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Impacts of Transmission and Distribution Projects on Greenhouse Gas Emissions

Review of Methodologies and a Proposed Approach in the Context of World Bank Lending Operations

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THE WORLD BANK
The Energy and Mining Sector Board

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Foreword

The Strategic Framework for Development and Climate Change serves to guide and support the operational response of the World Bank Group (WBG) to new development challenges posed by global climate change. Under the framework, the WBG committed to developing and testing greenhouse gas (GHG) emissions accounting methods at the project level to improve the Bank's and its clients' knowledge base, capacity, and access to additional climate finance.

The energy sector is an important source of emissions globally. The WBG has surpassed its commitment to support renewable energy and energy efficiency activities, which will directly contribute to lower-carbon energy sector development. A considerable portion of the Bank portfolio supports transmission and distribution (T&D) infrastructure, which is fundamental to increasing and expanding access to modern energy services.

This report aims to contribute to an understanding of the GHG implications of T&D projects. The report presents a methodological approach that can be used in the context of WBG T&D lending operations to determine the most important impacts of T&D projects on GHG emissions in the power sector.

In addition to helping our staff involved in T&D operations determine these impacts, we hope that our report will contribute to the ongoing debate on developing comprehensive and effective sector-based methodologies for GHG emissions accounting.

We would like to take this opportunity to thank Jamal Saghir. This work was conducted under his leadership during his tenure as director of the former Energy, Transport, and Water Department.

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November 2010

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Abbreviations

AC	alternating current
AM	approved methodology
AMS	approved methodology, small-scale
CDM	Clean Development Mechanism
CEET	Carbon Emissions Estimator Tool
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DC	direct current
FSR	feasibility study report
FY	fiscal year
g	gram
GEF	Global Environment Facility
GHG	greenhouse gas
gWh	Gigawatt hour
ha	hectare
IFC	International Finance Corporation
IGES	Institute for Global Environmental Strategies
IPCC	Intergovernmental Panel on Climate Change
kg	kilogram
km	kilometer
kt	kilotonne
$ktCO_2$	kilotonnes carbon dioxide
kV	kilovolt
kW	kilowatt
kWh	kilowatt hour
m	meter
$MtCO_2$	million tonnes carbon dioxide
MVA	mega volt amperes
MW	megawatt
MWh	megawatt hour
N_2O	nitrous oxide
NM	new methodology proposal
SF_6	sulfur hexafluoride
SFDCC	Strategic Framework for Development and Climate Change
t	ton
T&D	transmission and distribution
tCO_2	tonne carbon dioxide
tCO_2e	tonne carbon dioxide equivalent
WBG	World Bank Group

All dollar amounts cited are U.S. dollars.

Executive Summary

The Strategic Framework for Development and Climate Change (SFDCC) approved in 2008 guides and supports the operational response of the World Bank Group (WBG) to new development challenges posed by climate change. One activity pursued by the SFDCC is to further develop and test methods to analyze climate risks and greenhouse gas (GHG) emissions at the project level. The SFDCC emphasizes the need to improve GHG accounting activities at the project level to understand the implications of the World Bank's interventions.

The SFDCC established that GHG accounting activities should be carried out as an analytical exercise and not as a business requirement of the project preparation or approval process. The framework prescribes a net emissions approach, which computes emissions reductions or increases by comparing emissions in a "without project" scenario and a "with project" scenario. Additionally, GHG accounting activities should be seen by all stakeholders as credible, transparent, feasible, harmonized, and demand driven.

Importance of Transmission and Distribution in the World Bank Portfolio and Power Sector Emissions

The power sector is one of the largest sources of GHG emissions, accounting for more than a quarter of global GHG emissions. Emissions from the power sector have grown dramatically in recent decades, particularly in developing countries. Most GHG emissions accounting analysis for the power sector has focused on emissions from the combustion of fossil fuels in power plants rather than the emissions from the transmission and distribution (T&D) sector. The focus is understandable, given the large share of international investment going into the power generation subsector, and because the majority of emissions from the power sector are a result of the operation of power plants.

However, focusing on direct emissions from the different subsectors within the power sector underestimates the impact of T&D investments on GHG emissions. One reason for this is that anywhere from 7 to 20 percent or more of the electricity generated is lost through technical line losses in the T&D system. T&D losses vary considerably by country, ranging from 7 to 8 percent in North America and Europe to 15 percent or more in Central and South America. In response to demand from developing countries, World Bank financing for energy infrastructure development has increased significantly in recent years, reaching $8.2 billion in fiscal 2009. T&D accounts for $6.1 billion, or 22 percent, of all energy sector lending in the past seven years.

Study Objective

The objective of this study is to contribute to the SFDCC goal of improving GHG accounting in the energy sector by reviewing, assessing, and recommending GHG accounting methodologies for electricity T&D projects. Existing methodologies are examined to test whether they can provide simple and accurate estimates of net project emissions. In addition, the study identifies and conceptually designs a methodological approach for T&D projects. The study focuses on the T&D sector due to its importance in the World Bank's energy lending portfolio and the lack of comprehensive methodologies to determine the impact of such interventions on GHG emissions. The study builds on existing information and relies on methodologies developed under different climate finance mechanisms such as the Clean Development Mechanism (CDM).

The study also considers some of the fundamental principles in other accounting procedures, such as corporate GHG accounting. Methodologies that have the objective of emissions accounting for climate finance mechanisms need to have specific characteristics, such as additionality and ex post monitoring. These methodologies must calculate a project's emissions reductions or increases by estimating the project's net emissions impact. Most corporate GHG accounting methodologies estimate and report a corporation's emissions inventory, similar to how the Intergovernmental Panel on Climate Change (IPCC) methodologies are used for national GHG inventories. These methodologies do not require additionality tests. The study investigates elements of both emissions accounting approaches due to the increasing need to understand the carbon intensity of the World Bank portfolio and to fulfill the SFDCC's objective of performing accounting at the project level using a net emissions approach. The study aims to identify methodologies that can provide simple, rapid, and accurate estimates of net emissions impacts in the context of the project preparation cycle.

