

2. PURCHASED ELECTRICITY

Projects that purchase electricity from the grid must take into account the losses from the transmission and distribution (T&D) of the electricity. The size of the losses will depend on the project’s capacity, i.e. whether it is connected to the high, medium or low voltage grid. The grid emission factors, including T&D losses, are located in table A1.3 in the methodologies. For simplicity T&D losses are assumed to be as follows:

[12] IFI Approach to GHG Accounting for Renewable Energy Projects, November 2015 (www-wds.worldbank.org)

- High voltage grid: 2% T&D losses. Projects with >10MW consumption generally will be connected to the high voltage grid, e.g. high-speed rail, large heavy industry projects
- Medium voltage grid: 4% T&D losses. This includes most industry projects
- Low voltage grid: 7% T&D losses. This includes all residential and commercial projects.

3. NETWORK INVESTMENTS – GAS AND ELECTRICITY

Networks are transporters of energy and are usually mandated to meet supply requirements/demand growth. The baseline will usually supply the same amount of energy as the project, either less efficiently (without the project) or using similar new infrastructure (no economic alternative). For the purposes of EIB carbon footprint methodology, the investments in gas and electricity transmission and distribution networks are divided into 3 categories. Each category is characterised by its objectives and its contribution to GHG emissions:

i) Some investments are primarily intended to improve commercial operations, service quality and/or security of supply. These investments may facilitate customer billing or reduce O&M costs, or they may be required by the regulator or mandated to meet new environmental/safety standards. The investments are characterised as having little or no impact on GHG emissions and their effects are excluded from the carbon footprint calculation.

ii) Other investments are required to maintain the condition of the existing network. These investments are characterised by the **rehabilitation/replacement** of existing assets and are intended to ensure the long term supply of electricity or gas. Energy losses (for electricity transmission and distribution networks), energy consumption (for gas transmission and distribution networks) and fugitive emissions (for gas distribution networks) are the main sources of GHG emissions. The carbon footprint for these investments is based on a percentage share of the total emissions for the network that is in proportion with the percentage share of the network assets replaced or rehabilitated.

    Calculation: CO_2 emissions are estimated for the entire network and an emissions factor per unit of supply is calculated. The volume of supply used is that of the last year of operation, prior to start of project construction. Assumptions are made about the emissions factor with and without the project. In most cases, emissions for the current level of supply would go up without the investment. The percentage share of the network assets replaced/rehabilitated is estimated. Carbon footprints (absolute and baseline) are calculated using this percentage share of the total emissions of the network (with and without the project) for the pre-project levels of demand.

iii) Still other investments are required to meet growing demand. These investments are characterised by **network extensions**, upgrades of capacity and new connections. In reality, these investments are difficult to separate physically from the rehabilitation and replacement of assets or even from those required for commercial or regulatory reasons, but their GHG emissions impact is related to increasing the supply of electricity or gas through the entire network.

    Calculation: CO_2 emissions factors (with and without the project) per unit of supply are estimated as above. These factors are applied to the incremental demand that is accommodated as a result of the project (typically 3-4 years of demand growth). All emissions associated with the incremental demand are attributed to the project.

ANNEX 3: FORESTRY CARBON FOOTPRINT CALCULATION METHODOLOGY

The operational boundary of forestry projects, which defines the emission sources to be included for forestry projects, includes:

- **Scope 1 emissions**
  - Fuel consumption associated with site preparation, management, etc.
  - Emissions from fertilizer use
- **Scope 2 emissions**
  - Electricity consumption
- **Scope 3 emissions**
  - Not included
- **Carbon sequestration**
  - Carbon sequestration due to biomass growth
  - Loss of carbon sequestration due to biomass removals (e.g. thinning and harvesting)

The absolute emissions are measured as the average annual emissions over the project lifetime:

$$\begin{aligned}
&Absolute\ emissions\ \left(\frac{t\ CO_2e}{year}\right) \\
&\quad = average\ annual\ fuel\ consumption\ emissions\ \left(\frac{t\ CO_2e}{year}\right) \\
&\quad + average\ annual\ fertilizer\ consumption\ emissions\ \left(\frac{t\ CO_2e}{year}\right) \\
&\quad + average\ annual\ scope\ 2\ emissions\ \left(\frac{t\ CO_2e}{year}\right) \\
&\quad - average\ annual\ carbon\ sequestration\ \left(\frac{t\ CO_2e}{year}\right)
\end{aligned}$$

