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Guidance Note: Greenhouse Gas Accounting for Energy Investment Operations

Transmission and Distribution Projects

Power Generation Projects

and Some Demand-Side, Energy-Efficiency Activities

Version 1.0

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The World Bank's Sustainable Energy Department

In collaboration with

The Water Unit of the Transport, Water, and Information and Communications Department

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Acronyms and Abbreviations

AFOLU	Agriculture, Forestry and Other Land Use (common name for the 2006 IPCC Guidelines for National Greenhouse Gas Inventories)
BS	Barrier screening
Btu	British thermal units
CCGT	Combined-cycle gas turbine
CDM	Clean Development Mechanism
CFL	Compact fluorescent lamp
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
EF	Emission factor
EIA	Environmental Impact Assessment
FY	Fiscal year
gCO_2	Grams of carbon dioxide
GEF	Global Environmental Facility
GHG	Greenhouse gas
GJ	Gigajoule
GWh	Gigawatt-hour
ha	Hectare
HFO	Heavy fuel oil
IFI	International financial institutions
IPCC	Intergovernmental Panel on Climate Change
$kgCO_2$	Kilograms of carbon dioxide
km	Kilometer
km^2	Square kilometer
$KtCO_2$	Thousand tons of carbon dioxide
kV	Kilovolt
kWh	Kilowatt-hour
LF	Loss factor
m	Meter
MW	Megawatt
MWh	Megawatt-hour
MVA	Megavolt amperes
NE	Net emissions
PAD	Project Appraisal Document
SF_6	Sulfur hexafluoride
SFDCC	Strategic Framework for Development and Climate Change
T&D	Transmission and distribution
t	Metric tons
tCO_2	Metric tons of CO_2
tCO_2e	Metric tons of CO_2 equivalent
tSF_6	Metric tons of SF_6
TL	Technical losses
WBG	World Bank Group

1. Background and Introduction

The Strategic Framework for Development and Climate Change (SFDCC), endorsed in October 2008, committed the World Bank Group (WBG) to selecting pilot projects in energy, transport, and forestry on a demand basis to undertake greenhouse gas (GHG) assessment, focusing on net emissions, as part of a broader analysis of all project benefits and external costs. The WBG's Environment Strategy, endorsed by the Board of Executive Directors in 2012, expanded this commitment to begin conducting GHG emissions analysis for all energy, transport, and forestry projects that have agreed methodologies and tools, and envisaged a two-year phase-in period for assessing the GHG emissions of investment lending operations as a WBG business requirement.

The International Finance Corporation (IFC), given the nature of its work and client base, has been using a tool (Carbon Emissions Estimator Tool) that is more focused on gross emissions for all real-sector investments since 2009, consistent with the reporting required under its Performance Standards and with voluntary carbon disclosure reporting registries commonly used by the private sector. Use of this tool has enabled the IFC to collect core data and integrate this work into the project cycle. Since fiscal year (FY) 2012, IFC has been assessing the GHG reductions of its climate-related projects on a net basis, using an approach based on definitions, methodologies, and tools developed within IFC in consultation with other multilateral financial institutions.

This guidance note is for World Bank staff and responds to the corporate commitment made by the WBG to undertake GHG emissions accounting for investment projects in the energy sector beginning in July 2013. This note is designed to provide guidance on the key principles and methodologies involved in GHG accounting.

This corporate requirement does not affect projects supported by any form of carbon financing, which are already required to carry out GHG emissions accounting. Such projects will continue to follow the approved methodologies, such as the Clean Development Mechanism (CDM) methodologies for CDM projects or the appropriate guidelines of the Global Environmental Facility (GEF). Furthermore, in cases where the World Bank is providing co- or parallel financing for a CDM- or GEF-registered project, the the corresponding CDM or GEF methodologies should be used to fulfill the WBG's GHG accounting requirement.

1.1 Introduction

The main objective of GHG accounting at the project level is to respond to the WBG corporate commitment to understand the "GHG footprint" of its portfolio better. GHG accounting at the project level does not have the objective of influencing decisions about project selection and these should continue to follow current World Bank policies.

This corporate requirement will be rolled out over two years, and all investment projects in the energy sector meeting certain criteria will be covered by June 2015. Initially, starting in July 2013, GHG emissions accounting for the energy sector will be carried out for power generation projects, transmission and distribution (T&D) projects, and a limited subset of demand-side, energy-efficiency projects using grid-connected electricity, all of which are the subject of this guidance note. Because of several unique features specific to hydropower projects, they are treated separately from the rest of generation projects in this note. Some sub-categories of projects are excluded from the categories covered in this version of the guidance note, such as pumped storage hydropower and power generation from biomass combustion, for which further methodology development is still required. These exclusions are indicated in the methodology sections.

This document, intended to help teams start conducting GHG emissions accounting for the categories of projects covered by it, represents the first version (Version 1.0) of the guidance note. It is not a static document, but may be modified with experience and expanded as new methodologies are developed. Experience with World Bank projects as well as the evolution over time of methodologies at other international financial institutions (IFIs) will both inform the future modification and expansion of the guidance note. The methodologies in the guidance note will therefore be reviewed periodically and revised, as necessary, when more experience is gained and as additional data become available from the first two years of implementation, and in accordance with the WBG's evolving business needs. Any updates to the current guidance note or addition of a new project category will be communicated to the energy practice.

The principal elements and guiding principles underlying GHG accounting are summarized as follows:

The GHG emissions accounting will be carried out at the time of project appraisal to ***gain a better understanding*** *of the GHG emissions of the WBG-financed projects* ***relative to*** *credible baselines*. While the WBG recognizes that a project has multiple costs (financial, economic, social, and environmental) and benefits (quality of life, economic, public safety, health, education, environmental, and social), the intention of GHG accounting is to focus only on GHG emissions. Relative emissions, or net emissions accounting, will be performed for all projects. As illustrated by examples in this guidance note, in some cases net emissions can be computed directly. For many, if not most, other cases, however, gross emissions need to be estimated first for the project and the baseline before arriving at net emissions.

The World Bank's GHG accounting aims to apply user-friendly, simplified methodologies that follow well-established principles and that capture the most important emissions. Comprehensive life-cycle GHG analysis requires considerable information and can be resource-intensive. In view of these constraints, GHG analysis would apply a simplified standardized methodology that captures the most important emissions from projects during project preparation and is relevant to the main objective of the mandate—which is to understand the "GHG footprint" of the WBG-wide portfolio.

Ensuring completeness, comparability, transparency, and ease of implementation. The methodologies consider the following important aspects: consistency to allow meaningful comparison of emissions within the same project over time and across different projects; disclosure of assumptions and documents, a relationship with other methodologies that have been adopted, and data sources used; avoiding overburdening the project teams by selecting, to the extent possible, the least data- and calculation-intensive means, without compromising the integrity of the estimated emissions that lead to systematic over- or underestimation of GHG emissions; and ensuring reasonable assurance of accuracy, while minimizing uncertainties as far as practicable.

Focusing on the most significant impacts. With the understanding that, globally, most significant emissions from the energy sector come from fuel combustion, the note places a special emphasis on capturing these impacts and others of considerable magnitude in the energy sector (such as land clearing) that can be reasonably reliably estimated during project appraisal. Other upstream emissions, such as manufacturing of materials, are generally less important in magnitude for the energy sector, and it is not always feasible to estimate them at the time of project appraisal. Policy lending and stand-alone technical assistance support are not covered. However, if the WBG contribution to an investment operation is a technical assistance component (grant or lending), without which the investment operation would not otherwise proceed (for example, an environmental management component), the investment project will be subject to the corporate requirement of GHG accounting. For any investment project, emissions for the entire project will be computed and not be apportioned based only on the WBG's contribution.

1.2 Project Boundaries

The boundaries defining the coverage of emissions are described in more detail in the chapters on different project categories. An important concept in delineating the project boundaries is that of scopes of emissions in projects as defined by the GHG Protocol,[1] which the WBG has adopted:

- **Scope 1** emissions are direct emissions from sources that the project owns or controls, such as emissions from combustion in boilers or furnaces.
- **Scope 2** emissions are those associated with purchased electricity, steam, heating, or cooling necessary for the operations of the project. These are also called indirect emissions.
- **Scope 3** emissions are all indirect emissions other than those covered by Scope 2. They are a consequence of the activities associated with the project, but occur from sources not owned or controlled by the project. Examples of Scope 3 activities include extraction and production of purchased materials, transport of purchased fuels, and downstream emissions from use of products and services sold by the project.

With regard to Scope 3 emissions (for which GHG accounting is optional in the GHG protocol), the IFI harmonization framework (see 1.3 below) also allows for flexibility over whether to include them in GHG accounting, requiring inclusion of Scope 3 emissions primarily in sectors where such emissions have been identified as an issue. Because of the difficulties in identifying such project categories and proposing a methodology for systematic inclusion of Scope 3 emissions, this version of guidance does not require computation of Scope 3 emissions. They are optional and the whether to compute them will be assessed on a case by case basis. Further work will be carried out to understand when Scope 3

[1] World Business Council for Sustainable Development and World Resources Institute. 2004. *GHG Protocol: A corporate accounting and reporting standard. Revised edition.* Geneva. http://pdf.wri.org/ghg_protocol_2004.pdf.

emissions can be considerable and need to be included in project accounting, provided they can be reliably computed during project appraisal.

1.3 Harmonization

Harmonization with widely accepted methodologies. The simplified methodologies have been developed to maintain consistency with widely accepted methodologies and procedures in the international community whenever feasible (for example, the concept of combined or grid emission factors to model emissions from alternatives to renewable power generation). This will help ensure that while differences in the estimation could continue to exist, the orders of magnitude of the estimates remain consistent.

Harmonization with other multilateral development banks. For the past several years, efforts have been made to harmonize GHG emissions accounting across multilateral development banks. A group of IFIs issued a document outlining a harmonization framework in January 2013.[2] The harmonization agreement includes, among others, the following aspects that were taken into account while developing this guidance note:

- Each institution shall publicly state its commitment to accounting for the GHG emissions of the direct investment projects it finances.
- Each institution may establish de minimis criteria for GHG screening, and will undertake GHG emissions accounting of all direct investment projects consistent with the criteria.
- Each institution will estimate the gross GHG emissions that a project is expected to produce on an annual basis for a representative year once it is complete and at normal operating capacity.
- For both gross and net emissions, each institution will account for all Scope 1 and Scope 2 emissions, and may also choose to include Scope 3 emissions. Leakage in Scope 3 emissions should be included in sectors where this is identified as an issue.
- In order to capture the development and mitigation contribution of projects, *net (or relative) GHG emissions* against a *baseline* will be assessed on an annual basis. The baseline analysis may be either a "without project" scenario or an "alternative scenario" that reflects the most likely alternative means to achieve the same project outcomes or level of service.
- At a minimum, each institution shall report annually on the aggregate net GHG emissions for mitigation projects estimated to arise from the previous year's approved investments. Each project will be reported only once during the year of approval.

1.4 Baseline Scenario for Net Accounting

The baseline scenario is defined as the most likely alternative to the project that provides energy services of comparable quality, properties, and applications. For the purpose of GHG emissions accounting, the baseline is always different from the project itself, so that net emissions are not identical to zero. The baseline is also typically not a no-project case; the principle followed is to fix the

[2] "International Financial Institution Framework for a Harmonised Approach to Greenhouse Gas Accounting." https://www.nib.int/filebank/a/1358516702/86247517d51b1706d7963cecbe5421ea/2792-IFI_CO2_framework.pdf.

outputs of the project and seek different means of providing the same output within a comparable timeframe. However, in projects in which the primary objective is to reduce technical losses in T&D, reduce SF_6 leakage, or increase demand-side energy efficiency, the baseline could be a no-project scenario.

Comparing the service of one project to another will entail some judgment and will depend on each specific type of intervention. The note provides guidance to teams on determining the baseline for different types of interventions (T&D, generation, and demand-side efficiency improvement). Because it is not possible to anticipate all future project conditions, the classification of baselines in this note should not be regarded as being exhaustive. As more experience is gained and more specific cases not falling under any of the categories in this version of the guidance note are encountered, additional baseline cases will be added.

In general, the most likely alternative is the next most feasible project, set of projects, or response[3] that provides the same level of service. The feasibility of the alternative takes into account all technical, economic, financial, and legal or regulatory factors and country conditions. Identifying the baseline will require an expert judgment from the team preparing the project. Teams are better positioned to assess the barriers faced by alternatives to the project and select the most likely alternative to the project under consideration. Specific guidance for each type of project, following the stated principles, is provided in this initial guidance note.

1.5 Timeline and de Minimis Criteria

Timeline of GHG accounting. In the energy sector, the timeline for emissions accounting is the economic life of the project. This can be considered the period over which it is prudent to continue using the most important (which is typically the most costly) component or asset of the project. The economic life never exceeds the physical life of the asset.

If the economic life of the project in the baseline scenario is shorter than that of the project, the alternative scenario must consist of more than one project: a first project that will end before the economic life of the original project, a second project that will start at the end of the first alternative project, and so on, until the end of the life of the original project is reached.

One exception is hydropower reservoirs, for which the current state of science suggests that it would not be possible to estimate biochemically generated emissions from the reservoir for less than the full lifetime of the dam infrastructure, defined by the Intergovernmental Panel on Climate Change (IPCC) as 100 years. The major civil structures in a hydropower project (such as dams, tunnels, and powerhouses) have a life span in the range of 100 years or longer, provided they are properly maintained. Turbines, hydraulic steelworks, and other items of machinery have a life span of 30−50 years, and smaller pieces of equipment such as breakers and control equipment have a life span of 10−20 years. As the chapter on

[3] It should be noted that the alternative is not necessarily a project; it could be a combination of several projects or a response from various actors (for example, use of various on-site diesel generators in the absence of cost-effective and reliable electricity from a grid).

hydropower explains, where the project life is 100 years, the emissions associated with generation in the baseline are not calculated for 100 years; they are instead calculated for the life of the alternative generation technologies. This is a conservative approach that would significantly under-estimate net reductions in lifetime emissions if the alternatives are based on fossil fuels, because the generation emissions in the baseline are effectively set equal to zero between the end of the life of the baseline generation plant(s) and 100 years.

In the case of a hydropower rehabilitation project supported by the World Bank, which prolongs the life of an existing hydropower plant located at a dam, net reservoir emissions are set equal to zero. The rationale is that emissions during the full lifetime of the reservoir occur largely during the economic life of the equipment installed initially, and any residual emissions occurring after rehabilitation would be very small.

The focus of GHG emissions accounting in the World Bank's energy sector is on lifetime emissions. However, the harmonization agreement among IFIs commits each institution to estimate gross emissions, subject to de minimis criteria below, for a representative year of operation in addition.

De minimis criteria. In order to balance ease of implementation with completeness, not all projects in the categories covered in this guidance note need to undergo GHG accounting or calculate gross emissions. Where it is not necessary to calculate gross emissions to arrive at net emissions, gross emissions will not be computed. For all generation projects, it is proposed that GHG emissions accounting be performed regardless of project size. Generation projects have the largest impact on emissions in the energy sector. The impact could be either increases or reductions in GHG emissions, depending on the project. In this note, only T&D projects have threshold values below which it is not necessary to compute emissions, as descripted in section 2.4 in the next chapter.

The next four chapters provide guidance for the categories of projects initially covered under the GHG accounting requirement. They are any greenfield and brownfield generation projects except those burning biomass, with chapter 2 covering all generation other than hydropower and chapter 3 covering hydropower; T&D projects in chapter 4; and some demand-side, energy-efficiency interventions in chapter 5. All the specific guidance chapters are self-contained. Teams can consult the respective sections to guide their GHG calculations.

2. Transmission and Distribution Projects

While this is a stand-alone chapter on transmission and distribution, it is recommended that the main concepts and principles found in the first chapter be reviewed in addition as well.

2.1 Typology of T&D Projects

World Bank T&D projects are associated with building new or refurbishing T&D equipment. The objectives of these projects in World Bank interventions typically include expanding the capacity of the T&D grids, improving reliability, reducing losses, and connecting grids to access or improve the utilization of generation resources across borders. Interventions usually include various components, each component will usually have a different geographical area in the network, and its objective may be related to one or more of the following categories:

- *New network expansion* projects involve increasing the overall capacity to transmit electricity so that additional power generation can reach different areas of the transmission system, such as distribution centers or new consumers connected to the grid.
- *Loss reduction* projects reduce technical losses in the transmission and/or distribution system, so that less electricity is lost between power generation and end users. The electricity previously lost during T&D enables less power generation to meet the same demand.
- *Reliability* projects improve electricity grid reliability, with the final objective of improving the service provided to final consumers by reducing the number, duration, and severity of interruptions.
- *Electricity trade or system interconnection* projects increase electricity trade between countries or regions within a country by constructing interconnectors between major grids.
- *Small isolated grid* projects increase access by means of mini-grid schemes. They may involve constructing a few hundred meters up to a few kilometers of distribution-level voltage grids.

This guidance note covers only the first four categories of projects, and they are subject to the GHG accounting requirement beginning in July 2013. Methodologies will be further developed to cover small, isolated grids.

2.2 Project Boundaries

During the operation of the project, emissions that occur inside the physical boundaries of the T&D facilities being supported by the project will be considered or emissions outside the boundaries that are in Scope 2 (for example, losses). While all of the foregoing project categories affect power generation and the GHG emissions associated with it, emissions from power generation are not considered under T&D because they are outside the project boundaries and because the transmission infrastructure operations do not influence the emissions associated with generation. The only exception is losses, over which the project has control and which are a natural consequence of the project (Scope 2). Most of the emissions associated with manufacturing equipment will occur outside the physical boundaries of the project and they would be difficult to estimate during the World Bank's project appraisal cycle, because the manufacturing origin is known only after project procurement.

Emissions can be further divided into one-time and lifetime or concurrent emissions. One-time emissions have three sources: land clearing needed for T&D right of way, emissions from manufacturing the material and equipment used by the T&D facilities, and emissions from construction of the T&D facilities. Concurrent emissions include leakage from equipment that uses sulfur hexafluoride (SF_6) and emissions associated with generation of electricity lost in the physical boundaries of the project.

2.3 Sources of Emissions

Five sources of emissions are considered and listed in order of relative decreasing importance and in congruence with the scopes applicable in the corporate mandate. Computing the impacts of the first three categories is mandatory. Although some activities in category 5 may belong to Scope 2, computation is not required for the last two for two reasons. First, categories 4 and 5 have relatively minimal impact compared to land clearing and SF_6 fugitive emissions (Scope 1) or losses (Scope 2). Second, computation during project appraisal is generally not feasible.[4] Beyond losses,[5] other impacts on generation emissions (Scope 3), such as changes in generation use patterns[6] that are not directly controlled by the T&D infrastructure intervention, are not considered part of the project boundaries.

The following three categories of emission are the most significant for T&D projects and they must be considered in project GHG accounting:

1. *Direct generation emissions associated with losses.* Impacts result from technical loss reductions or increases within the boundaries of the T&D facilities being supported by the project. Losses can be reduced by upgrading overloaded or not properly sized transformers, increasing conductor capacity, installing reactive power equipment, and other types of maintenance interventions. When pursued directly,[7] the magnitude of these emissions is highly likely to be much larger than the rest of the sources of emission from T&D interventions.

2. Land clearing. New construction of long-distance lines, or even of distribution lines and substations, may affect carbon stored in biomass and soil. Depending on the circumstances, land clearing could account for the largest fraction of total gross emissions within the project boundaries. An obvious example would be clearing a forest for a long-distance transmission line, which would result in a one-time release of the carbon stored in the vegetation. This impact would be common for new transmission investments in areas with high forest cover, and possibly for electrification and distribution projects that involve new feeder lines, but is unlikely to be important for upgrading T&D equipment to reduce losses and increase reliability. Some of the biomass would grow back after line construction, although the amount and density would depend on the climate and maintenance procedures for the line, as well as on how high the line is.