Diversity of T&D Projects and Associated GHG Impacts

World Bank T&D project interventions are very different from traditional private sector or CDM transactions. T&D projects are quite diverse in terms of the technologies supported, the objectives being pursued, and the scope of the intervention in the context of larger utility investment plans and multidonor financing. These challenges make analyzing the GHG impacts of World Bank projects difficult. The proposed approach is modular in order to accommodate the diversity of projects and to recognize the different mechanisms by which T&D investments can affect emissions from power generation plants. In some cases, these modules are simpler than similar CDM baseline methodologies. There are several reasons for this. First, the objective of this study is to provide methodologies that can be used ex ante to estimate GHG impacts. Consequently, they do not include a monitoring methodology. Second, the methodologies must rely on data traditionally collected during project preparation and appraisal, which generally do not provide the level of detail a dedicated carbon finance feasibility study would require. Third, the GHG emissions impact assessment is not used for generating credits or securing carbon revenue. Therefore, the level of accuracy required is not as stringent as for carbon finance projects.

Review of GHG Accounting Methodologies

The survey of methodologies and case studies indicates that direct nongeneration emissions for T&D projects are well covered by many existing approaches. There is broad consensus on the type of emissions that are relevant and their estimation methodology. Estimating these impacts requires additional data beyond that typically available during project preparation and appraisal.

There is less experience in the analysis of the impacts of T&D projects on emissions from power generation in terms of net emissions impacts. Several potential impacts have no accepted estimation methodologies at all. The direct impact on power generation of technical loss reduction and the indirect impact on generation of electrification are noted in several methodology guidelines and international studies. However, the impacts of T&D projects that seek to increase reliability or capacity have not been analyzed for their GHG contributions. Cross-border trade, although raised by several proposed CDM methodologies, does not have an accepted standard for GHG impact analysis.

Significance of Net Emissions Approach

One of the most important conclusions of this work is that the impacts of T&D projects on generation emissions are likely to be much higher than those on direct nongeneration emissions. In some cases, the net emissions impacts could be negative (that is, the project would contribute to reducing overall system emissions), even though direct nongeneration emissions are positive. As a result, assessing the impacts on power generation may be even more important than calculating direct nongeneration emissions of T&D projects. Leaving out the impact on generation emissions in the GHG analysis could significantly underestimate the impact of T&D projects on GHG emissions.

Summary of Approach

The proposed approach links T&D project objectives to their potential impacts on GHG emissions. This approach facilitates rolling out GHG accounting in the context of current practices for technical and economic evaluation of World Bank projects. Different modules to assess GHG impacts are proposed for different objectives. The approach also facilitates the analysis of a variety of project objectives by type and the identification of different mechanisms by which the intervention can affect emissions from power generation.

Three categories of emissions impacts from GHG projects are delineated, as shown in table E.1. In these definitions, the physical boundary of the T&D project (as opposed to the boundary in terms of emissions sources) consists of the physical site(s) where the project will be constructed. Examples would be substations, transmission lines, and the right-of-way corridor for a transmission expansion project.

Actions outside the physical boundary of the project could include investment in power generation and changes in dispatch or in the operation of nongrid generators or energy sources. Since indirect impacts will occur only if these other actions take place, these emissions are not fully attributable to the project, although the project *contributes* to these emissions reductions or increases. Direct emissions can be attributed to the project. All impacts are analyzed over the same project life that is used in the technical and economic analysis performed during the Bank's project appraisal.

Table E.1: Categories of T&D Project Impacts on GHG Emissions Used in This Study

Category of emissions impact	Description
Direct nongeneration effects	Similar to standard corporate or national inventory. Emissions that occur within the physical boundary of the T&D project, and possibly through the life cycle of that equipment.
Direct generation effects	Effect on short-term and/or long-term generation emissions that does not require any other actions outside the physical boundary of the T&D project. This would be the case for technical loss reduction projects.
Indirect generation effects	Effect on short-term and/or long-term generation emissions that requires actions outside the physical boundary of the T&D project. This would be the case for increased reliability, capacity expansion, electrification, and cross-border trade.

Source: Authors' analysis.

Categories of Emissions Impacts

Emissions impacts caused by T&D projects can be categorized based on the location of the emission-altering activity in relation to the defined boundary of the T&D project, and by the location of the activity with respect to the physical site of power generation.

Direct Nongeneration Emissions

GHG emissions resulting from operations within the project boundary, but emitted as a result of activities occurring outside the physical site of power generation, are classified as direct nongeneration emissions. These emissions include the following:

- Embodied emissions from construction materials.
- Energy use in construction.
- Land clearing emissions.
- Sulfur hexafluoride (SF6) fugitive emissions.

Embodied emissions from construction materials: This source set is included where there are sufficient project data on construction materials required and their origin. This is likely to be a small emissions source, and generally, projects at early stages of development will not have a detailed inventory of the materials required.

Energy use in construction: This source set is included only where there are sufficient project data on fuel usage in the construction phase. This is likely to be a small emissions source, and not all projects will have a detailed estimation of the equipment fuel usage during construction.

Land clearing emissions: Land clearing could be a significant source of emissions, depending on the vegetation type. The area to be cleared and the carbon density of the biomass to be cleared should be available in the feasibility studies or can be estimated during project preparation.