Emissions and carbon sequestration levels are calculated on an average annual basis over the full rotation cycle (economic lifetime) of the forest and not only the project lifetime. Taking an average over this time-period is important as biomass growth and carbon sequestration is not linear for forest growth due to changing growth rates depending on the forest management regime applied, impact of thinning and harvesting, other management interventions, and natural conditions. GHG emissions and removals related to the management of forest resources are accounted as per the LULUCF Regulation EU 2018/841 EU. Wood removals as part of sustainable forest management practices (such as tending, thinning, and final cuts followed by forest regeneration) increase carbon sequestration at a general forest inventory level in comparison to unmanaged or poorly managed forests.

Unmanaged or poorly managed forests have much lower growth rates as compared to sustainably managed forests. In addition, sustainable forest management activities also apply the concept of preserving high biodiversity and high carbon stock areas such as peatlands. The economic lifetime is generally aligned with the time of harvesting, meaning that GHG removals from harvesting is accounted for when calculating the average annual carbon sequestration.

The *average annual fuel consumption emissions* related to forest management are calculated by multiplying the fuel average annual fuel consumption over the forest's economic lifetime (e.g. diesel, gasoline, etc.) with the standard fuel-specific emission factor (e.g. kg CO_2e/litre).

The *average annual fertilizer consumption emissions* (on the field) are calculated by multiplying the input consumption (e.g. tons of fertilizer) with an input-specific emission factor (t CO_2e/t of input) from acknowledged databases such as Ecoinvent or emission factor information from the input producer.

When calculating the *average annual carbon sequestration* in forest biomass, EIB accounts for annual forest biomass growth (annual increment), as well as for forest biomass reductions due to forest tending, thinning and harvesting activities within the full economic lifetime (rotation cycle) of the forest (i.e. which is typically longer than then the project lifetime). Such biomass reductions are directly subtracted from the carbon sequestered.

Carbon sequestration is accounted for both belowground and aboveground biomass. Based on IPCC Guidelines[13], the following formula is used to calculate the average annual carbon sequestration of EIB's forestry projects measured in t CO_2e/year:

$$Average\ annual\ carbon\ sequestration\ \left(\frac{t\,CO_2e}{year}\right) = \left[MAI\left(\frac{\frac{m^3}{ha}}{year}\right)\right] x\ [BCEF]\ x\ [1 + R]\ x\ \left[CF\ \left(\frac{t\,C}{t\ dry\ matter}\right)\right] x\ \left[CCF\ \left(\frac{t\,CO_2e}{t\,C}\right)\right] x\ [Forest\ area\ (ha)]$$

Where:

- *MAI - Mean annual increment* (or mean annual growth) refers to the average growth per year of a forest stand, which is a variable depending on the specific local site and climate conditions, tree species, rotation period, forest management practices applied (e.g. intensity of tending/thinning operations), etc. The MAI used by EIB is calculated for the local specific conditions and forest management practices applied in each project. The information on MAI is provided by project promotors at project appraisal and then scrutinized against EIB's own expert knowledge and default MAI values from sources such as FAO's data on forests growth[14] or IPCC Guidelines.
- *BCEF (biomass conversion and expansion factor)* refers to the expansion factor of merchantable growing stock volume to above-ground biomass. BCEF transforms merchantable volume of growing stock directly into its aboveground biomass. BCEF values are more convenient because they can be applied directly to volume based forest inventory data and operational records, without the need of having to resort to basic wood densities (D). They provide best results, when they have been derived locally and based directly on merchantable volume. However, if BCEF values are not available and if the biomass expansion factor (BEF) for wood removals, which is dimensionless, and wood density (D) values are separately estimated, the following conversion can be used:

  $$BCEF = BEF\ x\ D\ (\frac{t}{m^3})$$

  If country-specific data on roundwood removals are not available, expert knowledge or FAO statistics on wood harvests will be used. Given that FAO statistical data on wood harvests exclude bark, the FAO statistical wood harvest data without bark will be multiplied by a default expansion factor of 1.15 to convert it into merchantable wood removals including bark.
- *D (wood density)* – the basic wood density (expressed in tons/m^3) varies by species and climate conditions (0.2 to 0.9 in tropical forests and 03 to 0.6 in temperate forests). Wood density is conservatively estimated based on expert knowledge and available reference documents[15], and the default used value is 0.5 tons/m^3.
- *R* refers to *ratio of belowground biomass to aboveground biomass* or root to shoot ratio for a specific vegetation type, in tonne dry matter belowground biomass (tonne dry matter aboveground biomass)$^{-1}$. R is conservatively estimated based on expert knowledge and available reference documents and must be set to zero when assuming no changes of belowground biomass allocation patterns.