[4] The emissions from manufacturing materials for T&D lines will depend crucially on the country where they are manufactured and the processes used. Such information generally becomes available only during project execution, which happens after project appraisal. In addition, computing these emissions for the baseline (which can be one or several projects) would be highly subjective.

[5] Losses can be considered an unavoidable “use” of energy by the T&D lines and a consequence of the natural response of material to electricity flows.

[6] Such as changes in dispatch or the displacement of fuels after interconnecting systems.

[7] A T&D project may have the main purpose of improving reliability and indirectly reducing losses. In such cases, if loss reductions are clearly documented, the impacts in emissions can also be accounted.

3. Sulfur hexafluoride fugitive emissions. SF_6 is used in insulation and current interruption applications in T&D systems.[8] SF_6 is used in gas-insulated switch-gear and substations, gas circuit breakers, and (less frequently) in high-voltage, gas-insulated lines. SF_6 may escape as fugitive emissions during the manufacturing, installation, use, maintenance, and disposal of this equipment. Sealed distribution equipment may not emit any SF_6 during use, but transmission equipment often requires periodic refilling and hence has higher fugitive emissions during use. The amount of SF_6 emitted during operation and decommissioning is related to the number and type of equipment used, as well as the maintenance and recycling procedures. SF_6 emissions could occur in all T&D projects, depending on the type of equipment installed, refurbished, or maintained. Countries report SF_6 emissions from the power sector in their national emissions inventories, and emission factors from these inventories provide one approach for estimating their magnitude. If national inventories are not available, some industry leaking factors, if available, may be used, as described later in this guidance note.

Including the following sources of emissions is optional:

4. Embodied emissions in construction materials. The construction of T&D project facilities consumes large quantities of aluminum, other metals, concrete, and other building materials. All these materials have embodied emissions as a result of the energy used to produce them, meaning that the implementation of new T&D projects creates some upstream emissions in the manufacture of the materials used. Besides the fact that these emissions are expected to be low, estimating such emissions would require knowing ex ante the place where the equipment is manufactured, which is not known until the closure of procurement for the project, and the method of manufacture.

5. Energy use in construction. Energy is used in the construction of a T&D project facility, primarily in the form of transport fuel for construction vehicles and the shipping of components. As with embodied emissions, computation of emissions associated with energy use during construction is optional.

2.4 Screening Threshold for Accounting Projects

Given that World Bank projects that support T&D investment can have many components supporting different areas of the electricity network in a country and different objectives (for example, a grid expansion component, a grid reinforcement component, and others), performing GHG accounting can become overly burdensome if all components need to undergo GHG accounting. Since emissions from T&D are insignificant compared to those in the energy sector as a whole (except for losses and land-clearing impacts that could be large in some contexts), not all project components in T&D projects will need to perform GHG accounting.

Thresholds for gross and net emissions are established below which T&D project components are not required to perform GHG accounting. The main objective of the threshold value is to balance between completeness and ease of implementation of the corporate mandate on GHG accounting; only project components exceeding the threshold value for gross (if gross emissions are computed) or net are subject to the mandate. Following the thresholds established by other IFIs, project components with estimated annualized gross emissions above 100,000 tCO_2e will be required to undergo GHG accounting.

[8] IPCC (Intergovernmental Panel on Climate Change). 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories.* Geneva. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

As noted below, this threshold will most likely be reached by project components that include high-voltage transmission projects that need to clear more than 35 kilometers (km) or a right of way of 60 meters (m), or for projects with annual T&D losses of about 125,000 megawatt-hours (MWh) per year. For net emissions, the *absolute value* of the threshold is 20,000 tCO_2e.

Based on conservative land-clearing estimates using the highest biomass density (such as for a tropical rainforest), a project with a total of at least 35 km of transmission lines (with a 60 m right of way) will exceed 100,000 tCO_2e per year. Therefore, if a project component involves less than 35 km of transmission lines in total, GHG accounting will not be necessary. If a project exceeds the 35 km threshold, the land-clearing module (see Annex 2A) should be used to determine whether the project needs to undergo the GHG accounting exercise. Annex 2A explains a straightforward process for estimating land-clearing emissions. Emissions from projects that rehabilitate and upgrade existing lines (without the need to clear new land), especially distribution, are most unlikely to be above the threshold and hence it will not be necessary to perform GHG accounting. Similarly, emissions from small distribution-level grid extensions involving only a few kilometers of transmission lines or little land clearing are unlikely to exceed the threshold. Project components for new, large (above 35 km) high-voltage transmission and substations will most likely be above the threshold. Losses will be another important factor to determine if the threshold is exceeded. Any T&D projects with estimated annual total losses exceeding 125,000 MWh will lead to gross emissions close to or above 100,000 tCO_2e (for grid emission factors above 0.8 tCO_2e/MWh). If the losses or the amount of land clearing indicate that the project component may have emissions exceeding 100,000 tCO_2e a year, teams should estimate GHG emissions following the guidelines in this chapter.

2.5 Computing Net Emissions

Net emissions are calculated as the difference between project and baseline emissions. The example in Table 2.1 illustrates a case in which net emissions are calculated directly without computing gross emissions first; the losses shown represent the difference between the project and baseline cases, and are not intended to suggest that the project will eliminate all losses, which is not physically possible.

Table 2.1: Example net emission calculation for a T&D project ($tC0_2e$)

	Baseline	**Project**	**Net**
Land clearing	0	0	0
SF_6	0	0	0
Embodied emissions	0	0	0
Energy in construction	0	0	0
Generation emissions from T&D losses	570,988	0	-570,988
Total emissions over 10 years	570,988	0	-570,988
Annual emissions	57,099		-57,099

Note: The numbers are from Table 2B.1 in Annex 2B and are for illustrative purposes only. This table could represent a network expansion project, the identified alternative of which is similar in length and needed infrastructure (leading to the same upstream emissions), but has slightly higher losses.

Because the absolute value of the annual net emissions exceeds 20,000, this project is subject to the corporate requirement for GHG emissions accounting.

2.6 Defining the Baseline

The baseline, or alternative, to the project intervention, is usually not "no project" but rather a project that provides the same level of service (for example, same transmission capacity or reliability level) provided by the project being pursued. Two exceptions are projects components in which the primary objective is reducing losses or SF_6 emissions and alternative means of reduction are not examined during project preparation. In such cases, the alternative is likely to be a no-project scenario with continuation of the current level of losses or emissions, respectively. Otherwise the baseline would be the next most likely project from all feasibility angles (economic, technical, financial, and regulatory, considering specific country conditions). Table 2.2 provides a guideline for the baseline for each type of T&D project objectives[9] being considered.

In some cases, detailed in Table 2.2, the baseline is a very low-emissions benchmark (referred to as the high-efficiency benchmark hereafter)—at the efficiency frontier of a well-performing T&D grid having minimal technical losses and using very conservative assumptions of zero emissions associated with both land clearing and SF_6 leakage. For the purpose of this guidance note, this benchmark is a highly efficient transmission system with a 2 percent technical loss, sub-transmission losses of another 2 percent, and distribution losses of 3 percent, representing total losses of 7 percent.

If SF_6-containing units are not specifically identified in the most likely alternative identified, SF_6 emissions are set equal to zero, corresponding to those in the high-efficiency benchmark. The one exception is a project component for which the primary objective is reducing SF_6 emissions (see Table 2.2).

Table 2.2: Transmission and distribution project types and baselines

Project Objective	Baseline
New network expansion	There are two most likely alternatives to a T&D expansion. The first is a different expansion and/or rehabilitation that delivers the same results, but requires different routing (typically for environmental reasons) to achieve the same capacity expansion. The emissions of such an alternative will likely be very similar to those of the project. The second is a different configuration (which may consist of different voltages, line routes and lengths, and substation locations). In both cases, the alternative so identified should be used to compute the baseline emissions. If no alternative is identified as part of the economic analysis, the baseline emissions will be considered very low to keep the estimate for net emissions on the conservative side. In such cases, the alternative is the high-efficiency benchmark described above. In some cases, the alternative could be to use local or distributed generation. The generation

[9] It should be noted that T&D projects are generally a collection of interconnected infrastructure additions (for example, a line, receiving substations, and other line segments to integrate the upgrade to or expansion of the grid), the objective of which is to achieve certain goals in the grid. Interventions may have more than one goal, such as reducing losses and increasing capacity.

Project Objective	Baseline
	emissions from such alternatives, however, are outside the accounting boundaries. Whether these generation sources have higher or lower emissions than the grid, they are not considered for the purposes of GHG accounting of this corporate mandate, because these emissions are not the exclusive result—and a direct consequence—of the transmission infrastructure itself. The difference between the project and baseline emissions would be the difference in emission from the two T&D systems associated with the baseline and the project. A distributed generation alternative would likely require less T&D infrastructure and have lower emissions from T&D.
Reducing technical losses	In T&D project components with technical loss reduction as the primary objective, alternatives may be specifically identified to reduce losses (for example, resizing conductors versus replacing transformers and/or adding reactive compensation). If such alternatives have been identified, they should be used as the baseline. For emissions associated with land clearing and SF_6, project and baseline emissions will likely be very similar, but if the alternative has been identified in specific terms, these emissions should be estimated separately for the baseline. If alternative means of reducing losses have not been studied, the most likely alternative is the continuation of the current situation, whereby the existing technical losses continue to increase in the absence of investments, requiring more generation to be injected into the grid to continue providing the same level of service to the final consumer. This would most likely be the situation with distribution utilities in technical and financial distress. Computing net emissions in these cases may not require computing gross emissions from the project and the baseline, since net emissions can be computed directly. SF_6 emissions in the baseline are those in the high-efficiency benchmark, namely zero. In project components in which the primary objective is one other than loss reduction (any of the other objectives in this table), if no specific alternative for loss reduction has been identified, for the purposes of computing net emissions, the high-efficiency benchmark as described above should be used.
Improving reliability	The most likely alternative for achieving the desired reliability improvement will be a different set of interventions in T&D infrastructure, the emissions of which may be comparable to those of the project. The identified alternative should be used as the baseline. If no alternative is identified as part of the economic analysis, the baseline emissions will be considered very low to keep the estimate for net emissions on the conservative side. In such cases, the alternative is the high-efficiency benchmark described above. As with network expansion, local or distributed small grids with small-scale generation could also be an alternative. If such an alternative has been identified as the most likely option, it should be used as the baseline. The emissions from generation of the distributed sources (whether they are higher or lower than the grid) are not counted in the emissions of the T&D project.
Electricity trade or system inter-connections	For projects that span borders (or different systems), the most likely alternative is to continue increasing the generation and investing in more generation within each separate system, which may in turn require additional transmission investments. Although interconnections can enable the reduction in emissions by changing the patterns of generation dispatch, they will not, in most cases, be a direct result of the T&D infrastructure project intervention only;[10] such a change in

[10] Facilitating trade across borders requires—beyond the infrastructure—additional institutional, policy, and regulatory actions to set up the legal and commercial framework that enables cross-border trade, plus other financing and regulatory actions that are needed to ensure that generation is available and traded (in various

Project Objective	Baseline
	generation occurs outside the boundaries of the project. An interconnection can also have impacts on losses; if their estimation is properly documented, its impact on emissions should be considered, utilizing the guidance in this note. Other emissions, such as those from land clearing, SF_6, and construction of the alternative to the interconnection, could be lower or higher depending on the alternative. The alternative could have lower emissions, especially if the transmission line required to source local resources is shorter or clears less carbon-intensive vegetation. When the T&D intervention is interconnecting two subsystems of a system that is operated as a unity, changes in generation needs or the dispatch mix could reduce emissions as soon as the interconnection is added. These emissions are nevertheless not considered for the purposes of the corporate GHG mandate, because the reduction in emissions cannot be attributed solely to the T&D intervention.
Reducing emissions from SF_6-emitting equipment	If the SF_6 emissions reduction is the primary objective of a project component, other alternatives may be examined, involving a specific strategy to reduce the SF_6 content by focusing on certain equipment, such as breakers or encapsulated substations. If such alternatives have been identified as the most likely to achieve the same objective (such as breaking capacity or substation capacity), they should be used as the baseline. If alternatives have not been studied, then the most likely alternative scenario is continuing use of older equipment with higher SF_6 leakage emissions, which provides the same level of service. In this case, baseline emissions will be higher than project emissions. In some instances, only the relative emissions from replacing old with new SF_6 equipment may be known, in which case the gross emissions of the project or baseline do not necessarily need to be calculated. In cases where reducing SF_6 emissions is the primary objective, the boundaries for the project component consist of SF_6-containing units only. Emissions associated with T&D losses will not be part of the GHG emissions accounting.

2.7 Indicative Emissions Patterns

Table 2.3 shows the most likely or typical outcomes of incremental emissions from various types of T&D interventions.

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formats, such as bilateral, spot, or other forms of trading) across borders. This version of the guidance note covers only GHG impacts that can be directly attributed to the physical infrastructure interventions (the “hard actions”). As more knowledge is gained, additional guidance may be developed in the future to categorize and allocate emissions from project interventions not covered in this version of the guidance note, including the associated “soft” measures, such as institutional, regulatory, and other forms of support beyond the transmission investments—including those required to make generation available for trade across or within borders—that are required to facilitate trade in each particular circumstance.

Table 2.3: Indicative emission patterns T&D projects

Project objective	Most likely overall net emissions impact
New network expansion	Neutral (0) or higher emissions (+) if the alternative requires fewer transmission facilities (e.g. less land clearing and SF_6)
Reducing technical losses	Reduction (-)
Improving reliability	Neutral (0) or higher emissions (+) if the alternative requires fewer transmission facilities (e.g. less land clearing and SF_6)
Electricity trade or system interconnections	Neutral (0) or lower emissions (-) if the alternative requires more transmission facilities (e.g. more land clearing for an alternating current interconnection compared to a direct current interconnection)
Reducing SF_6-emitting equipment	Reduction (-)

It should be noted that one project can include multiple components, for example, network expansion and reducing technical losses. If estimated emissions of a component are above the threshold described in section 2.3, it is recommended that emission be computed independently for each component, provided it has a clearly defined boundary and has already been analyzed independently (e.g. from the technical or economic perspective) from other components. Reducing technical losses and SF_6 emissions will typically be the only means of reducing emissions from the baseline scenario in T&D projects. Technical loss reduction projects will reduce emissions in the corresponding generation. While that generation occurs outside the project boundaries, the project has complete control over the amount of generation avoided to deliver the same amount of electricity as before the project, and hence the avoided emissions are counted in the T&D emissions accounting. SF_6-targeting project components will reduce emissions within the direct boundaries.

Annexes 2A and 2B to this note have an extended manual of the GHG calculation tool for T&D projects. Annex 2B includes examples of the application of the guidance in this chapter.

Annex 2A: Manual: T&D Emission Calculation Tool

This manual describes a tool that teams can use to assist their GHG calculations for T&D projects following the principles and concepts presented in chapter 2 of this document. The tool is an Excel workbook with various tabs to assist in the process, but its use is not mandatory. Teams can perform calculations using their own models and tools or their consultants' tools, as long as the guidance is followed. The steps to compute GHG emission for the project and baselines using the tools can be summarized as follows:

Step 1. Calculate direct generation emissions associated with T&D losses.

Step 2. Calculate land-clearing emissions.

Step 3. Calculate SF_6 emissions.

Step 4. Calculate embodied emissions in construction materials (optional).

Step 5. Calculate emissions from energy use in construction (optional).

- Important conventions in the Excel workbook developed for this guidance note:[11]
  - Cells shaded in yellow are inputs, to be adjusted by the user.
  - Cells shaded in blue are formulas or references, but can be adjusted manually by the user.

Each step is implemented as follows:

Step 1. Calculate avoided generation emissions associated with reduced losses.

- Open the workbook and go to "T&D Emissions Calculator" sheet. The purpose of the sheet is to compute emissions that result from generation that will be consumed as losses in the T&D equipment—which will be referred simply as technical losses (TL) in the next equations. The emissions will be proportional to the amount of losses (MWh) and the emission factors from the generation technologies in the system. Losses can be accurately determined with power system models (load flows). In their absence, a simplified emission factor procedure can be used as presented in the option diagram in Figure 2A.1.
- The following decision tree should be used for choosing which modules to select for calculating generation emissions associated with reduced losses, where BE is baseline emissions, PE is project emissions, EF is an emission factor, and TL_{BL} and TL_{PJ} are the technical losses from the baseline and the project, respectively:

[11] Workbook in Excel, "WB Emissions Estimation Tool.xlsm."

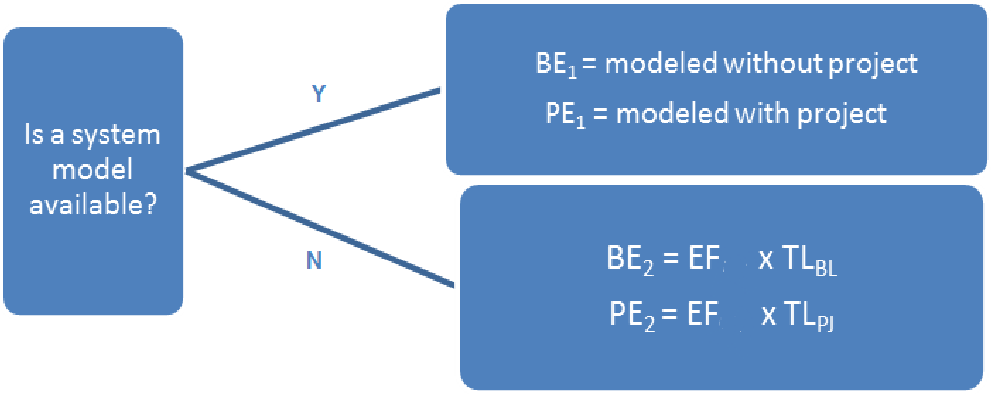

Figure 2A.1: Alternatives for computing emissions from losses

- **Is a system model available?**
  - Is a detailed power systems analysis model (low-flow and production simulation models, such as mid-term and long-term generation dispatch simulations) available?

"Yes" Case:

- B8: If there is a system model available, input BE1 and go to "Module BE1" sheet:
  Use **Option A** if the model reports power generation only by plant, and not by fuel consumption.
  - B17–B39: Input years for the project.
    - Can be found in project preparation documents.
  - C17–C39: Input the expected electricity generation for the plant (MWh) for each corresponding year in column B.
    - Can be found in the power system model.
  - Columns D–L, rows 17–39: Each column represents an additional plant.
  - Repeat the same inputs for however many plants are being considered in the baseline.
  - C12: Input CO_2 emission factor of fuel type used in plant for column C in tCO_2 per gigajoule (GJ).
    - Can be found in IPCC Guidelines.[12]
  - C13: Input conversion efficiency (percent) of the grid-connected power plant feeding the project.
    - Can be found in one of the following sources in order of preference:
      - Source 1: Utility data on actual efficiency of existing plants.
      - Source 2: Relevant national or regional studies on power plant efficiency.
      - Source 3: Default efficiency from UNFCCC 2009.[13]

  Use **Option B** if fuel consumption for each power plant is provided by the power system model.
  - C58–L80: Input the expected fuel consumption for the plant for each corresponding year in column B.
  - Columns D–L, rows 17–39: Each column represents an additional plant.

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[12] IPCC (Intergovernmental Panel on Climate Change). 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories.* Geneva. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

[13] UNFCCC (United Nations Framework Convention on Climate Change). 2009. "Proposed New Baseline and Monitoring Methodologies." CDM-NM, Version 03.1. Bonn.

- Repeat the same steps, as noted above for Column C, for however many plants are being considered in the baseline.

- Return to "T&D Emissions Calculator" sheet.
- C8: Input PE1 and go to "Module PE1" sheet:
  - Repeat same procedure as in Module BE1, this time inputting project data from the system model.