Sulfur hexafluoride (SF_6) fugitive emissions: These emissions are generally small, but could be significant for projects that install high-voltage equipment. The calculations are preferably based on the SF6 capacity of the new equipment installed. Where these data are not available, default values for high- or medium-voltage system components may be used. If projects do not install any new equipment, this emissions source should not be included, because the SF6 emissions from existing equipment would have occurred even without the project.

Generation Emissions Impacts

The project boundary for generation emissions impacts is the physical site of the power generation plants connected to the grid, as well as captive or off-grid power generation plants that may be displaced as a result of the T&D project. Upstream impacts on fuel extraction or transportation are not taken into account, nor are downstream impacts in electricity consumption.

To assess the net impact on power generation, different modules for baseline and project emissions are applied to the projects according to the multiple objectives and characteristics of the projects. A series of decision trees identifies the modules to be applied. A given project might have several objectives or impacts. In this case, each module would be applied separately to the project. For example, an electrification project might have land clearing, SF6-containing equipment installation, and displacement of an identified minigrid or isolated generators. The baseline for each power generation impact and project type is described below.

Direct Generation Effects

Actions that result in an increase or decrease in emissions within the T&D project boundary and occur at the physical site for power generation are classified as direct generation effects. This includes technical loss reduction.

Technical loss reduction: The baseline is the quantity of electricity lost through technical losses prior to the project. Baseline emissions are the product of historical electricity losses and the marginal emission factor of the grid. Project emissions are electricity losses after implementation of the project multiplied by the marginal emission factor of the grid. If a detailed load flow and power generation model are available, these projections are used instead to assess the generation emissions impact.

Indirect Generation Effects

Actions that result an increase or decrease in emissions partially due to the T&D project but outside the project boundary, and occur at the physical site for power generation are classified as indirect generation effects. These include the following:

- Increased reliability.
- T&D capacity expansion.
- Electrification.
- Cross-border trade.

Increased reliability: Where the project technical and economic analysis specifies what power source would have been used when grid power was not available, baseline emissions are the product of the emission factor of this source and the increased power delivered (once reliability improves). If no alternative source of power is identified in the project documents, baseline emissions are zero. Project emissions are the increased grid power generation multiplied by the marginal emission factor of the grid.

T&D capacity expansion: Where the project technical and economic analysis specifies what power source would have been used if grid power were not supplied, baseline emissions are the product of the emission factor of this source and the quantity of electricity supplied by the new T&D capacity. In other cases, where an alternative is not specified, baseline emissions are zero because there would have been no power supply without the capacity expansion. Project emissions are the quantity of electricity supplied by the new system multiplied by the marginal grid emission factor. For cases where a single new plant supplies the incremental power, that plant's emission factor is used. If a transmission line connects two previously separate grids, the cross-border trade module is applied instead of the capacity expansion module.

Electrification: The baseline is the alternative sources of power for the customers who will be connected to the grid, as identified in the technical and economic analysis of the project. As with capacity expansion and increased reliability, if no alternative sources are identified in the technical and economic analysis, the baseline is zero emissions. Baseline emissions are the product of the increased supply of electricity multiplied by the emission factor of the alternative power source. Project emissions are the increased supply of electricity multiplied by the marginal grid emission factor, adjusted for incremental technical losses where necessary. For cases where a single new plant supplies the incremental power, the plant's emission factor is used. The major limitation in this case is the lack of an accounting approach for the displacement of nonelectric energy sources. This is an area that has not been addressed by existing methodologies and is beyond the scope of this report. The World Bank has recently commissioned a major study on a CDM baseline methodology for rural electrification that will explore the quantification of these impacts.

Cross-border trade: Baseline emissions are the product of the incremental traded electricity measured at the receiving substation and the marginal grid emission factor for the importing country. Project emissions are the product of the incremental traded electricity measured at the receiving substation and the marginal grid emission factor for the exporting country, adjusted for losses on the new line. For cases where a single new plant supplies the incremental exported electricity, the plant's emission factor is used for project emissions. If a detailed load flow and power generation model is available for both grids, these projections are used to assess the emissions impact of the project.

Findings of the Pilot Exercise

The proposed approach was piloted to estimate the GHG impacts of the T&D interventions included in three World Bank loans at different stages of preparation. These projects comprised a proposed transmission interconnection between Ethiopia and Kenya; a distribution loss reduction project in Brazil; and a power generation, transmission, and distribution access scale-up program in Kenya. Despite the small sample, the projects reflect to a great extent the variety of project types supported by the Bank.

The three cases explored indicate that direct nongeneration emissions are relatively small compared to the direct and indirect impacts on power generation. This is supported by evidence from the study literature review. In all cases, direct nongeneration emissions range from 0 to 6 percent of generation impacts. For example, the direct nongeneration emissions for the interconnection between Ethiopia and Kenya are estimated at +804 kt of carbon dioxide (CO_2), largely from land clearing, while the indirect impact on power generation is estimated at −69,812 ktCO_2 because of the displacement of power from a higher emissions grid. For one of the transmission projects in Kenya, direct nongeneration emissions are estimated at +14 ktCO_2, while the direct generation impact is −38 ktCO_2 and the indirect generation impact is +392 ktCO_2. The T&D rehabilitation project in Brazil results in a direct generation impact of −571 ktCO_2 and an indirect generation impact of −145 ktCO_2, and it has negligible nongeneration emissions.

These examples show that T&D interventions contribute to reduced emissions, especially when systems are interconnected to make better use of power generation sources when reliability is improved or technical losses are reduced. Thus, achieving the development objectives of T&D projects can also lead to emissions reductions. Projects may also contribute to increased emissions, especially when they increase T&D capacity to serve increased demand growth that will otherwise not be served by other energy sources.