[13] 2006 IPCC Guidelines for National Greenhouse Gas Inventories – Volume 4: Agriculture, Forestry and Other Land Use
[14] FAO's Global Planted Forests Assessment: Global planted forests thematic study (2006)
[15] Overview of wood densities for several different tree species: from Estimating Biomass and Biomass Change of Tropical Forests: a Primer. (FAO Forestry Paper - 134); 2006 IPCC Guidelines for National Greenhouse Gas Inventories – Volume 4: Agriculture, Forestry and Other Land Use

- *CF* is a conversion factor that refers to *carbon fraction of dry matter*, expressed in tons of C per ton of dry matter. Using a conservative approach of default values for wood carbon content[16], the default CF *value* assumed in calculations is 0.5 (t C/t dry matter).
- *CCF* – is *carbon conversion factor from C to CO_2e* calculated as follows:

$$conversion\ factor\ from\ C\ to\ t\ CO_2e = \frac{12 + (16\ x\ 2)}{12} = 3.67$$

- *Forest area (ha)* is the project's forest area provided by the Promotor and verified by the EIB.

After having calculated the absolute emissions from the project and the absolute emissions of the baseline (calculated based on the same methodology as *with project* scenario), the relative emissions can be estimated. The relative emissions are calculated by subtracting the baseline absolute emissions from the project absolute emissions:

$$Relative\ emissions\ \left(\frac{t\ CO_2e}{year}\right) = Project\ absolute\ emissions\ \left(\frac{t\ CO_2e}{year}\right) - Baseline\ absolute\ emissions\ \left(\frac{t\ CO_2e}{year}\right)$$

For the baseline definition, EIB assumes zero baseline absolute emissions/sequestration for afforestation projects, while it does not assume a zero baseline for forest rehabilitation where, for example, the MAI is improved through forestry management practices in comparison to the baseline. The reason is that in case of forest rehabilitation, a forest is generally already existing, but either unmanaged or poorly managed, meaning that carbon is also sequestered in the baseline scenario, however at a lower level compared to sustainably managed forests.

Alternatively, in the absence of reliable data for calculating the GHG emissions based on the methodology described above, the Bank may use the default emissions/sequestration values from IPCC Guidelines[17] or the Ex-Ante Carbon-balance Tool (EX-ACT)[18], which is an appraisal system developed by the Food and Agriculture Organization of the United Nations (FAO) providing estimates of the impact of agriculture and forestry development projects, programmes and policies on the carbon-balance.

[16] At present, 50% carbon content (w/w or "weight by weight", the proportion of carbon compared to wood mass, as measured by weight) is widely promulgated as a generic value for wood. Carbon in kiln-dried hardwood species, for example, ranged from 46.27% to 49.97% (w/w), in conifers from 47.21% to 55.2% (see Lamlom & Savidge (2003): A reassessment of carbon content in wood: variation within and between 41 North American species).
[17] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry and Other Land Use, Chapter 4 – Forest Land, Section 4.5
[18] FAO Ex-Ante Carbon-balance Tool (EX-ACT): http://www.fao.org/tc/exact/ex-act-home/en/

ANNEX 4: LAND USE CHANGE CARBON-BALANCE CALCULATION (EX-ACT)

Agriculture and forestry sectors are of key concern in meeting climate change challenges, both as these sectors are responsible for a significant share of greenhouse gas (GHG) emissions and, at the same time, they could potentially play an important role in climate change mitigation. For instance, well designed forestry and agriculture projects can play an important role in climate change mitigation, either by reducing emissions or by sequestering carbon in soil and biomass.