"No" Case:

- B8: If there is no system model available, input BE2 and go to "Module BE2" sheet:
  - D9: Input the combined margin emission factor for the interconnected grid.
    - Can be calculated using UNFCCC (2009)[13] with ex ante options for operating and build margins.
    - Operating margin should be calculated as the simple operating margin if low-cost or must-run resources are less than 50 percent of total power generation, or as the weighted average operating margin if low-cost or must-run resources are more than 50 percent of total generation.
    - New plants that are committed to new capacity should be included in the margin calculations.
  - B13–B35: Input the years for the project.
    - Can be found in project preparation documents.
  - C13–C35: Input the estimated technical losses *without* the project for each corresponding year in column B.
    - The estimate should come from any technical study that determined the feasibility of the project and made ex ante estimations of the losses.
    - This could be a statistical analysis or other forms of nonsystem-based models.
- Return to "T&D Emissions Calculator" sheet.
- C8: Input PE2 and go to "Module PE2" sheet:
  - Repeat same procedure as in Module BE2, this time inputting project data.

Step 2. Calculate land-clearing emissions.

- Go to "Land Clearing" sheet.
- This module is based on AM45[14] and similar methodologies:
  - B9–18: Input the total hectares (ha) of land deforested in each subproject.
    - Can be found in project feasibility documents, or by computing the product of default right-of-way and line length.
  - C9–18 and D9–18: Choose corresponding climate and land type for land being cleared in each subproject.
    - Corresponding biomass densities are based on IPCC Guidelines.[12]

Step 3. Calculate SF_6 emissions.

- Go to the "SF_6" sheet.

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[14] AM0045: Grid connection of isolated electricity systems --- Version 2.0. Leakage emission module which is similar in many CDM methodologies.
http://cdm.unfccc.int/methodologies/DB/0XHXSW8OSSITEWX2YMKTBIL4R05OX5/view.html

- Four options are available for calculating SF_6 emissions, depending on the amount of data available for the project.
- Option A is the most data-intensive option, and option D is the least data-intensive. Option D uses a default factor based on a portion of national emissions.
- The decision tree in Figure 2A.2 should be used for choosing which option to select for calculating SF_6 emissions, depending on the amount of data available for the project.

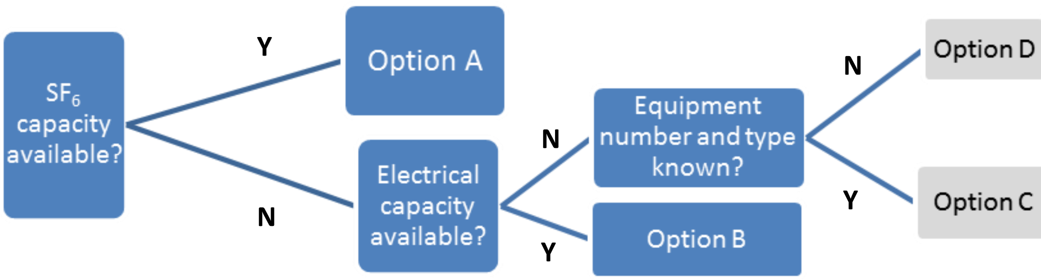


Figure 2A.2: Decision tree for SF_6 emissions estimation

- Use **Option A** if the project documents provide an inventory of the SF_6-containing equipment that will be installed as part of the project and the nameplate SF_6 capacity of each item of equipment. Standard emission factors can be applied to the SF_6 inventory.
  - Project preparation documents would have to provide data on the nameplate capacity in kilograms (kg) or metric tons (t) of SF_6 for all SF_6-containing equipment and separate this inventory into the relevant categories:
    - Sealed pressure
    - Closed pressure
    - Gas-insulated transformer, the related emissions of which will be computed on a case-by-case basis.
  - Since the emission factors are used on an annual basis, the economic life of the equipment would also be required to calculate lifetime emissions.
    - D12: Input nameplate capacity (t SF_6) of all sealed-pressure, SF_6-containing equipment used in the project.
      - Can be found in project preparation documents.
    - D13: Input nameplate capacity (tSF_6) of all closed-pressure SF_6-containing equipment used in the project.
      - Can be found in project preparation documents.
    - D16: Input SF_6 disposal emission factor (% SF_6) for sealed-pressure electrical equipment.
      - Can be found in the project or manufacturer guidelines for how SF_6 will be disposed of at the end of the project life.
    - D17: Input SF_6 disposal emission factor (% SF_6) for closed-pressure electrical equipment.
      - Can be found in the project or manufacturer guidelines for how SF_6 will be disposed of at the end of the project life.
    - D19: Input average economic life (years) of all SF_6-containing equipment.
      - Can be found in the manufacturer nameplate ratings of equipment life.

- Use **Option B** if project preparation documents provide a detailed list of all SF_6-containing equipment according to its rated power capacity—for example, kilovolt (kV) rating—but no actual data on how much SF_6 is in this equipment. The power capacity may be converted to SF_6 capacity using a scaling factor.

- D36: Input nameplate electrical capacity (tSF_6) of sealed-pressure SF_6-containing equipment used in the project.
  - Can be found in project preparation documents.
- D37: Input nameplate electrical capacity (tSF_6) of closed-pressure SF_6 containing equipment used in the project.
  - Can be found in project preparation documents.
- D41: Input average economic life (years) of all SF_6-containing equipment.
  - Can be found in the manufacturer nameplate ratings of equipment life.

▪ Use **Option C** if only the number of pieces of SF_6-containing equipment is known, regardless of whether it is known if they are closed pressure or sealed pressure. Option C uses an average SF_6 capacity based on the factors in Table 2A.1.

- D53: Input the number of pieces of sealed-pressure SF_6-containing equipment.
  - Can be found in project preparation documents.
- D54: Input the number of pieces of closed-pressure SF_6-containing equipment.
  - Can be found in project preparation documents.
- D60: Input average economic life (years) of all SF_6-containing equipment.
  - Can be found in the manufacturer nameplate ratings of equipment life.

Table 2A.1: Average SF_6 factors

Type of equipment	**Power rating**	**SF_6 capacity (kg)**	**Scaling factor (kg SF_6/kV capacity)**	**Default value if power rating not known (kg SF_6)**
Sealed-pressure SF_6 equipment	1–52kV	0.25–10	0.2	5
Closed-pressure SF_6 equipment	>52kV	3–200	0.5	100

Source: S. Wartmann and J. Harnisch. 2005. "Reductions of SF_6 Emissions from High and Medium Voltage Electrical Equipment in Europe," Project No. dm70047.2, Ecofys GmbH, Nurnberg, Germany.

▪ Use **Option D** if a detailed inventory of equipment using SF_6 is not available during project preparation.

- The average SF_6 use over the entire power sector in that country is used as the basis for determining a default emission factor per unit of electricity—for example, kg SF_6 per kilowatt-hour (kWh)—for high-, medium-, and low-voltage T&D systems.
- This is then allocated, with 75 percent to high-voltage (> 100 kV) and 25 percent to medium-voltage (38–100 kV) equipment.
- If the project is entirely **below 38 kV**, no SF_6 emissions are estimated.
- For projects where at least one line is **above 38 kV**, enter the following:
  - D74: Input average SF_6 emission factor (g SF_6/MWh) for the power sector in the project country, which can be found in the International Energy Agency's reported electricity consumption by country.[15]
  - D75: Input the global warming potential of SF_6, which is 23,900 tCO_2e/tSF_6.[16]

[15] "Electricity/Heat," IEA Energy Statistics, updated 2011. http://www.iea.org/stats/prodresult.asp?PRODUCT=Electricity/Heat.

[16] IPCC (Intergovernmental Panel on Climate Change). 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories.* Geneva. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

- B79–B98: Input the years for the project.
  - Can be found in project preparation documents.
- If the project involves **high-voltage lines (> 100 kV)**, use column C.
- If the project involves **medium-voltage lines (38–100 kV)**, use column D.
  - C79–C98: For each corresponding year in column B, input the yearly electricity transmitted (MWh/year) by the project activity over new high-voltage lines, measured at the exporting substation.
  - D79–D98: For each corresponding year in column B, input the yearly electricity transmitted (MWh/year) by the project activity over new medium-voltage lines, measured at the exporting substation.

Step 4. Calculate embodied emissions in construction materials (optional).

- Go to "Materials" sheet.
- This module is used only where the project preparation documentation includes data on quantities of materials used.
- The origin of the materials should also be known to identify the correct emission factors.
- Embodied emissions are the product of the mass of materials used and the relevant embodied emission factors, summed across all significant materials:
  - B11–B22: Input the type of material being used in the construction of the project (for example, steel).
  - C11–C22: Input the corresponding tons used for the project of the material in column B.
    - Can be found in engineering studies in project documentation or feasibility studies.
    - Input corresponding emission factor of the material in column B (tCO_2e/t). Can be found in the table from the IFC CEET,[17] or other similar databases (e.g. *Inventory of Carbon & Energy Version 1.5* at www.bath.ac.uk/mech-eng/sert/embodied/, or *Global Emission Model for Integrated Systems*, Oko Institute for Applied Ecology, www.gemis.de/en/index.htm).
    - Embodied emission factors should reflect the energy mix of the country of origin. For example, the sources of construction materials from a country dominated by hydropower should not use emission factors from Europe.
  - Repeat the same steps for baseline inputs M11–M22, N11–N22, and O11–O22.

Step 5. Calculate emissions from energy use in construction (optional).

- Go to "Construction" sheet.
- This module is used only where the project preparation documentation estimates fuel consumption by vehicles used during construction.
- Emissions are based on the fuel consumption in construction vehicles, the net calorific value of the fuel, and the emission factor of the fuel:
  - B12–B16: Input fuel type used in construction.
  - C12–C16: Input liters of corresponding fuel type consumed during construction in column B.

[17] IFC (International Finance Corporation). 2009. *IFC Carbon Emissions Estimator Tool (CEET).* Washington, DC: World Bank Group. <www.ifc.org/ifcext/climatechange.nsf/.../ifcceet/$FILE/IFC_CEET.xlsx>

Annex 2B: Examples

Important Note: These examples are for illustrative purposes only. They are not intended to reflect the actual emissions as calculated by teams, since these projects were appraised before the corporate requirement. Assumptions will be made for the illustrative purposes of showing the application of the guidance note and to complement information that may not have been available in project appraisal documents (PADs), but that may have been available to teams in additional project documents such as feasibility studies. Assumptions made are for the purposes of illustrating the application of the guidance note and may be different from the prevailing conditions and information available at the time of appraisal.

The examples also show the use of the Excel workbook described in Annex 2A. The use of this Excel workbook is not mandatory; teams can perform their own calculations using model/ tools used by the team or their consultants in project appraisal as long as the guidance is followed.

Example 2B.1: Eletrobras Distribution Rehabilitation Project, Brazil

The project aims to strengthen the management, operations, and corporate governance of the six distribution companies managed by Eletrobras (Amazonas Energia, Eletroacre, Ceron, Boa Vista, Cepisa, and Ceal). The project as described in the PAD contains two components: component 1, "Service Quality Improvement and Loss Reduction Program," and component 2, "Institutional Strengthening." Because only component 1 will support investment in infrastructure, the GHG calculations are carried out only for this component.

Component 1 consists of strengthening and rehabilitating the distribution networks and metering and information management systems. The component includes strengthening and rehabilitating substations, which would entail the acquisition and installation of cables, transformers, switches, breakers, posts, automatic meters in feeders, protection systems, ancillary equipment, and so on. Other equipment to be acquired and installed includes metering, distribution equipment for the supervisory control, voltage control, and switching needed to improve the reliability and quality of the electricity supply. This component represents the bulk of the project investment and helps reduce service interruptions, reduce technical losses, and improve the ability of the distribution companies to manage the grid effectively (including reducing nontechnical and billing losses). The relevant data in this example were taken from the analyses and data reported in the PAD.

Project and Baseline Selection

The objective of the component is to specifically pursue loss reduction first and also improve network reliability. The utilities require external support to finance investment that will lead to such reductions in losses and improvement of reliability. The alternative to the project is the continuation of the status quo, which will require producing more generation (to cover the losses) in order to fulfill the final consumer's energy needs. This is the baseline; it does not include other alternative configurations of T&D investments. Since the project will only upgrade or replace existing equipment, no land-clearing is involved in the project, and the main difference with the baseline will be emissions associated with avoided generation corresponding to the amount previously lost in T&D.

Step 1. Calculate avoided generation emissions associated with reduced losses.

Since there is no system model available for technical loss reduction, baseline emissions should be calculated using Module BE2 and project emissions using Module PE2 in the Excel workbook developed for this guidance note.

Module BE2: Emissions from Existing Technical Loss Rate

The investment analysis spreadsheets provide data on transmission losses both before and after project implementation for each of the six distribution companies. The emission factor for the Brazilian grid is 0.1045 tCO_2e/MWh provided in thePAD.

The PAD does not estimate loss reduction on an annual basis, but provides figures for a 10-year period (5,464 GWh over 10 years). This information is used in Module B to convert GWh to tCO_2. The estimated emissions are already relative to the baseline, because the energy savings were determined in relative terms.

The inputs and results for this module are given in Table 2B.1.

Table 2B.1: Computing emissions from losses

6					
7					
8		**Units**	**Value**		
9	**EF**	tCO2/MWh	0.1045		
10					
11	**Year**	**$TL_{BL,y}$**	**BEy**		
12		MWh	tCO2		
13	2012	546,400	57,099	Add as many lines as necessary for	
14	2013	546,400	57,099	number of years	
15	2014	546,400	57,099		
16	2015	546,400	57,099		
17	2016	546,400	57,099		
18	2017	546,400	57,099		
19	2018	546,400	57,099		
20	2019	546,400	57,099		
21	2020	546,400	57,099		
22	2021	546,400	57,099		
23			0		
24			0		
25			0		
26			0		
27			0		
28			0		
29			0		
30			0		
31			0		
32			0		
33			0		
34			0		
35			0		
36					
37	BE2		570,988		
38					

Module PE2: Emissions from Expected Project Loss Rates

Technical losses in the project scenario are set to zero because all loss reductions are captured in the baseline as described above.

Step 2. Calculate land-clearing emissions.

This step is not applicable, since none of the equipment to be installed will require additional right-of-ways. The project will rehabilitate or strengthen the existing distribution infrastructure only and therefore will not result in any land clearing.

Step 3. Calculate SF_6 emissions.

Because this project involves only technical loss reduction and increased reliability, step 3 also does not apply because of the low-voltage level of the system. The project team confirmed with the distribution companies that SF_6 equipment is not installed in low-voltage distribution lines or by this project.

Step 4. Calculate embodied emissions in construction materials (optional).

Since no data were available on the consumption of materials by the T&D project and on the origin of those materials, step 4 is skipped. It is not mandatory to perform this step if information is not available, given its expected relatively low magnitude.

Step 5. Calculate emissions from energy use in construction (optional).

Since no data were available on energy consumption during the construction phase of the T&D project and they are expected to be small, step 5 is skipped, as noted in the guidance note.

Step 6. Summarize T&D emissions.

The GHG emissions resulting from T&D should be summarized in the T&D Emissions Calculator Module in Table 2B.2.

Table 2B.2: Summary of emissions

	A	B	C	D	E	F	G
1		**Baseline**	**Project**	**Net**			
2	Land clearing	0	0	0			
3	SF6	0	0	0			
4	Embodied emissions	0	0	0			
5	Energy in construction	0	0	0			
6	Generation emissions from losses in the project	570,988	0	-570,988			
7		BE2	PE2	BE1 or BE2; PE1 or PE2			
8	**Total Emissions**	570,988	0	**-570,988**			
9							
10	Key		Inputs				
11			Calculations				
12			Outputs				
13							
14							

Example 2B.2: Energy Access Scale-up Program, Kenya—Eldoret-Kitale Line Project

There are two related T&D components in the operation. The first component consists of the construction of 132 kV transmission lines: (a) Kindaruma-Mwingi-Garissa; (b) Eldoret-Kitale; and (c) Kisii-Awendo. These lines are among the eight 132 kV transmission lines that the government has designated as priorities for construction during the period 2010–15. This component will construct 60 km of 132 kV single-circuit transmission lines, including the establishment of a 132/33 kV, 23 megavolt ampere (MVA) substation at Kitale. The 33 kV network that will be influenced by this project is the 33 kV radial from the Eldoret 132/33 kV substation supplying the 33/11 kV substations Moi Barracks, Moi's Bridge, Cheranguria, Kitale, and Kapenguria. Several 33/0.4 kV distribution transformers are also connected to this 33 kV radial, mostly concentrated between Moi Barracks and Moi's Bridge.

The second component will have four subcomponents that will support the expansion and upgrading of the distribution network, along with the connection of an additional 300,000 customers over the period 2011–16. About 17 percent of household connections will be in urban slums. In the areas of the project where the distribution investments will take place, an increasing number of new customers will come from lower-income urban areas and rural areas. This example takes one of the components, the objective of which is to reduce technical losses in the distribution network.

Step 1. Calculate avoided generation emissions associated with reduced losses.

Since there was no system model available for technical loss reduction, baseline emissions are calculated using Module BE2 and project emissions using Module PE2.

Transmission Component

Baseline determination. Alternatives to the transmission project are not identified in the PAD.[18] Following the guidance note, it is assumed that the baseline is the high-efficiency benchmark, the land-clearing and SF_6 emissions of which are zero and that has very low technical losses of 2 percent.

Project Emissions

The economic analysis annex of the PAD shows the annual additional generation transmitted and delivered to end users as a result of loss reduction in the form of economic benefits. These benefits are expressed in millions of U.S. dollars representing the equivalent incremental generation additions each year, valued at the long rung marginal cost of generation plus incremental transmission cost (as a reflection of willingness to pay). The PAD also indicates that transmission losses are 4 percent in the transmission system. These figures are used to estimate the total amount of additional energy that will be transmitted over all the lines (subprojects) where losses are reduced.

The combined margin emission factor for the interconnected grid is 0.6545 tCO_2/MWh.[19]

The inputs and results for the project emissions are shown in Table 2B.3.

[18] Alternatives may be available in consulting work files. This example applies the methodology only on the basis of information available in the PAD for illustrative purposes.
[19] UNFCCC (United Nations Framework Convention on Climate Change). 2009. "Proposed New Baseline and Monitoring Methodologies." CDM-NM, Version 03.1. Bonn.

Table 2B.3: Computing emission from losses

		Units	Value		
	EF	tCO2/MWh	0.6545		
	Tariff	$/kWh	0.2164		
	Losses	%	4%		

Year	Incremental Benefit	Incremental Generation	Incremental Losses	PEy	
	$US millions	MWh	MWh	tCO2	
2011	0	0	0	0	Add as many lines as necessary for
2012	0	0	0	0	number of years
2013	0	0	0	0	
2014	13.9	66,909	2,676	1,752	
2015	16.1	77,499	3,100	2,029	
2016	18.5	89,052	3,562	2,331	
2017	21.2	102,049	4,082	2,672	
2018	24	115,527	4,621	3,024	
2019	27.1	130,449	5,218	3,415	
2020	30	144,409	5,776	3,781	
2021	33.4	160,775	6,431	4,209	
2022	37	178,104	7,124	4,663	
2023	40.9	196,877	7,875	5,154	
2024	45	216,613	8,665	5,671	
2025	49.5	238,274	9,531	6,238	
2026	54.2	260,898	10,436	6,830	
2027	59.3	285,447	11,418	7,473	
2028	64.8	311,922	12,477	8,166	
2029	70.7	340,323	13,613	8,910	
2030	76.9	370,167	14,807	9,691	
2031	83.6	402,418	16,097	10,535	
2032	91.1	438,520	17,541	11,480	
2033	98.6	474,623	18,985	12,426	
2034	99.3	477,992	19,120	12,514	
2035	99.3	477,992	19,120	12,514	
2036	99.3	477,992	19,120	12,514	
2037	99.3	477,992	19,120	12,514	
2038	99.3	477,992	19,120	12,514	
2039	99.3	477,992	19,120	12,514	
2040	99.3	477,992	19,120	12,514	
2041	99.3	477,992	19,120	12,514	
2042	99.3	477,992	19,120	12,514	
2043	99.3	477,992	19,120	12,514	
2044	99.3	477,992	19,120	12,514	
2045	99.3	477,992	19,120	12,514	
2046	99.3	477,992	19,120	12,514	
2047	99.3	477,992	19,120	12,514	
2048	99.3	477,992	19,120	12,514	
2049	99.3	477,992	19,120	12,514	
2050	99.3	477,992	19,120	12,514	
PE2				333,186	

Baseline Emissions

The benchmark baseline efficiency for transmission projects is a 2 percent loss. Since the baseline delivers the same level of service, the same inputs for incremental generation are used in Table 2B.4.