While current project preparation procedures already provide most of the data that are crucial in net impacts estimation, collection of data will require improvements over time, especially for the direct nongeneration emissions modules. For instance, although embodied emissions from material construction are known to be small as supported by the pilot projects, not all projects will be able to determine these emissions during project preparation, since the amount of material required and their respective manufacturing sites are often not known until the project implementation phase. Some of the issues concerning data availability are discussed further below.

Data, Baselines, and Uncertainty

For **direct nongeneration emissions accounting**, the quantity of construction materials required for different projects is not usually known with certainty at the project preparation time because the detailed feasibility studies have not been completed. The relatively small size of this impact would not merit additional effort by the project teams. While land clearing is generally covered in the environmental and social impact assessments, the project documentation should clarify the IPCC-defined vegetation types so the correct emission factor can be used. A lack of detailed data on equipment containing SF_6 is a gap that must be addressed, particularly for projects that include high-voltage equipment. Existing environmental and social safeguards require regulated handling of SF_6, but there is no requirement to quantify the fugitive emissions or specify the characteristics of all equipment being installed.

There will be uncertainty in estimating the direct nongeneration GHG impacts of the project, but these impacts are generally small compared to generation emissions impacts. The default factors in the proposed approach may lead to overestimation of emissions (for example, SF_6 national default factors or high carbon density values for land cleared in case of vegetation type uncertainty would overestimate emissions). Erring on the high side for these relatively small sources is preferable to underestimating them, but the best solution is to collect the data during project preparation.

There are some data requirements for estimating the **impact on generation emissions** that teams preparing projects need to understand. Although grid emission factors from the Institute for Global Environmental Strategies CDM database or a registered CDM project can be used, project teams could consider collecting primary data during project preparation. Large high-voltage interconnection projects that conduct a power generation simulation for their economic analysis will already have this information. However, lower-voltage distribution and electrification projects will generally not perform such an analysis and, as a result, grid emission factors will need to be estimated.

One important challenge in assessing net impacts of increased reliability, technical loss reduction, and capacity expansion projects is the clear separation of the impacts of these objectives both theoretically and practically. While load flow and long-term economic dispatch simulations could provide reliable information to supply all the modules, such simulations are not carried out for all types of projects. If the impacts on losses and reliability are determined separately, it is essential that the teams use consistent baselines and project scenarios. For instance, if the impact on the project's technical losses is estimated for an entire network, the impact of the project on increased transmission capacity should also be analyzed for the entire network.

For capacity expansion projects—and, to a lesser extent, for electrification projects—a source of uncertainty is how the baseline captures alternatives to the grid. In other words, if a capacity expansion project were not implemented, would the customers find other sources of an equivalent amount of power? This is both a question of principle and of practice. The *principle* issue is that economic development will drive the need for more power that must be provided by the grid or other sources. Even if those alternatives are not currently in place, to exclude them from the baseline would be, in essence, to assume that demand for power is not growing. At the same time, the reality is that the lack of power is a major constraint to development, and many large industrial projects would not be implemented without significant T&D capacity expansion. The *practical* issue is whether the project team can provide projections that identify the demand that would not be satisfied if a capacity expansion project was not implemented—that is, suppressed demand. This uncertainty is not particular to the proposed approach, but is true for any type of technical and economic assessment of projects and for other accounting methods. The present proposal is a practical compromise—that is, to use the emissions of the alternative power sources identified by the project team while performing the technical and economic appraisal of the projects as the baseline emissions, and to use a zero emissions baseline where there is no alternative source identified. Although the latter case will result in higher emissions estimates, it is preferable since impacts will be estimated on the conservative side.

Estimating emissions impacts is straightforward for cross-border trade projects when load flow and long-term dispatch modeling data exist. This is likely to be true for some large high-voltage interconnection projects, but certainly not all (for example, smaller-scale projects that interconnect small distribution zones). In these latter cases, the challenge lies in deciding whether the marginal emission factors for the grid accurately represent the impacts on dispatch caused by the project.

The main challenge in electrification lies in the identification of a method to address the displacement of fuels other than electricity. The approach presented in this report considers only the displacement of other electricity sources. A separate work by the World Bank is looking at this topic. It aims to review the literature on rural electrification to determine whether there are consistent patterns of baseline energy use and shifts in post-electrification patterns across different countries and regions. This will be the first such effort to address fuel displacement in the context of carbon financing or carbon accounting.

Lessons Learned and the Way Forward

Understanding the GHG emissions implications of World Bank interventions supports the process of identifying lower-carbon options, facilitates the use of emerging clean technology and climate funds, and increases the capacity of World Bank staff and clients. With this in mind, the proposed approach has been designed to suit the structure of World Bank projects in order to facilitate its implementation in the context of existing project preparation practices, while capturing most relevant impacts on GHG emissions from T&D interventions.

The proposed approach would not impose a significant additional burden on project preparation, and it could be applied to projects if a specific mandate or incentives—such as climate financing—are introduced.[1] The latter has generated interest from some of the clients whose projects were considered in the pilot process. While the proposed methodology is ready to be deployed for T&D projects in the context of current project preparation practices, it must be emphasized that the activities concerning methodology development for GHG accounting and testing are, as described by the SFDCC and endorsed by the board, an analytical exercise. The formal adoption of GHG accounting procedures for Bank operations may require some uniformity and consistency across all sectors. As the work on piloting GHG accounting in other sectors moves forward, a Bank-wide proposal on GHG analysis would be proposed to the Board as envisaged by the SFDCC.