However, one of the main barriers to implement the potential of agricultural mitigation is the lack of methodologies or approaches that would help project designers to integrate significant mitigation effects in agriculture and forestry development projects.

The IPCC has published guidelines and good practices for GHG accounting (IPCC 2006) and various tools have been developed to help those performing GHG assessment within these guidelines. These tools provide a framework for the assessments and a database of emission factors and can be classified as; calculators, protocols, guidelines and models.

An Ex-ante Appraisal Carbon Balance Tool (EX-ACT), was developed by the Food and Agriculture Organization of the United Nations (FAO) to provide ex-ante measurements of the impact of agriculture and forestry development projects on GHG emissions and Carbon (C) sequestration, indicating their effects on the carbon balance. The EIB can use EX-ACT for projects in the Agriculture, Forestry and Other Land Use (AFOLU) sub-sectors, including - besides others - cropland agriculture, forestry, livestock and fisheries.

EX-ACT version 8 has been developed using primarily the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2006) and IPCC 2013, 2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands (IPCC 2013). It was complemented by other existing methodologies and reviews of default coefficients where available. Embodied GHG emissions for farm operations, inputs, transportation and irrigation systems implementation are from Lal (2004). Emissions factors for the fishery sector are scientific literature-based, from Parker & Tyedmers (2014), Sciortino (2010), Winther *et al.* (2009) and Irribaren *et al.* (2010 & 2011). EX-ACT (version 9) is currently being upgraded according to the IPCC 2019, Refinement to the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC 2019).

Structure of EX-ACT[19]. EX-ACT consists of a set of 18 linked Microsoft Excel sheets into which project sector experts insert information on dominant soil types and climatic conditions of the project area together with basic data on land use, land use change and land management practices foreseen under projects activities as compared to a “business as usual” scenario. EX-ACT adopts a modular approach – each “Module” describing a specific land use – and following a three-step logical framework:

(i) General description of the project (geographic area, climate and soil characteristics, duration of the project);
(ii) Identification of changes in land use and technologies foreseen by project components (deforestation, afforestation/reforestation, annual/perennial crops, rice cultivation, grasslands, livestock, inputs, energy); and
(iii) Computation of the carbon-balance with and without the project using IPCC default values and when available – ad-hoc coefficients.

Methodologies behind EX-ACT[20]. EX-ACT is based on the six broad categories (and sub-categories) proposed for reporting GHG inventories, but is focused mostly on three categories: Forestland, Cropland, and Grassland. Three approaches may be used to represent areas under a specific land use depending on the level of detail of the available information. The tool considers information on conversions between categories, but without full spatially explicit location data. The result of this approach can be represented as a land-use change matrix between categories.

When performing an ex-ante analysis the user should have an idea on:

(i) What would happen without the project (i.e. the Business As Usual – BAU – Scenario or as referred to in this document as “Baseline” linking to the overall EIB GHG footprint

[19] http://www.fao.org/tc/exact/ex-act-home/en/

[20] Bernoux et al. Ex-ante greenhouse gas balance of agriculture and forestry development programs. 2010. Sci. Agric. (Piracicaba, Braz.), v.67, n.1,p.31-40.

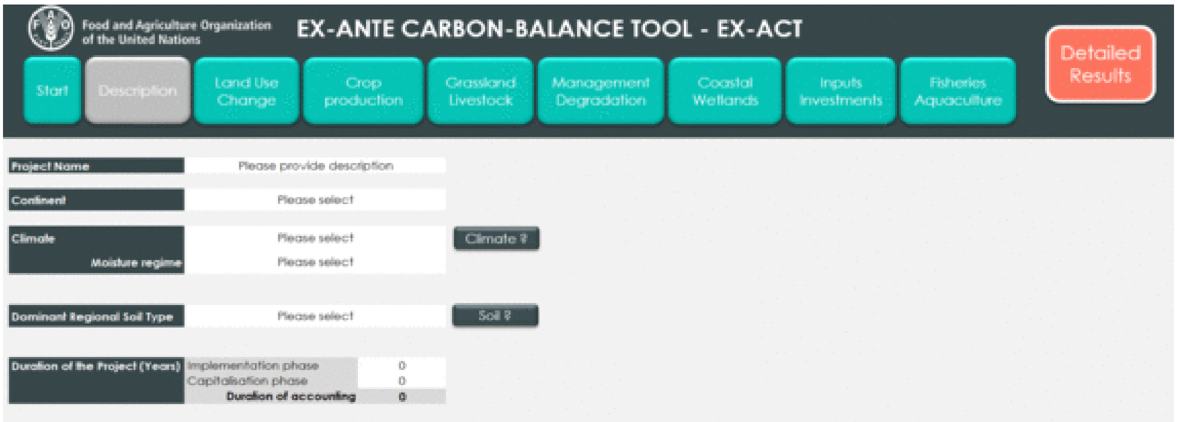
methodology), thus the final balance is the comparison between the GHG emissions associated with the project compared with the baseline scenario.