Table 2B.4: Computing emission from efficient T&D baseline benchmark

		Units	Value		
	EF	tCO2/MWh	0.6545		
	Tariff	$/kWh	0.2164		
	Losses	%	2%		
Year	Incremental Benefit	Incremental Generation	TL	BEy	
	$US millions	MWh	%	tCO2	
2011	0	0	-	0	Add as many lines as necessary for
2012	0	0	-	0	number of years
2013	0	0	-	0	
2014	13.9	66,909	1,338	876	
2015	16.1	77,499	1,550	1,014	
2016	18.5	89,052	1,781	1,166	
2017	21.2	102,049	2,041	1,336	
2018	24	115,527	2,311	1,512	
2019	27.1	130,449	2,609	1,708	
2020	30	144,409	2,888	1,890	
2021	33.4	160,775	3,215	2,105	
2022	37	178,104	3,562	2,331	
2023	40.9	196,877	3,938	2,577	
2024	45	216,613	4,332	2,835	
2025	49.5	238,274	4,765	3,119	
2026	54.2	260,898	5,218	3,415	
2027	59.3	285,447	5,709	3,737	
2028	64.8	311,922	6,238	4,083	
2029	70.7	340,323	6,806	4,455	
2030	76.9	370,167	7,403	4,845	
2031	83.6	402,418	8,048	5,268	
2032	91.1	438,520	8,770	5,740	
2033	98.6	474,623	9,492	6,213	
2034	99.3	477,992	9,560	6,257	
2035	99.3	477,992	9,560	6,257	
2036	99.3	477,992	9,560	6,257	
2037	99.3	477,992	9,560	6,257	
2038	99.3	477,992	9,560	6,257	
2039	99.3	477,992	9,560	6,257	
2040	99.3	477,992	9,560	6,257	
2041	99.3	477,992	9,560	6,257	
2042	99.3	477,992	9,560	6,257	
2043	99.3	477,992	9,560	6,257	
2044	99.3	477,992	9,560	6,257	
2045	99.3	477,992	9,560	6,257	
2046	99.3	477,992	9,560	6,257	
2047	99.3	477,992	9,560	6,257	
2048	99.3	477,992	9,560	6,257	
2049	99.3	477,992	9,560	6,257	
2050	99.3	477,992	9,560	6,257	
BE2				166,593	

Distribution Component on Technical Loss Reduction

The PAD does not provide figures on technical losses for each year, but rather on net annual technical loss reductions expressed in monetary terms (millions of U.S. dollars) that value losses at the average tariff of US$0.11 per kilowatt-hour (kWh). With these parameters the losses in MWh are computed. These losses (which are already expressed as net loss reduction relative to the "without-project" case) are entered in the Excel model as baseline losses and project losses are set equal to zero (direct net calculation).

The combined margin emission factor for the interconnected grid is 0.6545 tCO_2/MWh.[19]

The inputs and results for this module are summarized in Table 2B.5.

Table 2B.5: Computing emissions from distribution losses

6					
7					
8			Units	Value	
9		EF	tCO2/MWh	0.6545	
10		Tariff	$/kWh	0.11	
11					
12					
13	Year	Incremental Benefit	$TL_{PJ,y}$	PEy	
14		$US millions	MWh	tCO2	
15	2011	0	0	0	Add as many lines as necessary for
16	2012	0	0	0	number of years
17	2013	4.61	41,909	27,430	
18	2014	5.18	47,091	30,821	
19	2015	5.82	52,909	34,629	
20	2016	6.53	59,364	38,854	
21	2017	7.34	66,727	43,673	
22	2018	8.25	75,000	49,088	
23	2019	9.27	84,273	55,157	
24	2020	10.42	94,727	61,999	
25	2021	11.7	106,364	69,615	
26	2022	13.15	119,545	78,243	
27	2023	14.77	134,273	87,882	
28	2024	16.6	150,909	98,770	
29	2025	18.65	169,545	110,968	
30	2026	20.96	190,545	124,712	
31					
32	BE2			911,838	

Step 2. Calculate land-clearing emissions.

The benchmark baseline assumes zero land-clearing emissions. The project emissions are calculated based on the length of the new transmission lines and the biomass density of the region.

The PAD makes no mention of the right of way for the new 132 kV line, so the default figure of 30 m, based on discussions and feedback from World Bank staff, is applied. Combined with the distance of 60 km, this gives an area of 180 ha.

With respect to the potential emissions from land clearing, an assumption has been made, based on the limited information available in the PAD, that the land can be described as “Cropland—Tropical (moist region), perennial woody biomass.” Therefore, the input for climate should be “tropical,” and the input for type of land should be “moist cropland.”

The inputs and results for this module are summarized in Table 2B.6

Table 2B.6: Computing land clearing emissions

$PE_{LC} = A_{,def} \times BD$

	Area (ha)	Climate	Type of Land	BD (tCO2e/ha)	PE_{LC}
Subproject 1	180	Tropical	Moist Cropland	77	13860
Subproject 2		Tropical	Rain Forest	440	0
Subproject 3		Tropical	Rain Forest	440	0
Subproject 4		Tropical	Rain Forest	440	0
Subproject 5		Tropical	Rain Forest	440	0
Subproject 6		Tropical	Rain Forest	440	0
Subproject 7		Tropical	Rain Forest	440	0
Subproject 8		Tropical	Rain Forest	440	0
Subproject 9		Tropical	Rain Forest	440	0
Subproject 10		Tropical	Rain Forest	440	0
Total		Tropical	Rain Forest	440	13,860
Key		Inputs			
		Calculations			
		Outputs			

Baseline

	Area (ha)	Type of Climate	Type of Land	BD (tCO2e/ha)	PE_{LC}
Subproject 1	0	Tropical	Wet Cropland	183	0
Subproject 2		Tropical	Rain Forest	440	0
Subproject 3		Tropical	Moist Cropland	77	0
Subproject 4		Tropical	Rain Forest	440	0
Subproject 5		Tropical	Rain Forest	440	0
Subproject 6		Tropical	Rain Forest	440	0
Subproject 7		Tropical	Dry Forest	191	0
Subproject 8		Tropical	Rain Forest	440	0
Subproject 9		Tropical	Rain Forest	440	0
Subproject 10		Tropical	Rain Forest	440	0
Total		Tropical	Rain Forest	440	0
Key			Inputs		
			Calculations		
			Outputs		

Step 3. Calculate SF_6 emissions.

The benchmark baseline assumes zero SF_6 fugitive emissions. The project emissions are calculated based on the SF_6 decision tree based on the level of information available.

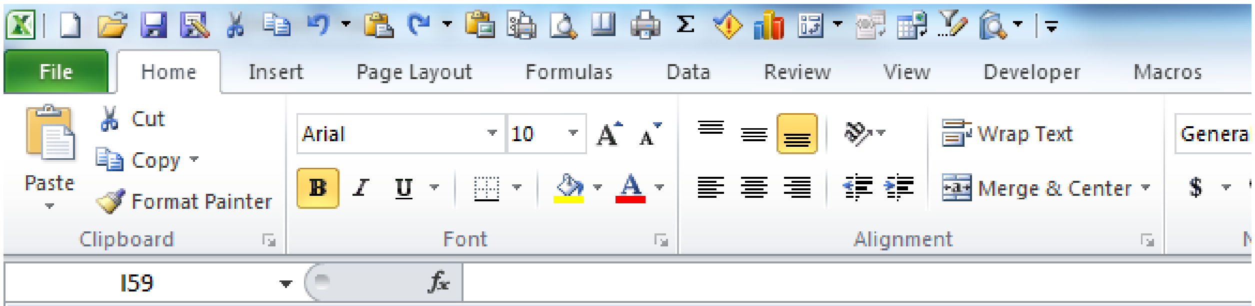
This case study provided an indication of the number of pieces of SF_6-containing equipment that would be installed during project implementation and their respective capacities. Therefore, it was possible to use option C in the Excel model to estimate GHG emissions from SF_6-containing equipment.

The PAD states that seven SF_6-containing, sealed-pressure units and six SF_6-containing, closed-pressure units would be installed.

For disposal emissions, it is assumed that all of the SF_6 will be recovered, because World Bank projects must follow strict environmental guidelines. The project life is 20 years.

The inputs and results for this module are summarized in Table 2B.7.

Table 2B.7: Computing SF_6 emissions



Option C: Only number and type of equipment is known, not capacity

$$PE_{SF6,y} = \left[\left(N_{SP} \times ACap_{SP} \times EF_{SF6,Use,SP}\right) + \left(N_{CP} \times ACap_{CP} \times EF_{SF6,Use,CP}\right)\right] \times GWP_{SF6}$$

$$PE_{SF6,tot} = \sum_{y=1}^{EL} PE_{SF6,y}$$

	Units	Value
N_{SP}	no units	7
N_{CP}	no units	6
$ACap_{SP}$	t SF6	0.005
$ACap_{CP}$	t SF6	0.1
$EF_{SF6,Use,SP}$	%	0.2%
$EF_{SF6,Use,CP}$	%	2.6%
GWP_{SF6}	tCO2-e/t SF6	23900
EL	years	20
$PE_{SF6,y}$	tCO2-e	375
$PE_{SF6,tot}$	tCO2-e	7490

Steps 4 and 5. Calculate embodied emissions and emissions from energy use during construction.

Since no data were available on materials consumption by the T&D project and on the origin of those materials, step 4 is skipped.

Since no data are available on energy consumption during the construction phase of the T&D project, step 5 is skipped.

Summarize T&D emissions.

The GHG emissions resulting from T&D are summarized in the T&D Emissions Calculator Module as shows in Table 2B.8.

Table 2B.8: Summary of emissions

	A	B	C	D	E
1		**Baseline**	**Project**	**Net**	
2	Land clearing	0	13,860	13,860	
3	SF6	0	7,490	7,490	
4	Embodied emissions	0	0	0	
5	Energy in construction	0	0	0	
6	Generation emissions from losses in the project				
7	Transmission Component	166,593	333,186	166,593	
8	Distribution Component	911,838	0	-911,838	
9		BE2	PE2	BE1 or BE2; PE1 or PE2	
10	**Total Emissions**	**1,078,431**	**354,536**	**-723,895**	
11					
12	Key		Inputs		
13			Calculations		
14			Outputs		
15					

3. Generation Projects

This chapter presents guidance for computing GHG emission of power generation projects. Because of several unique requirements for hydropower, hydropower projects are treated separately in the next chapter. In addition to reviewing this chapter, it is recommended that the main concepts and principles found in the first chapter be reviewed as well.

3.1 Typology of Generation Projects

Typical World Bank interventions for electricity generation can be broadly classified into three categories:

(a) New (greenfield) projects to increase power supply using a range of technologies and fuel sources, other than hydropower.
(b) Hydropower generation projects—new, expansions, rehabilitations and/or life extensions.
(c) Rehabilitation and/or life extension of thermal generation projects.

This chapter describes the process that should be used for GHG accounting of the World Bank's interventions in the first category of projects. The second category is dealt with in the next chapter. Guidance for thermal rehabilitation is under development and is not covered in this version of the guidance note. The majority of World Bank support is for the first two categories. Technology types in the first category, which is the subject of this chapter, include all thermal and renewable sources, except biomass cogeneration for which guidance is still under development. For any generation-related project that seeks any form of climate finance support (such as GEF or CDM), the project should use the corresponding internationally agreed methodologies and report emissions so calculated for the World Bank's corporate requirement. GHG accounting is not yet required to be performed for project interventions for which there is currently no agreed methodology. This guidance note will be updated when new methodologies are developed.

3.2 Project Boundaries and Sources of Emissions

The boundaries for calculating emissions associated with power generation are limited to the physical boundary of the generation itself being supported by the World Bank.

The most important emissions in power generation are these that result from fossil fuel combustion in the power plant and other emission related to maintenance activities such as replacement of worn parts and lubricating oils, or maintenance of temperature in solar trough systems. These emissions correspond to Scope 1 and are included in the GHG accounting for power generation project.

With regard to Scope 2 emissions, emissions associated with steam used in the power plant, if not produced directly in the power plant, should be included.

"One-off" emissions such as those associated with construction and decommissioning are considered low or negligible relative to overall operational emissions. In addition, in some cases, these emissions cannot feasibly be computed during project appraisal. For instance, emissions associated with material manufacturing depend on the place of manufacturing, which is not known during project appraisal and becomes known only during project execution.

Emissions associated with fuel provisioning for constructing power plants fall under Scope 3 in this guidance. Guidance on when Scope 3 may be considered significant will be issued at a later stage. In general, emissions from combustion are the most important for power generation projects and are the most relevant from a portfolio foot-printing perspective. As such, these are the only emission that will be considered for power generation projects covered in this chapter.

3.3 Sources of Emissions

Required:

Operational Emissions

Operational emissions refer mainly to combustion, which depend on the type of fuel and technology being used. Other emissions from energy used during operations such as auxiliary energy used in renewable technologies are also considered operational emissions.

Optional:

Upstream Emissions

These include raw material production, component manufacturing (including electricity used during manufacturing), transportation from the manufacturing facility to the construction site, and on-site construction. These emissions tend to be small compared to lifetime emissions for thermal generation projects, but are larger for renewable generation projects. Fuel provision is also in this category (part of Scope 3).

Downstream Emissions

These refer to disposal emissions. Disposal emissions result from decommissioning a generation facility and include emissions associated with energy used during the process. Since these emissions are expected to be relatively small, estimated default factors will be used. Disposal typically captures the emissions associated with dismantling and transportation up to the point of recycling the components, but does not include the recycling itself.

Emissions from rebound effects (or leakage) resulting from changes in energy prices and electricity demand—which could result from changes in fuel types in response to variations in global fuel prices or technology costs—are also downstream impacts that are not mandatory for this accounting requirement.

3.4 Computing Gross and Net Emissions

Net emissions are calculated as the difference between project and baseline emissions. Table 3.1 provides an example.

Table 3.1: Sample calculation of generation emissions

	Baseline	Project	Net
Upstream (one-off) emissions	0	0	0
Generation emissions (combustion)	30	80	50
Downstream (one-off) emissions	0	0	0
Total Emissions	30	80	**50**

Note: All quantities are in $tC0_2e$. The numbers are for illustrative purposes only. This could be a thermal generation project with a less GHG-intensive alternative.

3.5 Defining the Baseline

The baseline, or alternative, to the project in the case of greenfield generation is not “no project,” but rather the most likely project or mix of substitute projects or response that provides the same level of service, for example, the generation profile that leads to the same energy supply to the final consumer. While there could be many technical alternatives to provide the same level of service as the project, the most likely alternative is defined as the next more feasible alternative from the technical, economic, financial, and regulatory perspective, taking into consideration specific country conditions. In some cases the only truly feasible generation option may be the one for which the World Bank is providing financing (leading to net zero emissions). However, for the purposes of performing GHG emissions accounting, an alternative different from the project needs to be identified to make the assumptions in GHG emissions accounting conservative.[20]

To balance the level of effort with completeness and accuracy, the chart in Figure 3.1 provides guidance on the methods that can be used to determine the baseline following the above general principles. Table 3.2 presents the basic formulas for emissions calculation that correspond to each case in the flowchart. All the formulas require subtracting the baseline emissions from the project emissions to arrive at net emissions. The difference lies in how the emissions of the baseline are modeled, which can vary from approximating grid emissions for a small project, to a combined margin model, and to integrated power system modeling to assess and determine the most likely alternative for larger projects. As mentioned in section 1.4, not all project contexts can be anticipated, and therefore the

[20] For example, in a low-access, low-income country where avoiding further load-shedding in the short term is the objective of a generation project, diesel-based power generation may be the only technically, economically, and institutionally feasible option within the timeframe required. For the purpose of GHG emissions accounting, the baseline may be defined as an alternative means of power generation within a comparable (but not exactly the same) timeframe, such as wind or solar backed up by battery storage and diesel power generation (which will be on a smaller scale than the project itself), a similar diesel-based project with higher efficiency enabled by greater lead time, or any other option that may not be immediately feasible but that is the next most likely option.

assignment of generation plant types and sizes in different boxes in the figure should not be considered rigid. As experience is gained with GHG emissions accounting, the flowchart may be modified.

In general, the larger the project, the more detailed the assessment of alternatives is likely to be. For relatively small projects, teams should exercise their own judgment on whether a fuller analysis of alternative options should be conducted, similar to a larger project. Teams can select to follow a more detailed method—compared to the default options in the flow chart—to compute baseline emissions following general principles in this guidance note. One exception is greenfield coal-based power generation, for which the requirement for baseline identification is the same, irrespective of size, as that for additions larger than 150 MW in the flowchart.

Figure 3.1: Project size and baseline alternative flowchart

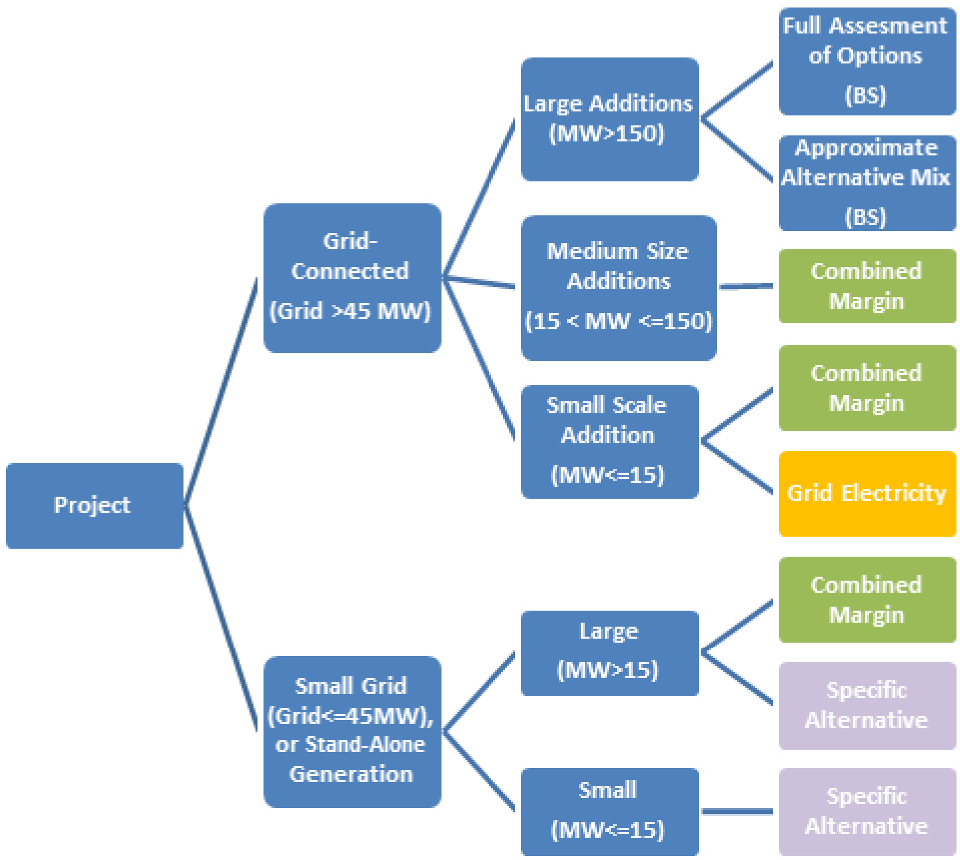


Table 3.2: Baseline model type and basic formulas

Baseline model type	Overall formula for net emissions (NE) and brief description
Specific Alternative	***NE = project emissions – alternative project emissions*** The most likely alternative to the project is a specific project that provides the same level of service.
Grid Electricity	***NE = project emissions – project generation × grid emission factor*** This applies mostly to marginal additions of electricity to the system, which will otherwise be met by additions through other generation options in the grid.
Combined Margin	***NE = project emissions – project generation × combined margin emissions*** ***Combined margin emissions = operating margin × grid emission factor + build margin × build margin emissions*** If a project is designed to contribute to supply adequacy of the system (for example, additions to firm energy or capacity requirements), the most likely alternative needs to be modeled by operating and build margins. The operating margin means the alternative in part will be similar to the existing grid mix and hence the grid emission factor can be used. The building margin represents alternative plants that could be added to the system to provide the same service (for example, firm energy or capacity) as the project.
Full assessment of options (BS) Approximate Alternative Mix (BS) BS = barrier screening (see Box 3.1 below)	***Net emissions = project emissions – alternative mix emissions*** The most accurate way to determine an alternative project or mix of projects that provide the same level of service (meets the same energy and capacity requirements) as the project is to use power system planning and dispatch models that are likely to be available as part of the technical and economic assessment of projects that are significant in size. In such cases, net emissions can be obtained directly from the power systems planning models by comparing a scenario in which the project is included in the planning framework with a scenario without the project while meeting the same service requirements (for example, reliability levels as defined by reserve margins or other probabilistic measures). If such models are not available, information from other studies can be used to arrive at approximate estimates of an alternative mix of projects that could be considered the most likely alternative to the project from all the feasibility angles, which requires proper analysis of all the barriers to potential alternatives.