Besides contributing to the SFDCC objectives, this work contributes to the ongoing debate on methodology development that seeks a more comprehensive, easy-to-use, and reliable sector- and subsector-based GHG accounting process across multilateral development banks. Moving away from the complexities and associated costs of project-based accounting methodologies is an approach also being seriously considered for a reformulated CDM.

[1] For a typical project with two components, performing GHG accounting with the proposed approach should require about 10 days of work in coordination with the team members performing the project's technical and economic evaluation.

1. Introduction

The Strategic Framework for Development and Climate Change (SFDCC) approved in 2008 guides and supports the operational response of the WBG to new development challenges posed by climate change. Different initiatives are supported by the strategic framework. One of these activities is the improvement of the knowledge and capacity of WBG staff and clients to analyze development-climate links at the global, regional, country, sector, and project levels. Further development and testing of methods to analyze climate risks and greenhouse gas (GHG) emissions at the project level is critical to achieving this objective. Specifically, the strategic framework (World Bank 2008a) mentions the following:

> …the WBG is developing methods to analyze climate risks and GHG emissions at the project level in GEF [Global Environment Facility] and carbon finance projects. Their application will extend, for learning and information purposes, to a larger pool of projects. The Bank will select pilot projects on a demand basis, and will work in close cooperation with clients and local institutions. The IFC [International Finance Corporation] will progressively apply these tools to its projects to inform the dialogue with its private sector clients on climate related business opportunities and risks. This is an analytical exercise. It is neither a business requirement, nor it will [sic] be used for decision-making about projects using traditional WBG financing instruments. By the end of the piloting period, a proposal will be prepared for Board consideration on the future applications of the tools for GHG analysis appropriate for Bank and IFC business models, client needs, and available climate financing instruments.

The strategic framework sets out important principles that will guide the development and testing of methods for GHG emissions analysis. It emphasizes the need for GHG accounting activities to follow a net emissions approach, discussed in more detail below, which computes emissions reductions or increases by comparing emissions in a "without project" scenario and a "with project" scenario.[1] Additionally, GHG accounting activities should be seen by all stakeholders as **credible**, **transparent**, **feasible**, **harmonized**, and **demand driven**. The purpose of the activities is to

- build staff and client capacity for carbon analysis to prepare for a carbon-constrained future;
- gather information to understand better the implications of possible new approaches;
- identify low-cost mitigation opportunities across operations, especially in sectors that may be currently overlooked, that is, beyond energy and transport;
- facilitate an analysis of alternatives; and
- help promote the efficient use of emerging climate funds, including the Clean Technology Fund.[2]

[1] "…An emerging approach in all…sectors is to undertake GHG assessment, focusing on net emissions from a project, as part of a broader analysis of all project benefits and external costs, including a range of externalities…. This would allow the analysts to place the GHG analysis of a project in the context of its development impact and assess the trade-offs where applicable" (World Bank 2008a, p. 72).

[2] World Bank (2008a), p. 73.

Importance of T&D in the World Bank Energy Portfolio

In response to demand from developing countries, WBG financing for energy infrastructure development has increased significantly in recent years, reaching $8.2 billion in fiscal 2009 (see table 1.1).[3] Energy infrastructure projects seek to increase energy access; develop renewable energy and energy efficiency; and leverage private sector participation in energy generation, transmission, and distribution, including through effective public-private partnership arrangements.

[3] Sourced from http://go.worldbank.org/ERF9QNT660.

In the lending portfolio for the last seven years, transmission and distribution (T&D) projects comprise $6.1 billion, or more than 22 percent of all energy sector lending (see table 1.2 and figure 1.1). According to the formal classification for World Bank lending, T&D projects are associated with new network capacity expansion or rehabilitation of existing T&D systems. These are projects that have new T&D equipment associated with network capacity expansion. T&D rehabilitation projects, even if they implicitly result in loss reduction, are included in this category if the energy efficiency component cannot be clearly disaggregated from network expansion or load increase. If the financing for energy efficiency components of T&D rehabilita-

Table 1.1: WBG Energy Portfolio by Financing Source, FY2003–09 ($ millions)

Institution	FY2003	FY2004	FY2005	FY2006	FY2007	FY2008	FY2009
World Bank	1,176	921	1,868	3,155	2,016	4,512	6,548
IBRD[a]	468	259	593	1,565	504	2,674	3,569
IDA[a]	560	535	712	1,441	1,070	1,420	2,155
GEF[b]	55	62	105	51	128	145	84
Other[c]	93	64	458	98	314	272	740
IFC[d]	638	705	764	1,308	1,170	2,923	1,647
MIGA[e]	556	73	232	190	417	110	33
WBG energy total	**2,370**	**1,699**	**2,864**	**4,653**	**3,604**	**7,545**	**8,228**

Source: World Bank calculations.

a The International Bank for Reconstruction and Development (IBRD) and the International Development Association (IDA) together make up the World Bank.

b The Global Environment Facility (GEF) provides grants and concessional loans to help developing countries meet the costs of measures designed to achieve global environmental benefits. The World Bank is one of the three implementing agencies of the GEF.

c *Other* includes guarantees, carbon finance, special financing, and recipient-executed activities. Concerning carbon finance, the World Bank Carbon Finance Unit uses funding contributed by governments and companies in Organisation for Economic Co-operation and Development (OECD) countries to purchase project-based GHG emissions reductions in developing countries and countries with economies in transition. Clean Technology Fund financing is not included in FY2009 financing figures.

d The International Finance Corporation (IFC) provides loans, equity, and technical assistance to stimulate private sector investment in developing countries.

e The Multilateral Investment Guarantee Agency (MIGA) provides guarantees against losses caused by noncommercial risks to investors in developing countries.