(ii) Definition of the two time periods; one for the implementation phase, i.e. the active phase of the project commonly corresponding to the funding and investment phase, and another for the capitalization phase, i.e. a period where the benefits of the investment are still occurring and may be attributed to the changes induced by the adoption of the project.

Generic methodologies for estimating carbon pools changes (CO_2 balance) - Calculation of changes in carbon pools is made using methods that can be applied in a very similar way for the type of land use change (i.e. generic methods). Generic methodologies are used mainly to account for changes between two categories during conversion, and concerns the five pools defined by IPCC guidelines and UNFCCC: above-ground biomass, below-ground biomass, soil, deadwood and litter.
Most calculations, except where specified, use a default value with a stock-difference method for emission of CO_2, calculated as the change of carbon stocks for the different pools, default values are proposed for each pool of each category (or subcategory or even main vegetation type).

Generic methodologies for non-CO_2 GHG - For N_2O and CH_4 emissions, the generic approach consists of multiplying an emission factor for a specific gas or source category with activity data related to the emission source (e.g. area, animal numbers or mass unit). Emissions of N_2O and CH_4 are either associated with a specific land use category or subcategory (e.g. CH_4 emissions from rice), or are estimated at project aggregated data (e.g. emissions from livestock and N_2O emission from fertilizers). CH_4 and N_2O emissions are converted into CO_2e emissions based on the global warming potential of each gas. The user has the ability to use either the official values under the Kyoto Protocol of the UNFCCC, or the last update provided by the IPCC (2007).

The tool can be downloaded from the http://www.fao.org/tc/exact/ex-act-home/en/ web site, where the user manual is available in various languages.



ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY

Airports

Absolute GHG emissions

To calculate the absolute airport GHG emissions, the following formula is used:

$$Absolute\ GHG\ emissions =$$
$$= Scope\ 1\ \&\ 2\ GHG\ emissions + Scope\ 3\ GHG\ emissions\ from\ Landing\ and\ Takeoff\ (LTO)\ \text{cycle (incl. engine run} - \text{up \& testing, APUs etc.)}$$

The ***scope 1 & 2 GHG emissions*** are calculated by multiplying the average additional traffic of an airport project (i.e. the additional number of passengers that can be handled through the airport extension) by an average GHG emission factor per passenger. The average GHG emission factor per passenger is calculated as the weighted average scope 1 & 2 GHG emission factor of airports that report their scope 1 & 2 GHG emissions under the Airport Carbon Accreditation (ACA) scheme. EIB uses GHG emission factors for small and large airports, to account for the impact of scale increase (e.g. larger planes, etc.).

The ***scope 3 emissions from Landing and Takeoff (LTO) cycle (incl. engine run-up & testing, APUs etc.)*** *are* based on average GHG emission factors for the LTO and cruise cycle GHG emissions of the average flight operating from the airport. The GHG emission factors are expressed in g CO_2e emissions per passenger.

Relative GHG emissions:

The following calculation is used for relative GHG emissions for airports:

$$Relative\ GHG\ emissions =$$
$$+generated\ traffic\ GHG\ emissions - surface\ access\ GHG\ emission\ changes$$

$$with: generated\ traffic\ GHG\ emissions = generated\ \ GHG\ airport\ and\ flight\ emissions + generated\ hinterland\ GHG\ emissions$$

The ***generated traffic GHG emissions*** are the sum of *generated GHG airport and flight emissions* and *generated hinterland GHG emissions*[21]. The first step is to estimate generated demand, which is obtained from the Cost Benefit Analysis (CBA) model of the EIB[22]. GHG emissions from generated traffic are calculated by multiplying the generated demand (in number of passengers) with an emission factor. This emission factor includes scope 1, scope 2, LTO and cruise phases, all expressed in g CO_2e/passenger. To calculate the generated hinterland GHG emissions, generated traffic (in number of passengers) is multiplied by the average hinterland distance travelled to the airport per transport mode 11(the transport modes selectable are car and bus). This value is multiplied with an emission factor per transport mode in g CO_2e/pkm to calculate the generated hinterland GHG emissions.