Use of the Baseline Flow Chart

Table 3.3 provides further guidance on how each baseline type should be applied for different project sizes. Guidance on how to estimate the main parameters or select default values is also described, along with a reference to the tools made available to teams for calculating net project emissions using the different baselines.

Table 3.3: Detailed emissions calculation process for different project sizes

Project size	Baseline description
Small-scale addition (≤15MW) to the grid (grid > 45 MW)	**Baseline option 1: grid electricity.** This option represents generation addition, whether renewable or fossil fuel, that does not add considerably to the supply adequacy of the grid (that is, meet the energy demand within the desired reliability levels). In the absence of the project, these marginal additions most likely can be supplied by one or more of the sources to the grid. This baseline can also be used when the number of options may be limited, due to the relevance of the project to a particular system and the national conditions. The default is to use grid emissions, approximated by the latest grid average emission factor. [21] If using the tools provided with the guidance note, use the grid electricity option[22] to determine the gross baseline emissions. **Baseline option 2: combined margin.** In some cases, even if the addition is small, it may improve the supply adequacy of the grid (for example, adding capacity at peak demand such as a 15 MW firm addition to a 100 MW grid). In such cases, the most likely alternative can be considered to be partially similar to current grid electricity and partially to alternative sources that can similarly provide the same service (assessed in terms of supply adequacy, base load, peak generation, or other metrics). Use the Combined Margin formula in Table 3.2 with following fixed parameters: For thermal projects: Operating margin factor = 50% Build margin factor = 50% For all renewable energy projects: Operating margin factor =75% Build margin factor = 25% **Operating emissions.** The default operating emissions will be the average grid emissions that can easily be obtained from various sources. **Build margin technology** = most efficient power plant operating in the grid in a similar regime to the addition (peak, mid-base, or base-load). For instance, if the project is for peaking, the build margin technology may be the most efficient peaking diesel power plant if gas-fired turbines are not available to the system.
Medium-size addition (15 < MW ≤ 150) to the grid (grid > 45 MW)	**Baseline option: combined margin.** These additions represent projects of considerable size relative to the total existing grid capacity and contribute to the supply adequacy of the system (for example, meet energy demand growth and help meet critical conditions such as the dry season in a hydro-thermal system or peak demand with additional capacity in thermal systems). The most common situation would be a thermal or renewable project of

[21] Average grid emission factors can always be easily verified and obtained. For this reason, it is used as the default value. However, more detailed methods can be used to estimate operating emissions as long as methods consistent with globally accepted guidelines are used, such as the CDM guidance note and tools for computing grid emission factors (*Tool 07).*

[22] See annex 3A with a description of the tool that is supplied to help implement the process and 3B with illustrative examples. Note that performing accounting does not require the use of a specific tool; rather, teams can opt to use their own models as long as the principles in the guidance note are followed.

Project size	Baseline description
	any kind that generates power to meet some energy as well as capacity (or firm energy) needs depending on each project output characteristics and the needs of the system. In this case, the Combined Margin formula of Table 3.1 formula should be used. The main difference between medium-size and small projects is that for medium-size projects, additional information is generally available to estimate the contribution of the project to supply adequacy and, with that, more information should be available to determine which building margin technologies should be considered for the baseline. **Determining Build and Operating Margin Parameters** For thermal projects: Operating margin factor = 50% Build margin factor = 50% For all renewable energy projects: Operating margin factor =75% Build margin factor = 25% **Operating emissions.** The default operating emissions will be the average grid emissions that can easily be obtained from various sources. Whenever a more accurate method to estimate operating grid emissions is available, teams can choose to use such a method. By default, the grid emission factor remains constant for the life of the analysis, unless enough information to quantify the emissions path of the sector is available from a credible plan officially endorsed by the government is available, in which case dynamic emission factors changing over the years in the life of the project can be used. More detailed methods to estimate operating emissions can be used as long as methods that are consistent with globally accepted guidelines are used, such as the CDM guidance and tools for computing grid emission factors (Tool07).[23] **Determining Build Margin Emissions Parameters** The computation should use average emissions from the most recent additions to the grid of similar size to the project in MW and that will be used in a similar fashion. Ideally the five most recent projects should be used if enough history is available, but otherwise projects over the three years preceding the expected appraisal year. If there is no history, the most likely alternative to the project is one that comes from a full assessment of options and determination of the most likely alternative that is different from the project. If the project has the objective of meeting peak demand, the peaking technologies should be used. If the project has the objective of meeting base-load demand, similar technologies should be used. Peaking technologies used in each system depend on the fuel available. Fuel oil is always an alternative if gas (for running gas turbines) is not available. When the project consists of addition of renewable energy technologies, the output of which is not controllable, the building margin technologies considered should be simple: the five most recent projects, regardless of their utilization patterns on how they compare to the renewable addition, or if such history is not available, projects over the three years

[23] "Clean Development Mechanism Tool07, Methodological Tool: Tool to calculate the emission factor for an electricity system." http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v3.0.0.pdf.

Project size	Baseline description
	preceding the expected appraisal year. The fact that renewables are not controllable is already considered, from the GHG accounting point of view, by the fact that the building margin factor is set equal to only 25%. That is, renewable technologies are not expected to displace a considerable amount of new investments. In cases where the profile of the renewable energy has been studied in detail and their contribution to supply is better known from long- and short-term system simulations, or when such models have been used to asses alternatives or perform the economic appraisal of other forms of generation, teams can opt to use the baseline approach for large additions, which allows for considering the output of power system tools to determine the most likely alternative case that provides the same level of service.
Large addition (MW >150) to the grid (grid > 45 MW), and all greenfield coal projects irrespective of size	Large additions are likely to be designed to increase the supply adequacy of a grid considerably (for example, to meet energy demand growth and help meet critical conditions, such as the dry season in a hydrothermal system or peak demand with additional capacity in thermal systems). Such large projects are expected to be part of the long-term (usually least-cost) expansion strategy, and their contribution to supply adequacy is clearly understood from such studies. The alternative to the project is considered the most likely project, or alternative mix of projects, that provides the same level of service taking into account all feasibility angles (economic, financial, technical, legal, and regulatory). There are two modeling alternatives to determine the base-line emissions. Both follow the same underlying principle, and the choice between them would depend on the availability of data and models from the project appraisal process. **Baseline option 1: full assessment of options, with power system modeling approaches.** A power system planning study with the analysis of alternatives, carried out with various power system modeling approaches, will most likely be available during project appraisal. A full assessment of alternatives is already part of the Operational Guidelines requirements for any coal generation project irrespective of the size. All coal projects are expected to perform full assessment of options. The project or a mix of projects that is a likely alternative can be identified with such power system planning and dispatch models by simply restricting the project to the options in the model (that is, running a without-project scenario). The model will determine the mix of projects that provide the same level of service and meet the given reliability criteria (for example, reserve margin or loss of load probabilities). Most of these models also provide the operating emissions of the mix with and without the project. In such cases, the data directly reported by the power system models can be used to estimate emission with and without the project. Such models would provide the most accurate alternative mix possible that provides the same level of service as the project, taking into account the reliability implications of different generation technologies and how they interact in the system to supply the demand. **Baseline option 2: approximate alternative mix.** If a power system planning model is not available for further scenario building (for example, run the model with and without the project to identify alternatives), an approximate method can be used to determine the project or set of projects that can be considered a project alternative. The data from the feasibility studies—the expected contribution of the project to meeting load, capacity, and

Project size	Baseline description
	firm energy—can be used to determine an alternative mix that provides a similar load fulfilling profile. The mix of projects would be such that together they provide a similar pattern of output/service (such as the same base-load output) as the project. If the project is a peaking project, the mix has to provide a similar type of output.[24] That an alternative provides the same level of service is not sufficient to make it a realistic alternative. The alternative needs to be likely from a number of different angles. Assessing whether a project (or a plan) is truly a feasible option requires analyzing all the feasibility aspects of the project—economic, technical, financial, legal, and regulatory. The higher the number and complexity of barriers, the less likely the project will be the next most-likely alternative. For example, a project may require a huge capital cost that is not available at the time of project selection (for example, solar power without an explicit financing source to compensate for extra costs), it may not be feasible from the legal point of view (for example, lack of law or treaty to develop a cross-border project), or it may not be ready in the time required (for example, lack of gas infrastructure that may require more time to build than the timeline required for the project). **Box 1 offers a checklist** that could help guide the team's analysis to identify the barriers to different alternatives. The project with the least number and complexity of barriers will be considered the next most likely for the purposes of determining the baseline.
Addition to a small grid (grid ≤ 45MW), or stand-alone generation	There are two alternatives, depending on the project size as described in Figure 3.1. The baseline modeling and parameters are estimated as already explained in the above sections. **Baseline option 1 (small project ≤ 15MW or larger project): specific project.** The alternative to the project is another generation project which will provide the same level of service (such as energy and/or capacity). The baseline project will most likely use a different technology with different emissions.[25] **Baseline option 2 (larger project >15 MW): combined margin approach, with default parameters.** Refer to the procedure already described for medium-size projects.

Box 3.1. Barrier Screening (BS) Guidelines to Assess the Likeliness of Alternatives
The most likely project will usually be that with the least number and complexity of barriers. Project teams can use the following screening guidelines to assess the baseline alternatives. In some cases, there will be many barriers to alternatives, and the project may be the only option. Even in such cases, the baseline cannot be a "no-project" for the purposes of GHG accounting, but should be the one with the least number of barriers that are the least difficult to overcome based on the team's assessment of all the feasibility factors. The list below is not meant to be comprehensive or limiting, since the project objectives (the service it will provide) and country circumstances always need to be considered when assessing alternatives.

[24] Annex 3A describes the tool that can be used by teams to help computing emission from generation project. The tool includes mix-tool option to implement this baseline option. The mix tools allow approximating a combination of three different most likely technologies plus additional electricity from the grid that yields a similar level and profile of output as the project from the energy perspective in different load-ranges (mid, base, peak).

[25] For example, if the project is a small hydropower plant to supply a small remote distribution utility not connected to the national grid, the alternative could be a specific project such as a similar-size diesel power generator.

1) **Technical barriers.** While a baseline could be feasible from the energy and supply adequacy point of view, other technical limitations and barriers need to be considered, including the following:
    i) The alternative project(s) cannot be completed within the timeframe required by the project after a careful review of all possible technical solutions. For instance, an alternative could consist of a hydropower plan with a large reservoir that realistically cannot be developed in the timeframe required by the project.
    ii) Fuel supply issues that lead to fuel supply conditions that cannot guarantee reliability comparable to the project. This could be a gas pipeline alternative where the availability of gas is not guaranteed from the supplier. Another situation could be that of a diesel plant as an alternative to a small hydropower project in a remote area, where reliable diesel supply cannot be guaranteed.
    iii) Constraints on proper network operation to evacuate and distribute power from alternatives. This could be a situation, for example, where the next least-cost alternative to a large project consists of a number of renewable projects with varying sizes and different technologies, whose operationalization in the grid cannot be guaranteed within the timeframe of the project based on existing experience in the grid.
    iv) Others barriers that make the alternative infeasible include the lack of additional infrastructure for logistics, operation, or maintenance of the alternative or a much higher risk of technological failure than the project.
2) **Financing or investment barriers.** The alternative project may have a higher financial cost than the project that provides the same level of service. There may be barriers that make such an alternative infeasible, including the following:
    i) The alternative solution may consist of technologies, sizes, and/or additional technical needs (from the above list 1) that are considerably more expensive compared to the project. The absence of additional financing, grants, or specific support mechanisms to buy down the incremental cost makes financing infeasible.
    ii) Alternatives may have lower financial costs over the life of the project, but high capital costs that are difficult to finance.
    iii) Alternatives perceived as being risky may not be able to mobilize capital from the national or international markets to finance the project and to insure financial risks.
    iv) There may be others barriers assessed by teams as part of project appraisal.
3) **Economic barriers.** The alternative are uneconomic alone or if compared to others after considering all project costs such as capital and operational cost and local or global externalities, the latter when part of an internal agreement:[26]
    i) This could include alternatives with higher capital cost leading to negative net present values
    ii) Alternatives with combination of capital and fuel cost leading to more uneconomic projects if compared to others
    iii) Others properly assessed by teams as part of project appraisal to the extent methodologies are available
4) **Legal or regulatory barriers.** Specific legal or regulatory requirements may exist that cannot be sensibly implemented in the context of the project, or specific legal or regulatory impediments to the alternative project(s) may exist:
    i) The alternative project or mix may require land that cannot be legally used for the project activities.
    ii) The specific alternative technology may not be legally permitted in the country (for example, nuclear power).
    iii) The alternative may require agreements among stakeholders that potentially cause protracted

26 As described in the World Bank's operational policy on economic evaluation of investment operations (OP 10.04).

delays, making implementation of the alterative infeasible within the project timeframe, such as implementing international legal agreements for cross-border fuel transport and power trading; environmental and safety standards; international waterways; costs, risks and benefit sharing; and multipurpose projects.

iv) There may be other barriers assessed by teams as part of project appraisal.

Annex 3A: Manual: Excel Tool for New Power Generation Projects

This manual describes a tool that teams can use to calculate GHG emissions in generation projects following the principles and concepts presented in this chapter. The tool is an Excel workbook with various tabs to assist in the process, but its use is not mandatory. Teams can perform their calculations using their own model/tools or their consultants' tools, as long as the guidance in this note is followed. The steps to compute GHG emissions for the project and the baseline using the tools can be summarize as follows:

Step 1. Enter the project type and description.
Step 2. Select the methodology to establish the counterfactual (baseline).
Step 3. Establish the counterfactual (baseline).
Step 4. View the results for gross and net emissions.

- For ease of use, a "Hide Non-Relevant Cells" button can be activated, and only the necessary inputs are shown once the project type and the counterfactual baseline methodology are chosen.

Each step is explained below.

Step 1. Enter the project type and description

- Open workbook and go to the "MASTER" sheet. The purpose of the sheet is to compute emissions in the new generation project and the counterfactual, or the baseline.
- The difference between these two is the net emissions.
- Following the guidance, the decision tree (see Figure 3.1) should be used to choose which module to use to calculate generation emissions.
- For the project
  - Input the project type (cell C1).
  - Click on the "Hide Non-Relevant Rows" button.
  - Check default values and change if necessary in C4 to C7, E4 to E7, and G4 (if applicable).

Figure 3A.1: Input main project data

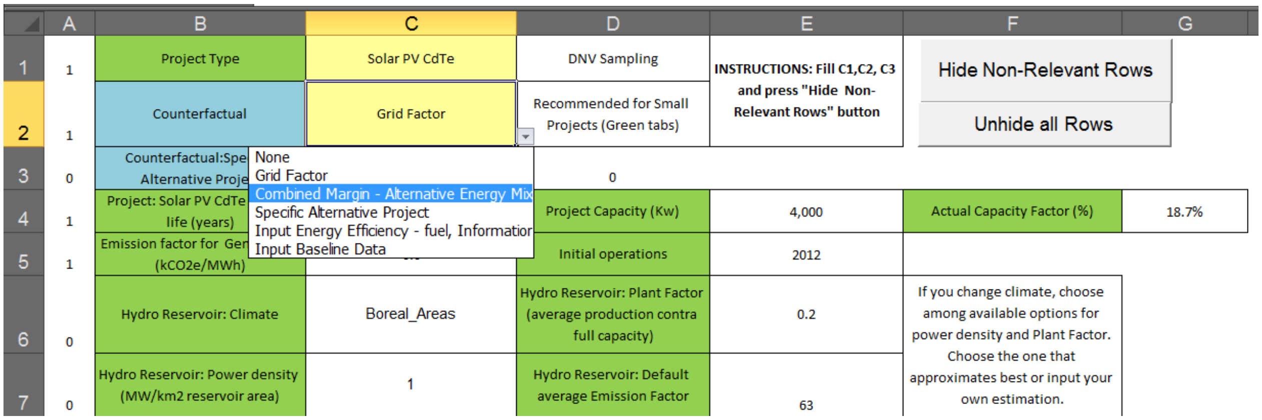
	A	B	C	D	E	F	G
1	1	Project Type	Solar PV CdTe	DNV Sampling	INSTRUCTIONS: Fill C1,C2, C3 and press "Hide Non-Relevant Rows" button	Hide Non-Relevant Rows	
2	1	Counterfactual	Grid Factor	Recommended for Small Projects (Green tabs)		Unhide all Rows	
3	0	Counterfactual:Specific Alternative Project	ThermalHeavy Fuel Oil	0			
4	1	Project: Solar PV CdTe Useful life (years)	30	Project Capacity (Kw)	4,000	Actual Capacity Factor (%)	18.7%
5	1	Emission factor for Generation (kCO2e/MWh)	0.0	Initial operations	2012		
6	0	Hydro Reservoir: Climate	Boreal_Areas	Hydro Reservoir: Plant Factor (average production contra full capacity)	0.2	If you change climate, choose among available options for power density and Plant Factor. Choose the one that approximates best or input your own estimation.	
7	0	Hydro Reservoir: Power density (MW/km2 reservoir area)	1	Hydro Reservoir: Default average Emission Factor	63		

- If the project is "Hydro Electric Dam," cells C6, C7, and E6 must also be filled in.

Step 2. Select the methodology to establish the counterfactual (baseline)

- Using Figure 3.1, input the counterfactual methodology in cell C2.
- Press the “Hide Non-Relevant Rows” button (Cells F1–F2).