Table 1.2: Sectoral Breakdown of WBG Energy Lending, FY2003–09 ($ millions)

Sector	FY2003	FY2004	FY2005	FY2006	FY2007	FY2008	FY2009
Energy efficiency	177	92	217	761	262	1,192	1,701
Large hydropower[a]	23	83	538	250	751	1,007	177
New renewable energy[b]	206	138	246	344	421	473	1,427
Oil, gas, and coal (upstream)	333	496	578	1,074	627	981	1,032
Other energy[c]	816	370	278	248	375	903	1,752
Thermal generation[d]	599	272	100	511	360	957	936
T&D	216	248	906	1,465	809	2,031	1,204
WBG energy total	**2,370**	**1,699**	**2,864**	**4,653**	**3,604**	**7,545**	**8,228**
Total low carbon[e]	406	350	1,237	1,660	1,440	3,003	3,305
Total access[e]	794	537	1,136	1,018	1,239	2,284	2,201

Source: World Bank calculations.

a *Large hydropower* refers to hydropower projects larger than 10 MW.

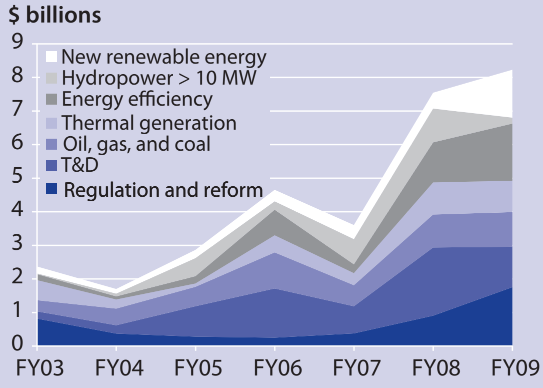
b *New renewable energy* refers to all renewable energy, excluding hydropower projects larger than 10 MW.

c *Other energy* includes energy policy support projects.

d *Thermal generation* includes all new fossil fuel power plants, including high-efficiency fossil fuel power plants (super- and ultra-critical power plants).

e *Low-carbon projects* include renewable energy projects, energy efficiency, power plant rehabilitation, district heating, and biomass waste energy. *Access projects* include projects aimed at increasing access to electricity services. These categories are not mutually exclusive, as some projects are classified as blended low carbon and access. For IDA countries, access includes all generation, transmission, and distribution projects, as they are all needed for increased electrification. For IBRD countries, only projects specifically aimed at increasing electricity access (for example, rural electrification projects) are included.

Figure 1.1: Sectoral Breakdown of WBG Energy Lending, FY2003–09



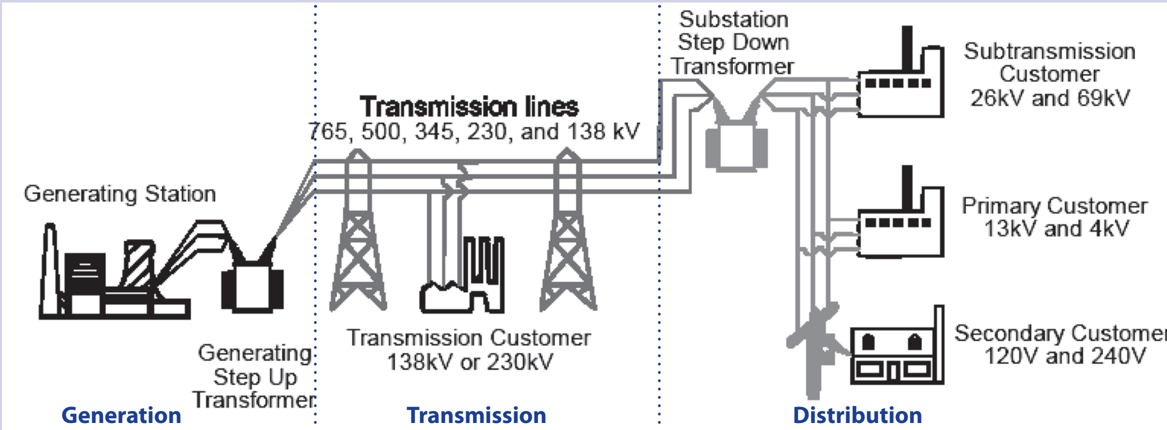
Source: World Bank calculations.

tion projects can be disaggregated, they are classified as supply-side energy efficiency.

Significance of the Electricity Sector in Global GHG Emissions

Electricity grid systems are typically divided into generation, transmission, and distribution (see figure 1.2). While power generation investments can be clearly distinguished in any grid, the boundary between T&D is not always consistent across countries. Different countries use different voltage levels for this distinction. For one country, a line operating at 69 kV could be considered part of the transmission system, while for another country any line at

Figure 1.2: Electricity Grid Components



Source: Brown and Sedano 2004.

69 kV could be considered part of the distribution system. Some classifications state that the transmission system ends at the substation where the voltage is stepped down from 138 kV to less than 100 kV (usually less than 50 kV). There are cases, however, where relatively long-distance lines may operate below 100 kV, or where distribution lines within an urban area could be more than 100 kV. For the purpose of analyzing GHG emissions impacts, the exact boundary between these systems is not as important as how these investments affect generation of power. The boundary between T&D is essentially the transformers that operate one voltage level above those for individual households.

It is also useful to distinguish those transmission investments that seek to interconnect two previously isolated networks (either within a country or between countries) versus those aimed at upgrading and strengthening existing transmission lines. New interconnectors may significantly affect not only the flow of power between countries or subnational regions, but also the dispatch of grid-connected plants, resulting in a change in the mix of power plants supplying the grid at any given time. This can have a major impact on GHG emissions if hydroelectricity displaces coal- or gas-fired power in a thermal power–dominated grid. Upgrades to existing transmission lines, either within a connected grid or across a national boundary, could also have this impact if the increase in capacity is significant enough. However, if they only reduce technical losses, they may not affect the mix of operational generating plants.