The ***surface access GHG emission changes*** are calculated using data from the EIB's Cost Benefit Analysis (CBA) for airports. Firstly, the traffic to alternative airports being avoided due to transport distribution changes to/from the airport is estimated per transport mode in km (the transport modes selectable are car and bus). Then the distance is multiplied by an emission factor per transport mode in kg CO_2e/pkm to calculate the emission changes from surface access (i.e. surface access GHG emission changes).

[21] Hinterland emissions are those emissions that occur due to the transport of passenger to and from the airport, while generated hinterland emissions are those hinterland emissions that would not have happened without the new project (the baseline to compare with).

[22] The EIB's Cost Benefit Analysis for airports models the generated demand based on the generalised cost of travel and price elasticities of demand.

In following with standard carbon footprinting methodology, the measure of relative emissions excludes the effects of any carbon offsetting schemes that may apply to the project. In the case of EIB aviation projects, the schemes that most commonly apply are the EU Emissions Trading Scheme (ETS) and the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) of the United Nations (UN). This means that a project where ETS and/or CORSIA may apply shows the same relative footprint measure as if neither ETS nor CORSIA applied. In this case, the resulting relative carbon footprint is therefore incompatible with cost-benefit analysis.

Ports

Absolute GHG emissions:

EIB uses the following formula to calculate the average annual absolute GHG emissions for ports projects:

$$Absolute\ GHG\ emissions = Scope\ 1\ \&\ 2\ GHG\ emissions + Scope\ 3\ GHG\ emissions\ from\ \text{manoeuvring}\ and\ hoteling$$

The ***scope 1 & 2 GHG emissions*** are calculated by multiplying the average additional traffic (i.e. number of TEU for containers, tonnes, RORO-units or number of passengers) from a port project by an average GHG emission factor. The GHG emission factor is calculated based on available carbon footprints for scope 1&2 emissions of comparable facilities in the port if available or for comparable facilities in other ports publically available.

The ***Scope 3 GHG emissions from manoeuvring and hoteling*** are calculated multiplying the average additional traffic with the average manoeuvring and hoteling emission factors.

Relative GHG emissions:
EIB uses the following formula for the calculation of average annual relative GHG emissions for ports:

$$\begin{aligned} Relative\ GHG\ emissions = {} & generated\ traffic\ GHG\ emissions + hinterland\ GHG\ emission\ changes \\ & + shipping\ GHG\ emission\ changes + cargo\ handling\ GHG\ emission\ changes \end{aligned}$$

$$\begin{aligned} with\text{: } generated\ traffic\ GHG\ emissions & \\ = {} & generated\ shipping\ GHG\ emissions + generated\ hinterland\ GHG\ emissions \\ & + generated\ cargo\ handling\ GHG\ emissions\ (scope\ 1\ and\ 2\ GHG\ emissions) \end{aligned}$$

Handling GHG emission changes and generated cargo handling emissions are only taken into account if considered significant in the overall relative GHG emissions.[23]

The ***generated traffic GHG emissions*** are the sum of *generated shipping GHG emissions (including manoeuvring)*, *generated hinterland GHG emissions*[24] and *generated cargo handling (scope 1&2) GHG emissions* (if significant) To calculate these values, at first, the generated shipping demand needs to be obtained from the Cost Benefit Analysis (CBA) model of the EIB[25]. The generated shipping demand is measured in tonnes, TEU, RORO-freight units or number of passengers and multiplied with a GHG emission factor in g CO_2e/TEU (or tonnes or number of passengers or RORO units) to calculate the generated shipping GHG emissions.[26] This calculation assumes an average shipping distance for the project traffic.