Figure 3A.2: Project and counterfactual inputs



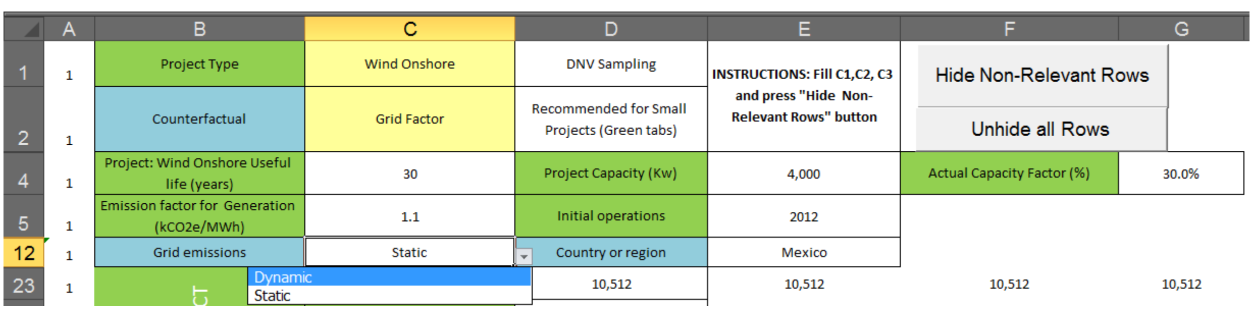
Step 3. Establish the counterfactual (baseline)

Depending on the sub-option selected, establish the counterfactual as follows.

A) Grid Factor

- Define the grid factor: Fill C12 (static or dynamic emissions) and E12 (country).

Figure 3A.3: Define grid factor



B) Combined Margin

- Define combined margin factors. Fill cell C11 for percentage (%) Build Margin. Cell E11 for % Operating Margin fills automatically.
  - For thermal projects, enter
    Operating margin factor = 50%
    Build Margin Factor = 50%
  - For all renewable energy projects, enter
    Operating Margin factor = 75%
    Build Margin = 25%

Figure 3A.4: Define build and combined margin parameters

	B	C	D	E	F
11	Combined Margin: % **Build** Margin	75%	Combined Margin Counterfactual: Operating Margin	25%	Input a Value between 0 and 100 in **BUILD** Margin

- For the build margin, select up to five generation options in C16–C20.
- Specify the "weight" of each alternative in cells D16–D20.

Figure 3A.5: Project weights (all equal shares by default)

	B	C	D	E	F
11	Combined Margin: % **Build** Margin	75%	Combined Margin Counterfactual: Operating Margin	25%	Input a Value between 0 and 100 in **BUILD** Margin
12	Grid emissions	Static	Country or region	Mexico	
13			Year	2012	2013
14			Combined Factor Yearly Emission Factor	367	367
15			Mexico Grid Emission Factor (Operating Margin)	505.7	505.7
16	1	Gas Combined Cycle w/o CCS	20%	469.0	469.0
17	2	Solar PV a-Si	20%	0.0	0.0
18	3	Coal Ultra-supercritical PC w/CCS	20%	94.0	94.0
19	4	Coal Subcritical PC w/o CCS	20%	931.0	931.0
20	5	Coal Supercritical PC wCCS	20%	109.0	109.0
21		Build Margin (Weighted Average)	100%	320.6	320.6

C) Approximate Alternative Mix

- Set Operating Margin in cell E11 to 0%
- Check values and replace accordingly in rows 16-20
  - Specify the "weight" of each alternative, up to five, in cells D16 to D20, ensuring that they total 100%.

D) Specific Alternative Project.

- Select the alternative project in cell C3

Figure 3A.6: Specific alternative input

	B	C	D	E	F	G
1	Project Type	Wind Onshore	DNV Sampling	**INSTRUCTIONS: Fill C1,C2, C3 and press "Hide Non-Relevant Rows" button**	Hide Non-Relevant Rows	
2	Counterfactual	Specific Alternative Project	Based in fuel sources, if several sources choose Input Baseline Data		Unhide all Rows	
3	Counterfactual:Specific Alternative Project	ThermalHeavy Fuel Oil	0			
4	Project: Wind Onshore Useful life (years)	30	Project Capacity (Kw)	4,000	Actual Capacity Factor (%)	30.0%
5	Emission factor for Generation (kCO2e/MWh)	1.1	Initial operations	2012		
10	Emission factor for Generation (kCO2e/MWh)ThermalHeavy Fuel Oil	793.0				

E) Full Assessment of options

- Obtain annual emissions (kgCO_2e/year) for the counterfactual from an external modeling tool and enter in row 29.

Figure 3A.7: User input (from external modeling) baseline

	B	C	D	E	F
23	PROJECT	Mwh/year Generation	10,512	10,512	10,512
24		Generation Emissions (kCO2e/year)	11,563.20	11,563.20	11,563.20
25		Total Project Electricity Generation (Mwh)	325,872	Total Generation Emissions kCO2e	358,459
26	COUNTERFACTUAL	Combined Emissions Factor	302.39	366.88	366.88
27		Mexico Grid factor (tCO2e/Mwh)	505.7	505.7	505.7
28		Mitigated Carbon (tCo2e/year)	3,167	3,845	3,845
29		Counterfactual Emissions (kgCo2e/year)	3,178,697	3,856,590	3,856,590
30		Total Counterfactual Emissions (kgCo2e)	94,991,162		
31	RESULTS	Total Project Lifetime abatement (tCO2e)	94,633	Average yearly abatement (tCO2e)	3,154

Step 4. View the results for gross and net emissions

- Cell D24 reports annual project emissions.
- Cell D25 reports total electricity generated in the project.
- Cell F25 reports total emissions associated with generation in the project.

Figure 3A.8: Project Report

	B	C	D	E	F
23	PROJECT	Mwh/year Generation	10,512	10,512	10,512
24		Generation Emissions (kCO2e/year)	11,563.20	11,563.20	11,563.20
25		Total Project Electricity Generation (Mwh)	325,872	Total Generation Emissions kCO2e	358,459

- Cells D26 to D30 report counterfactual (baseline) statistics and emissions.

Figure 3A.9: Baseline report

	B	C	D	E	F
26	COUNTERFACTUAL	Mexico Grid Emision Factor (kgCo2e/Mwh)	100.00	505.70	505.70
27		Mexico Grid factor (tCO2e/Mwh)	505.7	505.7	505.7
28		Mitigated Carbon (tCo2e/year)	1,040	5,304	5,304
29		Counterfactual Emissions (kgCo2e/year)	1,051,200	5,315,918	5,315,918
30		Total Counterfactual Emissions (kgCo2e)	160,528,752		

- Results are presented in D31 and F31

Figure 3A.10: Final results

	B	C	D	E	F
31	RESULTS	Total Project Lifetime abatement (tCO_2e)	160,170	Average yearly abatement (tCO_2e)	5,339

- If negative, the project increases net emissions.

Annex 3B: Examples

Important Note: These examples are for illustrative purposes only. They are not intended to reflect the actual emissions as calculated by teams, since this project was appraised before the corporate requirement. Assumptions will be made for the illustrative purposes of showing the application of the guidance note and to complement information that may have not been available in PADs, but that may have been available to teams in additional project documents such as feasibility studies. Assumptions made are for the purposes of illustrating the application of the guidance note and may be different from the prevailing conditions and information available at the time of appraisal.

Example 3B.1: Natural Gas Power Plant

Name:	Helwan South, supercritical steam plant fired by natural gas
Country:	Egypt
Installed capacity:	1,950 MW
Expected output:	11,626 GWh/year
Economic life span:	30 years

Since this is a large project, it is assumed that an analysis of alternatives and/or a power system planning modeling approach was available during the appraisal. The project alternatives may have been clearly identified in the project, or the least-cost planning could provide a description of other potential alternatives to the project, which would be used to define the project baseline.

Calculation of Project Emissions

The economic analysis and detailed project description annexes of the PAD list some of the important characteristics of the plant that are required to calculate the project emission. This includes the plant heat rate and an estimation of the plant emission factor (EF).

Plant heat rate = 8450 Btu/kWh
Plant EF = 463 kgCO_2/kWh[27]

The EF reported in the PAD is used to compute the project emissions. The Excel workbook provides a calculation cell to compute project emissions when heat rate, efficiency, or actual emission data are available. Based on the expected production reported in the PAD, the project emissions are computed as follows:

Total project emissions for a 30-year period = 11,626×463×30 = 161.485 million tCO_2e

Calculation of Baseline Emissions

Baseline generation emissions

[27] The emission factor was calculated using the methodology developed by the Inter-American Development Bank for GHG accounting for thermal power plants.

In the economic analysis section of the PAD, a screening curve analysis serves as a proxy for a power system model to determine whether the project is part of the least-cost plan. Since the project has already been appraised, we use such analysis to approximately determine what would be the basket of alternatives to the project.

The screening curve shows that for mid- and peak power plants (such as the project being supported), the next options in cost order are steam turbines running on gas, simple-cycle gas turbines, and finally heavy fuel oil (HFO) units. The dispatch analysis conducted by the project concludes that 700 MW of HFO will be retired with the addition of the project. The screening curve analysis and the dispatch analysis are used to approximate a basket of alternatives that delivers the same expected energy patterns as the project. For the purposes of this illustration, the alternatives mentioned in the PAD are assumed the most likely. Table 3B.1 summarizes the output required from the alternative mix to achieve an output similar to the project. Because the remaining life of the HFO plant that will not be shut down in the absence of the project is less than 30 years, an alternative needs to be identified for the remainder of the economic life of the project. For the purpose of this illustrative example, it is assumed that HFO of the same size and efficiency will continue to be installed.

Table 3B.1: Alternative mix and emissions

Basket	Type	Capacity (MW)	EF (gCO_2/kWh)	Energy peak (GWh)	Energy base (GWh)	CO_2 ($KtCO_2$)
Technology 1	HFO	700	677	441	3,974	2,989
Technology 2	Steam gas	1,000	463	2,018	3,027	2,336
Technology 3	Simple gas turbine	250	617	177	414	365
Grid electricity			558	545	1,028	878
Total		1,950	566	3,182	8,443	6,568

The total energy provided by the basket is equal to the project output. The grid electricity is a dummy (slack variable) that is required to ensure that a feasible basket is always found. It is recommended that grid electricity be no more than 10 percent of total output of the project. A share of grid electricity above 10 percent would signal that another project needs be added to the mix to provide a similar level of service.

The baseline emissions are 11,626×566×30 = 197.409 million tCO_2e, where 566 gCO_2/kWh is the emission rate of the baseline from the above table (6,568/11,626 x 1,000).

Calculation of Net Emissions:

⇨ **NET EMISSIONS = 161.485 – 197.409 = -35.924 million tCO_2e**

Example 3B.2: Concentrated Solar Power

Name:	Ouarzazate, CSP
Country:	Morocco
Installed capacity:	145MW
Produced power:	377 GWh/year
Economic life span:	25 years

Calculation of Project Emissions

Inputting these project parameters into the Excel workbook produces the following results for project emissions:

Total project emissions = 0.097 million tCO_2e

These are relatively low operational emission from CSP (Scope 2) projects[28].

Calculation of Baseline Emissions

Baseline generation emissions

Because the project represents a large addition, an analysis of alternatives is expected. The economic analysis of this project used the inputs from a power system model to determine the mix that would be replaced by the solar plant. Information in the PAD states that the alternative power production would be a mix of a coal plant, combined-cycle gas plant, and an oil plant. The size and production of the alternatives were clearly identified by means of power system modeling. The PAD includes the emission factors, electricity displaced, and resultant baseline emissions for each option in the mix, as shown in Tables 3B.2 and 3B.3.

Table 3B.2: Emission rates of power plants in Morocco

Tonnes per GWh	CO_2	SO_2	NO_x	PM
Coal plant	987	6.6	6.7	3.7
Combined Cycle	406	0.0	0.0	0.0
Oil plant	592	14.0	2.4	0.0

Source: World Bank. 2011. "Morocco - Ouarzazate Concentrated Solar Power Project." Washington, DC. http://documents.worldbank.org/curated/en/2011/10/15485420/morocco-ouarzazate-concentrated-solar-power-project.

[28] Default parameters in tools from data collected by DNV-KEMA based on recent assessment of life-cycle emissions from solar thermal technologies.

Table 3B.3: Electricity displaced and avoided emissions

	Electricity displaced (GWh)[23]	Avoided CO2 emissions (tons)	Value of CO2 emissions (US$ million)	Value of other emissions (US$ million)
Coal	69	68,112	2.0	0.7
Natural gas	55	22,284	0.7	0.0
Fuel Oil	253	149,973	4.5	1.6
Total	377	240,369	7.2	2.3

Source: World Bank. 2011. "Morocco - Ouarzazate Concentrated Solar Power Project." Washington, DC. http://documents.worldbank.org/curated/en/2011/10/15485420/morocco-ouarzazate-concentrated-solar-power-project.

Total baseline emissions = 6.009 million tCO_2e

Calculation of Net Emissions

⇨ **NET EMISSIONS = 0 – 6.009 = -6.009 million tCO_2e**

This is one case where all parameters are available from power systems modeling.

Example 3B.3: Wind Energy Power Plant

Name: La Venta
Country: Mexico
Installed capacity: 83.3 MW
Produced power: 308 GWh/year
Economic life span: 20 years

Calculation of Project Emissions

Inputting these project parameters into the Excel tool produces the following results for project emissions over a 20-year period:

Total project emissions = 0.007 million tCO_2e

These are predominantly emissions from operating the wind power plant (Scope 2) based on emission factors report in the literature.

Calculation of Baseline Emissions

Baseline generation emissions

Since this is a medium-size project (falling between 15 MW and 150 MW), the combined margin approach should be used in the baseline calculations.

This is a project where climate financing is being sought. In such cases, an established methodology may have been used to estimate emissions. This particular project is registered under CDM, and the PAD contains expected emissions reductions according to the CDM registration, estimated at 3.8 tCO_2e for the life of the project. That being the case, as the guidance note states, the emissions estimation from the CDM methodology should be used for reporting to meet the WBG GHG emissions accounting requirement.

For illustrative purposes, we present how the simplified methodology in the guidance note would be applied if the project were not registered under CDM.

For all renewable energy projects, the combined margin approach is as follows:

Baseline emission factor = 75% operating margin factor + 25% build margin factor

The operating margin emission factor for Mexico (which is available in the Excel workbook) is as follows:

Operating margin emission factor = 506 gCO_2/kWh

To determine the build margin emissions, we follow the PAD that states that combined-cycle gas turbines (CCGT) are the generation sources that have been recently added to the system. The default emission factor for CCGT available in the Excel workbook for use (if country-specific efficiency data are not available) is:

CCGT emission factor = 352 gCO_2/kWh

With that and the expected energy production of the plan, the baseline emissions over a 20-year period are calculated:

$308 \times (352\times25\% + 506\times75\%) \times20 = 2.941$ million tCO_2e

Finally, net emissions are calculated:

Calculation of Net Emissions

⇨ **NET EMISSIONS = 0.007 – 2.941 = -2.933 million tCO_2e**

The following figures illustrate the implementation of this example using the tool made available with this first version of the guidance note.

Figure 3B.1: Project Data

	B	C	D	E	F	G
1	Project Type	Wind Onshore	DNV Sampling	INSTRUCTIONS: Fill C1,C2, C3 and press "Hide Non-Relevant Rows" button	Hide Non-Relevant Rows	
2	Counterfactual	Combined Margin - Alternative Energy Mix	Recommended for Medium Projects		Unhide all Rows	
4	Project: Wind Onshore Useful life (years)	20	Project Capacity (Kw)	83,300	Actual Capacity Factor (%)	45.0%
5	Emission factor for Generation (kCO2e/MWh)	1.1	Initial operations	2012		
22			2012	2013	2014	2015
23		Mwh/year Generation	308,000	308,000	308,000	308,000
24		Generation Emissions (kCO2e/year)	338,800.00	338,800.00	338,800.00	338,800.00
25		Total Project Electricity Generation (Mwh)	6,776,000	Total Generation Emissions kCO2e	7,114,800	

Figure 3B.2: Combined Margin Parameters

11	Combined Margin: % **Build** Margin	25%	Combined Margin Counterfactual: Operating Margin	75%	Input a Value between 0 and 100 in **BUILD** Margin	
12	Grid emissions	Static	Country or region	Mexico		
13			Year	2012	2013	2014
14			Combined Factor Yearly Emission Factor	467	467	467
15			Mexico Grid Emission Factor (Operating Margin)	505.7	505.7	505.7
16	1	Gas Combined Cycle w/o CCS	100%	352.0	352.0	352.0
17	2	Solar PV a-Si	0%	0.0	0.0	0.0
18	3	Coal Ultra-supercritical PC w/CCS	0%	94.0	94.0	94.0
19	4	Coal Subcritical PC w/o CCS	0%	931.0	931.0	931.0
20	5	Coal Supercritical PC wCCS	0%	109.0	109.0	109.0
21		Build Margin (Weighted Average)	100%	352.0	352.0	352.0
22			2012	2013	2014	2015
23		Mwh/year Generation	308,000	308,000	308,000	308,000
24		Generation Emissions (kCO2e/year)	338,800.00	338,800.00	338,800.00	338,800.00
25		Total Project Electricity Generation (Mwh)	6,776,000	Total Generation Emissions kCO2e	7,114,800	
26	COUNTERFACTUAL	Combined Emissions Factor	467.28	467.28	467.28	467.28
27		Mexico Grid factor (tCO2e/Mwh)	505.7	505.7	505.7	505.7
28		Mitigated Carbon (tCo2e/year)	143,582	143,582	143,582	143,582
29		Counterfactual Emissions (kgCo2e/year)	143,920,700	143,920,700	143,920,700	143,920,700
30		Total Counterfactual Emissions (kgCo2e)	2,941,022,700			

Figure 3B.3: Final Results

RESULTS	Total Net Emissions (tCO2e)	-2,933,308	Average yearly abatement (tCO2e)	-146,665

4. Hydropower

This chapter deals with emissions from hydropower generation project, both for greenfield and rehabilitation. Pumped storage is not covered in this version of the guidance note. The chapter incorporates the concepts from the previous chapter on power generation project and elaborates on how emissions from reservoirs should be considered in GHG accounting. While this is a stand-alone chapter on hydropower, it is strongly recommended that the main concepts and principles found in chapters 1 and 3 be reviewed in addition.

4.1 Typology of Hydropower Projects

World Bank hydropower projects are associated with building new or refurbishing existing hydropower plants. Hydropower projects can be single purpose (solely for electricity generation) or multipurpose (combining electricity generation with, for example, flood control and/or water supply for domestic use and irrigation). The objectives of these projects in World Bank interventions typically include expanding the electricity generation capacity and bringing associated benefits, such as climate change adaptation or improved livelihood for local communities.

Greenfield hydropower with reservoir involves the construction of a dam with significant storage for regulation, a power plant, and a transmission line to evacuate the power to the existing grid. This would increase power generation and potentially give multipurpose benefits through the joint reservoir operation for other purposes. The main factors affecting GHG emissions are the change (replacement) in electricity generation, GHG emissions from biochemical processes in the reservoir from decomposition of organic material, and emissions associated with construction of the dam and power plant.

Greenfield run-of-river hydropower involves the construction of a small intake dam with negligible storage (the main purpose of a low dam or weir is to guarantee a minimum water level), a power plant, and a transmission line to evacuate the power to the existing grid. This would mainly increase power generation. The main factors affecting GHG emissions are the change (replacement) in electricity generation and emissions associated with construction of the power plant.

Rehabilitation or retrofitting of existing hydropower or hydraulic infrastructure involves the replacement or addition of new equipment in an existing hydropower plant (most often electromechanical units). This would increase power generation from improved efficiency of electromechanical equipment and/or additional units. The main factors affecting GHG emissions are the change (replacement) in electricity generation and emissions associated with rehabilitation/construction of the power plant.

Small-scale hydropower programs involve support to micro- or mini-hydropower schemes (usually smaller than 5 MW), which normally are small run-of- river projects with limited hydraulic infrastructure. The main factor affecting GHG emissions is the change (replacement) in electricity generation; GHG emissions generated from construction are very small in most cases.