The **transmission system** includes lines and substations. Substations may contain transformers, switches, circuit breakers, voltage regulators and capacitors, power factor correction devices, and storage devices. Direct current (DC) transmission systems also include a rectifier to convert generator alternating current (AC) power into DC power, and an inverter to convert the DC power to AC power when it enters the distribution system. The lines would normally be mounted on steel lattice towers because underground lines require cooling and are much more expensive.

The **distribution system** includes all the equipment from the transmission substation to the individual customer's meter. The feeder lines of a distribution system would operate between 2.4 kV and 33 kV. Network equipment would comprise distribution substations, pole-mounted transformers, low-voltage distribution wiring, and sometimes electricity meters. The distribution substations would have transformers, switches, and circuit breakers or fuses.

Emissions from the Power Sector

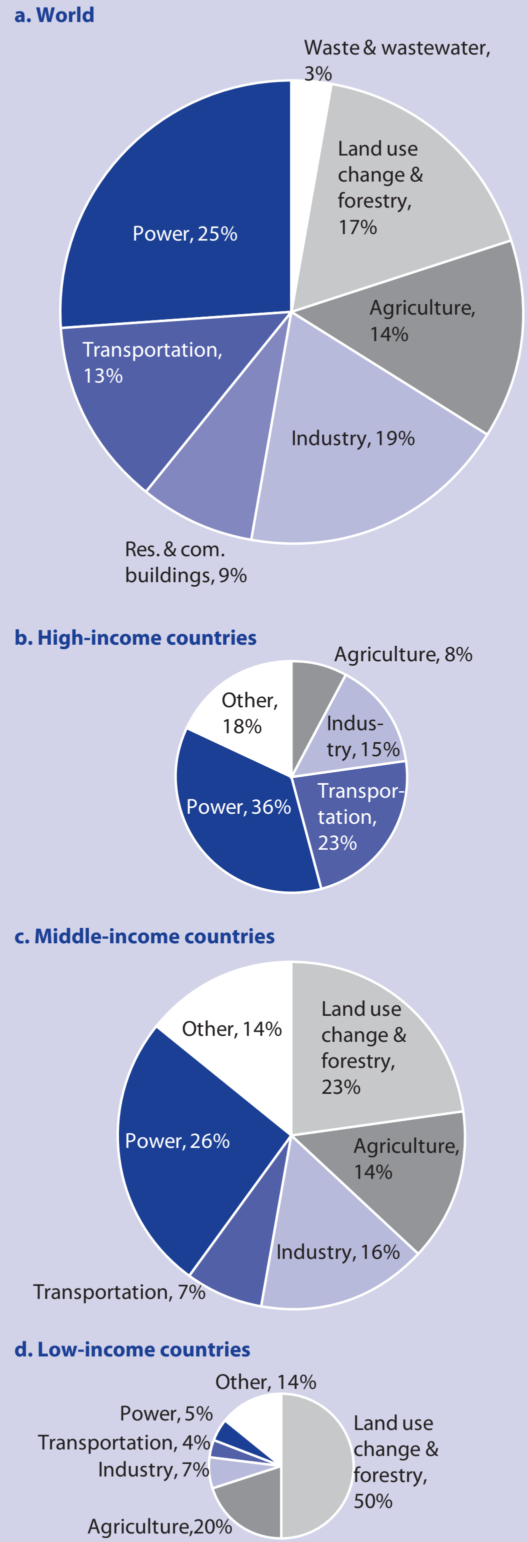
According to the 2010 *World Development Report*:

> Globally, power is the largest single source of greenhouse gas emissions (26 percent), followed by industry (19 percent), transport (13 percent), and buildings (8 percent), with land-use change, agriculture, and waste accounting for the balance.… The picture varies, however, across income groups. High-income country emissions are dominated by power and transport, while land-use change and agriculture are the leading emissions sources in low-income countries. In middle-income countries, power, industry, and land-use change are the largest contributors—but with land-use change emissions concentrated in a handful of countries (Brazil and Indonesia account for half the global land-use change emissions). Power will most likely continue to be the largest source, but emissions are expected to rise faster in transport and industry (World Bank 2010).

This is illustrated in figure 1.3. In addition, emissions from the global power sector have grown dramatically in recent decades, particularly in developing countries (see figure 1.4).