[23] If significant in view of overall relative emissions
[24] Generated Hinterland emissions are emissions that occur due to the transport of generated traffic in the hinterland as a result of additional capacity and total transport cost reduction.
[25] The EIB's Cost Benefit Analysis for ports models the generated demand based on the generalised cost of transport and price elasticities of demand.
[26] It is important to note (as is also highlighted in the Word document on EIB's port methodology) that there is significant uncertainty regarding the different assumptions meaning that the results for the generated traffic emissions are only order of magnitude estimates.

The generated shipping demand in tonnes, TEU, RORO freight units or number of passengers is combined with the estimated average hinterland distance travelled to the port per transport mode to estimate the total generated hinterland transport in tkm, TEUkm or pkm (the transport modes selectable are road, rail and inland water way). This value is multiplied with a GHG emission factor in g CO_2e/tkm, g CO_2e/TEUkm or gCO_2/pkm to calculate the generated hinterland GHG emissions.

The ***hinterland GHG emission changes***[27] are calculated using data derived from the EIB's Cost Benefit Analysis CBA for ports. Firstly, the traffic to alternative ports being avoided due to transport distribution changes to/from the port is estimated per transport mode in unitkm. Then, the traffic in unitkm is multiplied with a GHG emission factor in g CO_2e/unitkm per transport mode to calculate the GHG emissions from hinterland transport changes.

The **shipping GHG emission changes** are calculated using data derived from the EIB's Cost Benefit Analysis CBA for ports. These changes are mentioned separately because they are not limited to the generated traffic. The impact of the project on the average GHG emission per tonne, TEU, RORO-unit or passenger as a result of scale increase or other efficiencies are thereby taken into account using different GHG emission factors for different average ship sizes calling at the project facilities in the with and without project scenario.

The **cargo handling GHG emission changes** are calculated using project specific data if the project leads to a significant change in cargo handling GHG emissions, e.g. when the project port terminal is operating significantly more efficient or less carbon intensive than the terminals in the without project scenario. As with shipping emissions, these changes are mentioned separately because they are not limited to the generated traffic.

[27] Hinterland emission changes are saved emission of avoided traffic diversion as a result of additional project capacity.

GLOSSARY

Absolute (Ab) GHG emissions. Annual emissions estimated for an average year of operation.

Baseline (Be) GHG emissions. The project baseline emissions arise from the expected alternative scenario that reasonably represents the anthropogenic emissions by sources of GHGs that would have occurred in the absence of the project, estimated for an average year of operation.

Carbon footprint. A carbon footprint is the climate impact (greenhouse gas emissions) of a project.

CFE. Carbon Footprint Exercise.

Direct GHG emissions. Fugitive, combustion or chemical processes related emissions from sources that are owned or controlled by the reporting company inside the project boundary. See Scope 1 emissions.

Emissions. The release of GHG into the atmosphere.

Emission factor. A factor allowing GHG emissions to be estimated from a unit of available activity data (e.g. tonnes of fuel consumed, tonnes of product produced) and gross GHG emissions.

ESDS. Environmental and Social Data Sheet.

Fugitive emissions. Emissions that are not physically controlled but result from the intentional or unintentional releases of GHGs. They commonly arise from the production, processing transmission storage and use of fuels and other chemicals, often through joints, seals, packing, gaskets, etc.

Greenhouse gases (GHG). GHGs are the seven gases listed in the Kyoto Protocol: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6); and nitrogen trifluoride (NF_3).

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 over a given period of time.

Indirect GHG emissions. Emissions that are a consequence of the operations of the project, but occur at sources owned or controlled by another company e.g. purchased electricity. See Scope 2 and Scope 3 emissions.

Process emissions. Emissions generated from manufacturing processes, such as the CO_2 that arises from the breakdown of calcium carbonate ($CaCO_3$) during cement manufacture

Project boundaries. The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the project. This assessment allows a project developer (investor) to establish which operations and sources cause direct and indirect emissions, and to decide which indirect emissions to include that are a consequence of the project operations

Relative emissions. The difference (delta) between the absolute project emissions and the baseline scenario emissions.

Typical year of operation. In calculating the absolute or relative emissions of a project, a typical year of operation is used in which the project operates at normal capacity. This means excluding emissions from construction or decommissioning and unexpected outages and maintenance activities. In many cases, it is the average year over the lifetime of the project.