Pumped storage hydropower involves a scheme that utilizes cheap energy during off-peak times to pump water to a higher storage site, and release the water to produce power during high peak times. The net energy produced is negative because of efficiency losses in the pumping and generation. The pumped storage itself creates very limited GHG releases in connection with construction, while operating emissions vary greatly, depending on the source of the power used for pumping during off-peak. Normally this would be typical base load sources, such as coal, nuclear, or hydropower, but can also be wind or solar. Because of the large complexity of calculating both the emissions for pumping and the baseline for replacing the high peak load, and because pumped storage projects are relatively rare among World Bank projects, GHG emissions accounting is not yet required for pumped storage hydropower, awaiting research and development of a methodology.

4.2 Project Boundaries

Net emissions associated with hydropower projects are affected by those occurring within the direct physical boundaries of the project intervention and those associated with generation in the baseline. The physical boundaries for the project would include the reservoir area (if the project includes a reservoir), the dam and power plant sites, construction and quarry sites, access roads, and transmission corridors. Only emissions that occur inside the direct physical boundaries of the hydropower facilities' being supported by the project will be considered project emissions.

For greenfield hydropower projects with reservoirs, the emissions created by the changed biochemical processes caused by damming the river and filling terrestrial areas with water must be considered in a catchment perspective, because the creation of the reservoir also changes the natural emissions in rivers and lakes downstream. For GHG accounting purposes, however, the project emissions created by biochemical processes associated with the reservoir are assigned to the physical reservoir area, although the effects on the emissions in the downstream catchment area are taken into account.[29]

4.3 Sources of Emissions

Five sources of emissions are considered, listed in order of decreasing expected magnitude:

1*. Emissions from changed generation.* Impacts on GHG emissions result from increases in electricity generation replacing other energy sources. Since hydropower is a renewable and long-lasting energy source, it will create a net difference in emissions and replace other sources with (often) higher emission factors.

2*. Emission caused by biochemical processes when a reservoir is introduced.* When a river is dammed, the flow dynamics are changed, riverine sediment and organic material are trapped, and terrestrial ecosystems are flooded. This alters the previous cycle and fluxes of CO_2 and other GHGs within the project footprint. The main contributions to emissions are decomposable parts of flooded soil and

[29] See further details in the World Bank Interim Technical Note for GHG from Reservoirs Caused by Biochemical Processes, Water Papers, April 2013. http://documents.worldbank.org/curated/en/2013/04/17658689/greenhouse-gases-reservoirs-caused-biochemical-processes-interim-technical-note.

vegetation in terrestrial zones and removed sinks from cleared biomass growth. GHG emissions from new aquatic systems will occur during the full lifetime of the reservoir, but will exponentially decrease as the flooded organic material is decomposed and as biochemical conditions change.

The next three sources have a relatively small impact compared to the impacts of lifetime emissions from a hydropower project. Their computation is optional if the required input information is not readily available.

3*. Land clearing for civil works and transmission lines.* New construction of dams, headrace tunnels, power plants, access roads, and transmission lines[30] require land clearing. Some of this land clearing will be permanent, while many areas cleared during construction will have regrowth of vegetation shortly after commissioning. The permanently affected areas are generally small.

4*. Embodied emissions in construction materials.* The construction of hydropower projects consumes concrete, metals, and other building materials. All of these materials have embodied emissions as a result of the energy used to produce them, meaning that the implementation of hydropower projects creates some upstream emissions in the manufacture of the materials used. Besides the expected low emissions relative to other project emissions, estimating such emissions would require ex ante knowledge of the place where the equipment will be manufactured, which in the context of the World Bank's project procurement practices is not available during project appraisal.

5*. Energy use in construction.* There is energy use in the construction of infrastructure for a hydropower project, primarily in the form of transport fuel for construction vehicles and the shipping of components.

4.4 Computing Gross and Net Emissions

Net emissions are calculated as the difference between project and baseline emissions, as in the example in Table 4.1.

Table 4.1: Illustrative net emission calculation for hydropower projects (tCO_2e)

	Baseline	Project	Net
Emissions from changed generation	32,81	0	-32,81
Net reservoir emissions	0	1.53	1,53
Land clearing (not incl. reservoir)	0	0.06	0.06
Embodied emissions and energy in construction	0.09	0.12	0.03
Total emissions	32,90	1.71	**-31,19**

Note: The numbers are for illustrative purposes only, taken from the Trung Son example presented in Annex 4C.

[30] Transmission lines are listed here because, unlike many other generation plants, hydropower plants tend to be built in remote areas, far from the existing grid and hence requiring longer transmission lines.

4.5 Defining the Baseline

The baseline, or alternative or counterfactual to the project intervention, is not a "no-project," but rather a project that provides the same level of service for the end user (for example, same electrification rate or level of output in terms of energy) as the project being pursued.

Table 4.2 provides guidelines for the baseline and calculation of project emissions for hydropower projects with different objectives:

Table 4.2: Hydropower project objective and baseline emissions

Project objective	Baseline and project emissions
Greenfield reservoir and run-of-river hydropower, large and small scale	The alternative to these greenfield hydropower projects would be to generate the same amount of power from another source. What is essential to note is that the same level of service is not measured only in annual electricity production. Reservoir hydropower is most often used to produce peak load, which can be produced only by limited types of energy sources. It may therefore be that the least-cost alternative to a reservoir hydropower project is a combination of other energy sources (for example, a run-of-river combined with a combined-cycle gas turbine plant). The definition and calculation of baseline emissions for greenfield hydropower projects should follow the general guidelines for new generation projects in chapter 3, except in the case of reservoir hydropower projects. The reservoir emissions caused by biochemical processes for greenfield hydropower reservoir projects should be calculated for the entire lifetime of the dam infrastructure set to 100 years by the IPCC. The reason is that the science does not yet allow for the estimation of net biochemically generated emissions for less than the full life span, and because it is unlikely that the dam would be decommissioned at the end of the economic life of the hydropower plant. Annex 4B has default emission factors for reservoir emissions based on a lifetime of 100 years. The emissions associated with generation in the baseline are calculated for the life of alternative energy sources rather than for 100 years, because of the difficulties in forecasting emission characteristics of technologies a century into the future. This approach would under-estimate net emissions substantially when compared on a lifecycle basis if the baseline includes generation based on fossil fuels, making the methodology conservative. In the case of a new reservoir being built, the baseline is no new reservoir. The baseline emissions from biochemical processes in the baseline in that case are set to zero in this guidance note. The reason is that the natural emissions occurring in a no-reservoir situation are taken into account to calculate the "net biochemical emission" when a reservoir is introduced. Emissions from land clearing can be calculated as a one-time emission of CO_2 based on the available dry biomass carbon for the total cleared areas for construction, according to IPCC guidelines. For run-of-river projects, where the reservoir area is so small that the biochemical emissions during the lifetime of the projects can be assumed to be zero, the reservoir area can be added to the land-clearing area for construction and be calculated as a one-time emission. Life-cycle analyses of hydropower documents in literature show a mean value of 2.9 $kgCO_2e/MWh$ (minimum 0.2, maximum 11.2) for hydropower, excluding reservoir emissions, which can be used as default value for the embodied emissions and

Project objective	Baseline and project emissions
	energy use for construction if no other information is available.
Rehabilitation or retrofitting of hydropower units in existing plants and hydraulic infrastructure	The likely alternative in the rehabilitation case is the continuation of the current situation, whereby the existing technical losses continue to increase because of old electromechanical equipment, requiring more generation to be injected into the grid to continue providing the same level of service to the final consumer. Annex 4A provides further illustration of the methodology of calculating baseline emissions for hydropower rehabilitation projects. In the case of retrofitting hydropower units on existing hydraulic infrastructure, the baseline would be similar to a greenfield project, which is an alternative source to generate the same amount of power. If the rehabilitation or retrofitting is carried out on an existing dam, the introduction of upgraded or new power units would have little effect on the emissions from the existing reservoir. In most dams, the majority of emissions occur during the first part of the lifetime, and reservoir emissions from biochemical processes would have subsided to essentially zero by the time of rehabilitation. Reservoir emissions are thus not relevant for this typology of hydropower projects, which is another way of stating that emissions from reservoirs during the entire lifetime of the dam are largely accounted for in greenfield hydropower reservoir projects (previous project category in this table). Since rehabilitation and retrofitting most often involve primarily installation of electromechanical equipment, the construction and land-clearing emissions are minimal. Only if significant civil work or land clearing is associated with the rehabilitation or retrofitting do these GHG sources need to be calculated.
Greenfield multipurpose reservoirs	There are basically two cases of multipurpose dams: • The first is where hydropower generation is the main purpose (the primary priority in operation) for construction of the reservoir, but where the created storage is used for flood protection or limited water supply, which can be provided without affecting electricity production markedly. • The second is where the primary purpose of the reservoir is something other than power generation, such as irrigation or flood protection, but hydropower (secondary priority in operation) is produced when water is released. In both cases, the baseline is similar to a greenfield single-purpose project, which is an alternative source of the same amount of power generation. Since the installed turbine capacity and the produced electricity would in both cases be less than optimum (compared to a single-purpose project), the baseline for reservoir emissions would be different from zero. • In the first case, the baseline emissions would in theory be the emissions from a reservoir that would produce the same ancillary services. In practice this is normally very complex to calculate, and hence it is recommended that the baseline emissions be set equal to zero, conservatively assuming that all reservoir emissions are assigned to the hydropower component. • In the second case, the baseline reservoir emissions would be the same as the project emissions (since the reservoir would be built even without hydropower generation), thus making this emission source not relevant for this typology of hydropower projects. That is, for the purpose of GHG accounting, zero reservoir emissions are assigned to the hydropower component.
Sources: IPCC (Intergovernmental Panel on Climate Change). 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories,* Geneva. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.	

Project objective	Baseline and project emissions
H. L. Raadal, I. Gagnon, I. S. Modahl, and O. J. Hanssen. 2011. "Life Cycle Greenhouse Gas (GHG) Emissions from the Generation of Wind and Hydro Power." *Renewable and Sustainable Energy Reviews* 15:3417–22.	

4.6 Indicative Emissions Patterns

Table 4.3 shows most likely or typical outcomes of incremental emissions from various types of hydropower projects.

Table 4.3: Indicative emission patterns for hydropower projects

Project objective	Most likely overall net emissions impact
Greenfield hydropower with reservoir	Reduction (-) since the alternatives to produce peak load are almost exclusively fossil fuel (gas, fuel oil, or diesel), and the reservoir emissions caused by biochemical processes are almost in all cases low compared to these alternatives. If a project is designed for multipurpose usage of the reservoir and power generation is not the primary objective, the net impact is an ever larger reduction, since the possible increased emissions because of biochemical processes are not assigned to the power production.
Greenfield run-of-river hydropower	Reduction (-) unless the least-cost alternative is another renewable energy, in which case the impact may be neutral (0).
Rehabilitation or retrofitting of existing hydropower or hydraulic infrastructure	Reduction (-).
Small-scale hydropower programs	Reduction (-) unless the least-cost alternative is another renewable energy, in which case the impact may be neutral (0).

Annex 4A: Hydropower Rehabilitation Projects

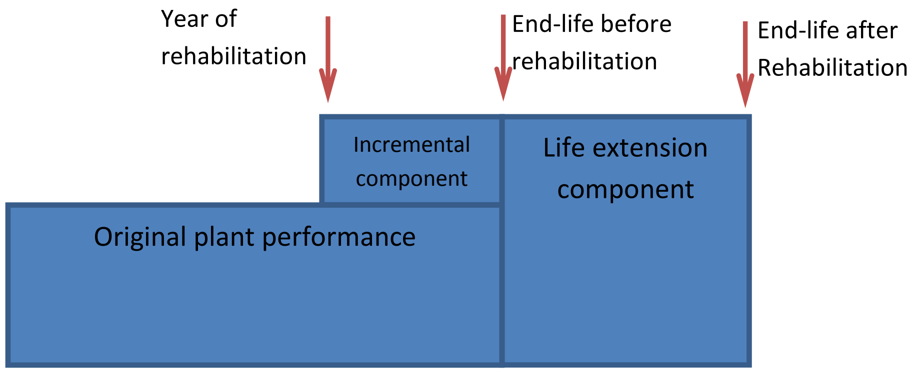
Rehabilitation (or retrofitting) of an existing hydropower infrastructure involves replacement or installation of new equipment in that hydropower plant, resulting in increasing the energy output at the same or higher rated capacity through improved efficiency and performance of the hydropower plant. In addition, a rehabilitation project will usually extend the life of the power plant.

For the purposes of defining the electricity generation baseline for a hydropower project, the impacts of the rehabilitated plant can be characterized as having two components: (a) improved performance component (or incremental output), and (b) life extension component (capacity or generation extension) as follows (see Figure 4A.1).

Improved performance. Incremental electricity output and capacity from the time of rehabilitation up to the end of the economic life time of the original plant.

Life extension. Electricity output and capacity after rehabilitation up to the end of the extended life of the project.

Figure 4A.1: Representation of the rehabilitated plant by component



Note: Each rectangle's area illustrates energy, the height capacity, and the length of life in years.

The project's net emissions from generation are formulated as follows:

Net emissions = Project Emissions – (Improved Performance Baseline Emission + Life Extension Baseline Emissions)

The baseline for the improved performance and life extension components will be determined following the same guidance presented in Figure 4A.1 for any generation project and using the following considerations outlined:

For the improved performance component baseline:

- The equivalent capacity of the incremental performance component should be assumed as follows:
  Total Incremental Energy / (24 X 365 X production factor).

- The life of the incremental performance component is the remaining life of the plant before rehabilitation.

For the life extension component baseline:

- The equivalent capacity is the capacity of the rehabilitated power plant.
- The life is equal to the number of years gained with the rehabilitation.

The application of the considerations noted above is illustrated through the following example: A 100 MW hydropower plant's electromechanical equipment (4 sets of 25 MW generator/turbine groups) is replaced, and an additional 25 MW generator/turbine generation capacity is added to the dam. The remaining life of the plant, which was expected to be 5 years, is assumed to be extended by an additional 20 years without other major renovations.

The original 100 MW power plant was producing at an average 0.35 production factor (p.f). The expanded power plant with enhanced capacity of 125 MW is expected to have a production factor of 0.37 (hydrology and plant operation regime assumed to be unchanged).

With this, the improved performance component is modeled as follows:

A 25 MW plant operating at 0.37 p.f. for 5 years.

The life extension component is calculated as below:

A 125 MW plant operating at 0.37 p.f. for 20 years.

Using the flow charts in Figure 3.1 in chapter 3, the baseline emissions for each component are calculated using the following emission factors:

Improved performance component = 450 tCO_2e/MWh

Life extension component emissions = 350 tCO_2e/MWh

Under these assumptions, the net generation emissions are estimated below:

Net = 0 – [450 x (25 x 24 x 365 x 0.37) x 5 + 350 x (125 x 24 x 365 x 0.37) x 20]

Annex 4B: Default Emission factors for Reservoir Emissions

Tables 4B.1 shows default emission factors that can be used for calculating emissions from greenfield reservoirs. Values are averages for 100 years, the typical life span of a reservoir. These emission factors take into count natural emissions in a no-reservoir situation. If baseline emissions are calculated for such no-reservoir scenarios, natural emissions for the reservoir area need not be separately calculated for the baseline. For more details on how the default values below are calculated, see the "World Bank Interim Technical Note for Greenhouse Gases from Reservoirs Caused by Biochemical Processes," Water Paper, April 2013, http://documents.worldbank.org/curated/en/2013/04/17658689/greenhouse-gases-reservoirs-caused-biochemical-processes-interim-technical-note, referred to as the World Bank Interim Technical Note hereafter.

If the reservoir is extremely large compared to the installed capacity (power density is very low), the assumptions made in calculating the default emission factors may be too simplistic. In such cases, it is recommended that a more detailed assessment be carried out based on actual measurements of key variables. This is explained later in this annex.

All methodologies (tiers 1, 2, and 3 in Box 4B.1) are based on the principle of carbon stock estimation, which estimates how much carbon—that can potentially decompose and be emitted as GHGs to the reservoirs—is available in the future reservoir area. The difference in the level of detail in the different tiers refers to how the carbon stock is estimated.

Table 4B.1: Default Average Emission factors for GHG Emissions from Reservoirs

Default average emission factors for net emissions from reservoirs (EF_{Res}) based on World Bank Guidance note on GHG from Reservoirs caused by Biochemical Processes, Water Paper, April 2013. Default values calculated according to Tier 1.

Unit: kg CO_2-eqv/MWh

BOREAL AREAS		Plant Factor 0.2	0.4	0.6	0.8
Power density (MW/km2 reservoir area)	<0.25	Detailed assessment required			
	0.25	251	126	84	63
	0.5	126	63	42	31
	1	63	31	21	16
	2	31	16	10	8
	4	16	8	5	4
	6	10	5	3	3
	>6	Can be assumed zero			

TROPICAL SCRUB AREAS		Plant Factor 0.2	0.4	0.6	0.8
Power density (MW/km2 reservoir area)	<0.5	Detailed assessment required			
	0.5	255	127	85	64
	1	127	64	42	32
	2	64	32	21	16
	4	32	16	11	8
	7	18	9	6	5
	10	13	6	4	3
	>10	Can be assumed zero			

TROPICAL DRY AREAS		Plant Factor 0.2	0.4	0.6	0.8
Power density (MW/km2 reservoir area)	<1	Detailed assessment required			
	1	283	141	94	71
	2	141	71	47	35
	4	71	35	24	18
	7	40	20	13	10
	10	28	14	9	7
	25	11	6	4	3
	>25	Can be assumed zero			

TEMPERATE AREAS		Plant Factor 0.2	0.4	0.6	0.8
Power density (MW/km^2 reservoir area)	<1.5	Detailed assessment required			
	1.5	281	140	94	70
	2	211	105	70	53
	4	105	53	35	26
	7	60	30	20	15
	10	42	21	14	11
	20	21	11	7	5
	40	11	5	4	3
	>40	Can be assumed zero			

TROPICAL WET AREAS		Plant Factor 0.2	0.4	0.6	0.8
Power density (MW/km^2 reservoir area)	<2.5	Detailed assessment required			
	2.5	259	129	86	65
	4	162	81	54	40
	7	92	46	31	23
	10	65	32	22	16
	20	32	16	11	8
	40	16	8	5	4
	60	11	5	4	3
	>60	Can be assumed zero			

Source: Liden, Rikard. 2013. "Greenhouse gases from reservoirs caused by biochemical processes: interim technical note." Water papers, Washington DC, World Bank. http://documents.worldbank.org/curated/en/2013/04/17658689/greenhouse-gases-reservoirs-caused-biochemical-processes-interim-technical-note.

Box 4B.1: Different Tier Levels for Estimation of GHG Emissions from Reservoirs

Tier 1: Desk study based on Agriculture, Forestry and Other Land Use (AFOLU) stock estimate. Use available geographical information on the reservoir from feasibility and Environmental Impact Assessment (EIA) studies together with standard biomass, carbon content, soil, and litter carbon in AFOLU to estimate the amount of flooded organic carbon. Combine that estimation with interim assumptions given in the World Bank Interim Technical Note to estimate average GHG emissions over the life span of the reservoir.

Tier 2: Desk study based on more detailed stock estimates. Use available geographical information on the reservoir from feasibility and EIA studies together with local and regional databases on above-ground biomass, soil, and litter carbon.

Tier 3: Field studies. Use results from Tier 1 or 2 augmented by field measurements (plot tests) and laboratory analyses to estimate the carbon content in biomass, litter, and soil. This is similar to standard CDM methodology for deforestation.

Source: IPCC (Intergovernmental Panel on Climate Change). 2006. *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. Geneva. http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html.

Principal Steps for detailed assessment

When a detailed assessment is recommended, the following principal steps should be performed:

Step 1: If power density for the reservoir in given climate and vegetation zone is below the value for which default emissions are given in Table 4B.1, use the methodology recommended in section 5.2 of the World Bank Interim Technical Note to estimate reservoir emissions caused by biochemical processes and calculate the specific reservoir emissions (CO_2e/km^2 reservoir area).

Step 2: Choose Tier 2 as default, which applies actual estimates of forest or vegetation cover, vegetation types, and soil types in the carbon stock estimation. Use these actual values to calculate the total stock of carbon in the reservoir area through applying the average carbon content given in AFOLU, or preferably by using local or regional measurements and analysis for carbon content per biomass or soil unit. Such local information may be available, for example, if studies for CDM projects for nearby forestry have been carried out.

Step 3 (optional): If very limited information is available on the types of soil and vegetation in the reservoir area, or if AFOLU values are judged to be very uncertain, use Tier 3, which is for conducting field studies in the reservoir area. Such a study would be very similar to a study conducted for CDM projects for deforestation and should be conducted using relevant expertise. For GHG accounting purposes, step 3 is not required; it should be considered optional and conducted only if specifically requested by the client.

Annex 4C: Examples

Important Note: These examples are for illustrative purposes only. They are not intended to reflect the actual emissions as calculated by teams, since this project was appraised before the corporate requirement. Assumptions will be made for the illustrative purposes of showing the application of the guidance note and to complement information that may not have been available in PADs, but that may have been available to teams in additional project documents such as feasibility studies. Assumptions made for the purposes of illustrating the application of the guidance note may be different from the prevailing conditions and information available at the time of appraisal.

Example 4C.1: Greenfield Multipurpose Reservoir Hydropower

Name:	Trung Son
Country:	Vietnam
Purpose:	Mainly single-purpose for power generation, although the reservoir also contributes to flood management.
Installed capacity:	260 MW
Produced power:	1,019 GWh/year
Climate:	Tropical moist
Reservoir area:	13.1 km^2
Construction area:	2 km^2 (estimated)
Economic life span:	40 years

Calculation of Project Emissions

Reservoir emissions

Although partly multipurpose, the main purpose of the reservoir is power generation. In the simplified methodology for GHG accounting, all reservoir emissions are assigned to the hydropower component.

Plant factor = (1,019×1000) / (260×365×24) = 45%
Power density = 260/13.1 = 20 MW/km^2

Annex A ➔ Reservoir emission factor for 100 years = 15 $kgCO_2e$/MWh.

Total project reservoir emissions, assuming the dam exists for 100 years = 1,019×15×100 = 1.53 million tCO_2e. Note that the full life span for the dam infrastructure shall be the basis for project emissions in greenfield reservoir projects.

Land clearing

IPCC ➔ Tropical moist has 180 tons/ha of dry biomass, of which the average carbon content is 47%.

Conversion factor for carbon weight to CO_2weight = 44/12.

Total land clearing emissions for 2 km^2 = 2×180×100×0.47×44/12 = 0.06 million tCO_2e

Embodied material and energy emissions during construction

Default: 2.9 $kgCO_2e/MWh$

Total project construction emissions = 1,019×2.9×40 = 0.12 million tCO_2e

⇨ **Total project emissions = 1.53 + 0.06 + 0.12 = 1.71 million tCO_2e**

Calculation of Baseline Emissions

Baseline generation emissions

Information in the PAD states that the alternative power production will be a mix of coal and gas thermal production. The combined emission factor used by the PAD is 805 $kgCO_2e/MWh$.

The lifetime of the Trung Son project is assumed to be 40 years, which is also used to calculate the baseline project.[31]

Total baseline generation emissions = 805×1019×40 = 32.81 million tCO_2e

Baseline construction emissions

The default value for one-off emissions for thermal coal power per kW of installed capacity is 616 $kgCO_2e/kW$, and for gas 503 $kgCO_2e/kW$. Corresponding default plant factors are 65 percent and 85 percent for coal and gas, respectively.

Assuming an equal-mix installed capacity to produce 1,019 GWh/year gives 78 MW of coal and 78 MW of gas.

Totals baseline construction emissions = 616×78+503×78 = 0.09 million tCO_2e

⇨ **Total baseline missions = 32.81 + 0.09 = 32.90 million tCO_2e**

Calculation of Net Emissions

⇨ **NET EMISSIONS = 1.71 – 32.90 = -31.19 million tCO_2e[32]**

[31] Note that this is a conservative estimate, since all emissions from the reservoir for a 100-year period is assumed, and since a decommissioning of such a dam is not likely. This will provide an opportunity to rehabilitate the electromechanical equipment for this dam for the period, year 60 to year 100, which enables assumption of power production with zero emissions from the reservoir during this latter period.

[32] Note that not including the optional parts (land clearing and construction emissions) would give very similar net emissions, -31.28 million tCO_2e, well within the uncertainty range for the estimate of, for example, baseline emissions. These optional parts have nevertheless been included for illustrative purposes in this example.

Example 4C.2: Rehabilitation/Retrofitting Hydropower

Name:	Tarbela Fourth Extension
Country:	Pakistan
Purpose:	Single-purpose for power generation
Installed capacity:	1,410 MW
Produced power:	3,840 GWh/year
Climate:	Tropical dry
Construction area:	0.1 km^2
Economic life span:	30 years

Calculation of Project Emissions

Reservoir emissions

The project would support installation of hydropower units on the existing Tunnel number 4 of the Tarbela Dam. There will be no change in the dam height or area of the project. As such, the reservoir emissions caused by biochemical processes are considered negligibly small and not calculated.

Total project reservoir emissions = 0

Land clearing

IPCC ➔ Tropical moist has 130 ton/ha of dry biomass, of which the average carbon content is 47%.

Conversion factor for carbon weight to CO_2weight = 44/12

Total land clearing emissions for 0.1 km^2= 0.1×130×100×0.47×44/12 = 0.002 million tCO_2e

Embodied material and energy emissions during construction

A powerhouse will be constructed, so that limited construction emissions exist. A value of 1 $kgCO_2e$/MWh, which is on the lower end of the documented interval (0.2–11) in literature, is used.

Total project construction emissions = 3,840×1×30 = 0.115 million tCO_2e

- ⇨ **Total project emissions = 0.115 + 0.002 = 0.12 million tCO_2e**

Calculation of Baseline Emissions

Baseline generation emissions

Information in the PAD states that the alternative power production would be thermal gas power (CCGT). The standard emission factor for CCGT is 354 $kgCO_2e$/MWh.

Total baseline generation emissions = 354×3,840×30 = 40.78 million tCO_2e

Baseline construction emissions

The default value for one-off emissions (optional) for thermal gas power is 503 $kgCO_2e$/kW of installed capacity. The corresponding plant factor is 85 percent.

For the installed capacity to produce 3,840 GWh/year requires 516 MW of thermal gas power.

Totals baseline construction emissions = 503×516 = 0.26 million tCO_2e

⇨ **Total baseline missions = 40.78 + 0.26 = 41.04 million tCO_2e**

Calculation of Net Emissions

⇨ **NET EMISSIONS = 0.12 – 41.04 = -40.92 million CO_2e[33]**

[33] Note that with the optional parts (land clearing and construction emissions) not conducted, the net emissions would be very similar (-40.78 million tCO_2e). These optional parts have nevertheless been included for illustrative purposes in this example.

5. Demand-Side, Energy-Efficiency Projects

Demand-side management interventions can vary widely in terms of the sector being targeted (industry, residential energy consumption, buildings, service sector) and the type of instrument used (efficiency standards, more efficient technologies, pricing alternatives, incentives, consumption bans). This chapter covers only a narrow subset of demand-side energy interventions wherein the result is a reduction in the consumption of electricity from the grid. Substitution of efficient electric appliances and equipment for devices using fuels (such as efficient lighting replacing kerosene lamps) and improving efficiency of fuel-consuming appliances and equipment (such as more efficient non-electric cookstoves) are not covered.

The guidance note applies only to investment interventions (for example, support for installing more efficient equipment, such as air conditioning or more efficient lighting) and excludes regulatory or policy interventions, such as efficiency standards or pricing mechanisms. While the latter may have tremendous impacts on increasing energy efficiency, the methodology for estimating their effects on GHG emission has not yet been developed.

This is a stand-alone chapter on energy efficiency. However, it is recommended that the main concepts and principles found in the first chapter be reviewed in addition as well.

5.1 Typology of Projects

Following is a list of demand-side interventions that are covered in this guidance note, all drawing electricity from the grid:

- Efficiency lighting programs: residential, commercial, or street sectors.
- More efficient air conditioning systems.
- More efficient appliances, such as refrigerators, at the residential, commercial, or other consumption sectors.

5.2 Project Boundaries

The project boundaries are defined as the physical boundaries of the intervention: the less efficient assets being replaced by more efficient assets, plus any direct impacts on the grid, as per Scope 2 emissions. Scope 2 includes the electricity used by the equipment and any technical T&D losses up to the point where the device is installed. Scope 3 emissions, such as emissions from manufacturing and transporting the equipment, are not included. Some of these emissions cannot in fact be feasibly computed during project appraisal, since procurement of the equipment occurs at a later stage.

5.3 Sources of Emissions

It should be noted that only the emissions associated with electricity generation in the grid need be reported for the subset for demand-side, energy-efficiency intervention covered in this chapter.

1. Emissions from the change in the amount of electricity generated to meet the same need. The energy used by the project and the alternative to provide the same level of service. The service could be lighting, refrigeration, cooling, or others. Since the intervention may be located at the household, commercial, or industrial consumption level, the electricity used by the equipment will also be associated with T&D losses in the grid that need to be accounted for as part of the project boundaries.

The computation of the following is not required:

2. Embodied emissions in manufacturing and disposal. The manufacturing of the devices (appliances, bulbs) or other plus their transport and disposal after usable life.

5.4 Leakage, Usable Life, and De-rating

Replacing more efficient equipment can lead to increased energy use if the less efficient equipment being replaced continues to be used in another capacity. Most well-structured projects involving efficiency replacements for appliances have mechanisms to ensure that old appliances are retrieved from the household facilities and destroyed. This reduces the leakage impact considerably. Whenever there are design uncertainties in the project that may indicate that leakage could be an issue, teams need to assess the potential size of such leakage and add to the baseline estimation.

Efficient devices, such as lamps and refrigerators, require meeting certain internally recognized standards to ensure that a minimum life will be guaranteed. Teams should evaluate whether the devices installed follow such standards and use the expected life indicated by such standards when performing the accounting. The calculations should capture energy-efficiency characteristics of the appliance or equipment with use where applicable. For example, in some cases, efficiency standards allow for equipment degradation down to (at the most) 80 percent of its original rating—by the end of the life of the device, it will be 20 percent less efficient than at the beginning. If the device life is five years, a degrading factor of 4 percent per year should be used.

Using more efficient appliances could lead to lower expenditures on energy, potentially increasing total energy use as more budget becomes available. This rebound effect will depend on the income level of the household, its current energy consumption patterns (for example, if energy use is saturated, there may not be much room for increasing energy consumption), and other factors. Similar factors will determine the magnitude, if any, of the rebound effect among other electricity consumers such as industry. The rebound effect will not be considered in this version of the guidance note. The rebound effect can be included, however, if the project team concludes that there is enough evidence—from similar interventions in the same consumption sector—for a likely increase in electricity consumption in response to lower total expenditures on electricity (as documented by previous studies or as part of the appraisal with proper statistical sampling of energy consumption outcomes after energy efficiency interventions). Because the rebound effect is unlikely to be zero, not taking it into account over-estimates the net emissions benefit of energy efficiency improvement.

5.5 Computing Gross and Net Emissions

Net emissions are calculated as the difference between project and baseline emissions, as shown in the example in Table 5.1.

Table 5.1: Illustrative net emissions calculation demand side energy efficiency (tCO_2e)

	Baseline	Project	Net
Emissions from changed generation	50	20	-30,0
Total emissions	50	20	**-30,0**

Note: The numbers are for illustrative purposes only.

5.6 Defining the Baseline

The baseline, or alternative or counterfactual to the project intervention, is not the absence of lighting, air-conditioning, refrigeration, and any other use of electricity associated with the appliance or equipment, but rather a project that provides the same level of service for the end user (for example, same lighting service measured in lumens).

The following table provides some guidelines for two potential project interventions in demand-side, energy efficiency improvement that will lead to reductions in the consumption of grid electricity.

Table 5.2: Efficiency intervention and baselines

Project objective	Baseline and project emissions
Replacing incandescent lamps with compact fluorescent lamps (CFLs)	The alternative is to continue using incandescent lamps, the usable life of which is shorter and the energy consumption (to produce the same luminescence) of which is higher—for example, a 20 W CFL in the place of a 100 MW incandescent lamp. The project and baseline scenarios need to consider standard patterns of lamp use in terms of numbers of hour per day. By default, lamps are assumed to be used at least 3.5 hours per day, and they have a total usable life of no more than 8,000 hours (International Electrotechnical Commission standards).
Replacing refrigeration appliances	The alternative is to continue using a less-efficient refrigeration appliance that has more consumption per square foot of cooling volume. A similar procedure should be followed to consider the daily and life energy consumption of the old appliance in the baseline with the new appliance in the project.

While more efficient appliances may already be available in the market and could in fact already be purchased and used by some consumers, what matters in considering less efficient appliances or equipment in the baseline is that the project is actually financing the substitution or purchase of more efficient equipment.

5.7 Net Emissions

The net reduction in emissions is computed as follows:

Net emissions reduction = loss factor (LF) x grid emissions factor x (energy consumption without the project – energy consumption with the project),

where LF is a multiplier greater than 1 and includes the technical losses in the grid up to the point where the more efficient appliance or equipment is installed. For instance, if technical T&D losses in a system total 16 percent, the LF is 1.16. If the intervention is in the industrial sector, which most likely will be connected at the transmission level, the LF captures only transmission losses and would be smaller.

Information on technical losses should be available for the specific grid in question. In the absence of loss information, the following default values should be used:

a) LF = 1.05 for any industrial or other interventions that extract electricity from the grid at the transmission level.
b) LF = 1.10 for any mid-industry, large commercial, or other interventions that may extract electricity from the grid at the sub-transmission level.
c) LF = 1.15 for any intervention at the distribution level.

These factors are on the high side to make the emission reduction estimates conservative.

As mentioned earlier, the energy consumption savings estimated for the project need to capture any documented (for example, standard) degrading factor over the economic life of the appliances/equipment and any properly documented leakage corrections if the project does not have a designed procedure to ensure that the old equipment will not be used any longer (for example, destroying old appliances).

By default, to ensure conservativeness and ease of implementation of the calculation, the average grid emission factor should be used for the grid emission factor, unless the teams have used an alternative, more detailed method to determine the grid emission factor for the particular intervention. For example, the teams may have used more detailed approaches, such as dispatch-based simulation or others consistent with globally accepted approaches to determine grid emissions, such as CDM tools.[34]

[34] CDM Methodological Tool to calculate the emission factor for an electricity system. http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-07-v3.0.0.pdf.

Annex 5A: Examples

Important Note: These examples are for illustrative purposes only. They are not intended to reflect the actual emissions as calculated by teams, since this project was appraised before the corporate requirement. Assumptions will be made for the illustrative purposes of showing the application of the guidance note and to complement information that may not have been available in PADs, but that may have been available to teams in additional project documents such as feasibility studies. Assumptions that are made are for the purposes of illustrating the application of the guidance note and may be different from the prevailing conditions and information available at the time of appraisal.

Example 5A.1: Energy-Efficient Lighting

Name:	MX Efficient Lighting and Appliances
Country:	Mexico
Installed lightbulbs:	45,000,000
Expected savings:	3,047 GWh/year
Economic life span:	3 years

This is a large investment in refurbishing and replacing lighting and appliance infrastructure in Mexico in order to achieve energy-efficiency gains. The PAD states that the project will involve the purchase and distribution of about 45 million CFLs and the collection and proper disposal of the replaced bulbs. These CFLs are assigned a predicted energy-efficiency improvement of 53 watts per bulb and a life span of 3 years.

Calculation of Energy Savings and Net Emissions

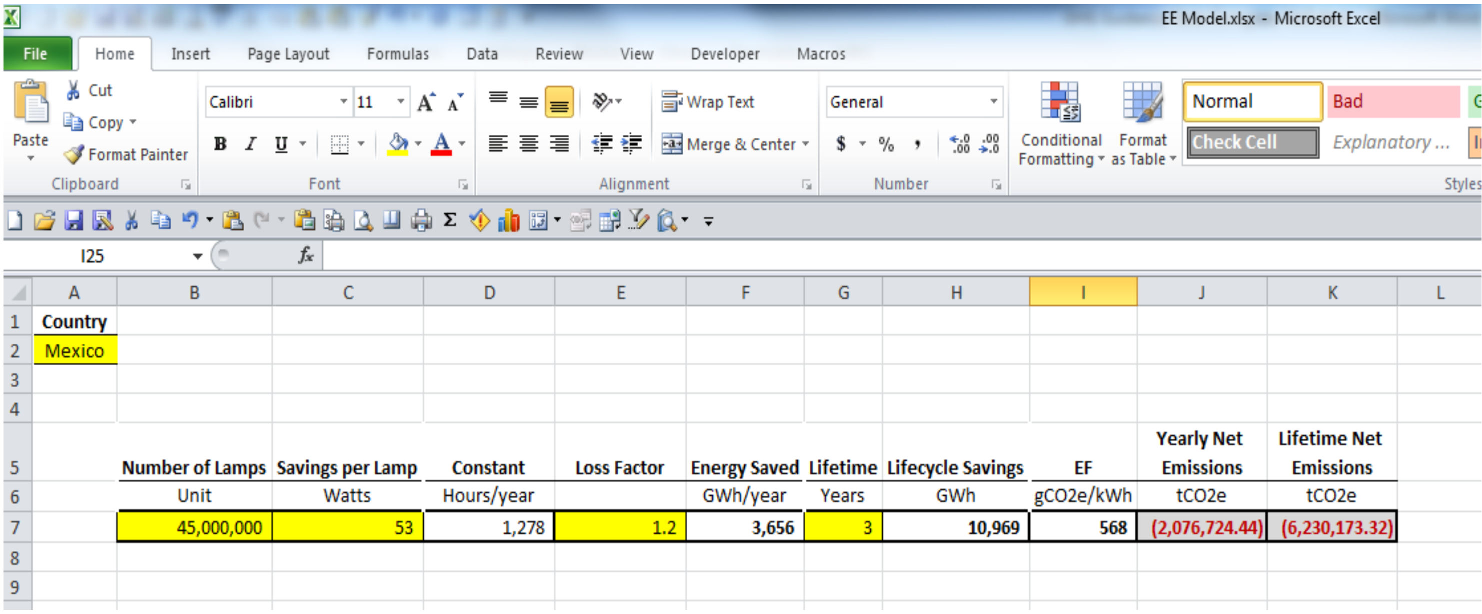
Assuming the standard 3.5 hours usage per day for the CFLs and a loss factor of 1.2, on account of this intervention being at the distribution level, the total energy saved by replacing these bulbs will be 3,656 GWh/year, yielding a total of 10,969 GWh saved at the point of electricity generation over the life of the project.

Mexico grid emission factor = 586 gCO_2e/kWh

⇨ **NET EMISSIONS = 10,969 × 586 = -6.23 million tCO_2e**

The inputs and results for these calculations are summarized in Figure 5.1.

Figure 5.1: Illustrative calculation using Excel



Number of Lamps	Savings per Lamp	Constant	Loss Factor	Energy Saved	Lifetime	Lifecycle Savings	EF	Yearly Net Emissions	Lifetime Net Emissions
Unit	Watts	Hours/year		GWh/year	Years	GWh	gCO2e/kWh	tCO2e	tCO2e
45,000,000	53	1,278	1.2	3,656	3	10,969	568	(2,076,724.44)	(6,230,173.32)