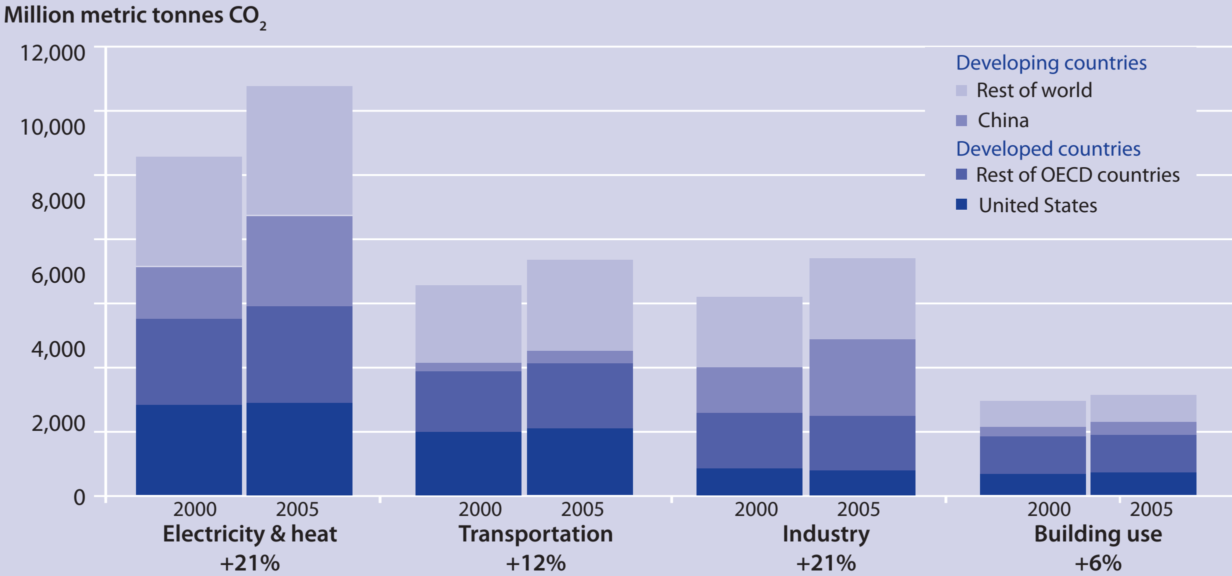
Most of the GHG analysis of the power sector has focused on emissions from combustion of fossil fuels in power plants, rather than issues in T&D (see, for example, Bosi and Laurence 2002; Kartha, Lazarus, and Bosi 2004; Sharma and Shrestha 2006; GHG Protocol 2007). Many of the early CDM methodologies were also related to power generation. The methodologies being developed in the Activities Implemented Jointly trial period for project-based emissions trading under the United Nations Framework Convention on Climate Change also focus on power generation. For this reason, the second consolidated methodology approved by the CDM Executive Board was for grid-connected renewable power projects that displaced grid-connected fossil fuel plants. The focus is understandable, given the large share of international investment going into the power generation subsector, and the fact that most of the emissions from the power sector come from the operation of power plants (see figure 1.5).

Figure 1.3: GHG Emissions for the World by Sector and Country Income Level



Source: World Bank 2010.

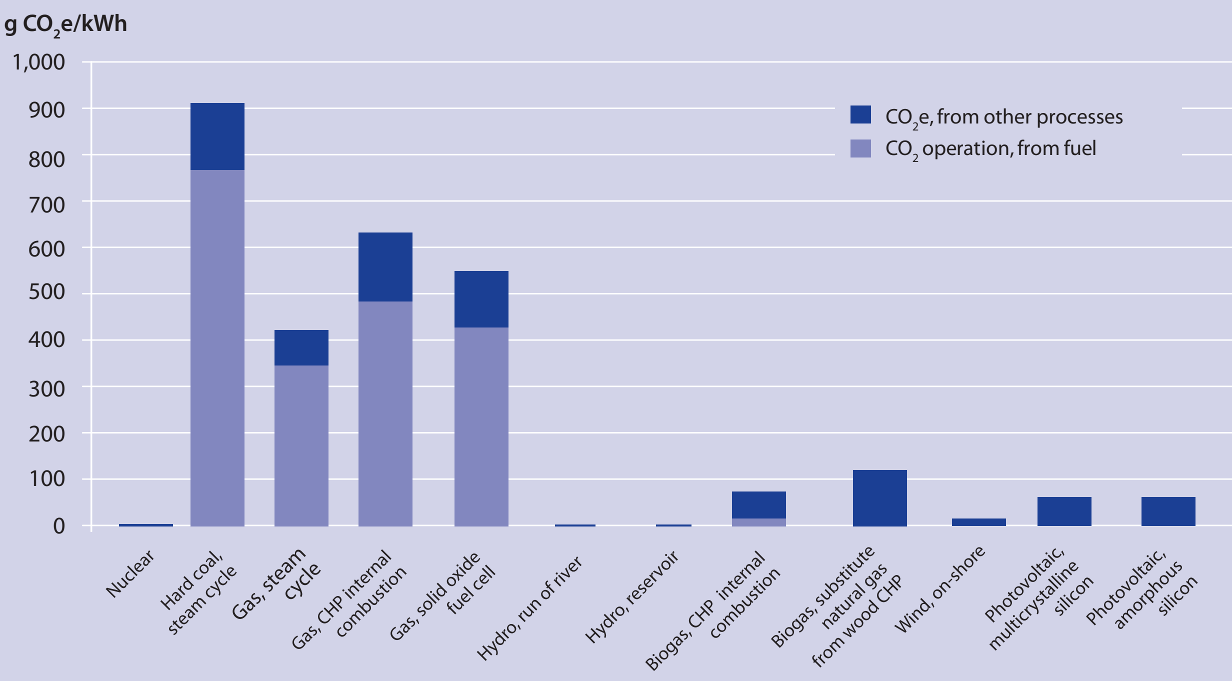
Figure 1.4: Global Growth in Carbon Dioxide Emissions by Sector and Region



Source: Herzog 2009.

Note: OECD = Organisation for Economic Co-operation and Development; CO_2 = carbon dioxide.

Figure 1.5: Life-Cycle GHG Emissions for Electricity by Fuel Type: 2005



Source: Bauer et al. 2008.

Note: Hard coal is for Germany, all others are for Switzerland. CHP = combined heat and power.

Given the focus on power generation, much less analysis of the impacts of T&D investments on GHG emissions has been done, and particularly on how these investments affect the rest of the power sector. The standard guidelines for the power sector (for example, GHG Protocol 2005b; IPCC 2006b) generally say very little about emissions related to T&D, which is part of the rationale for this study.

Focusing on direct emissions from the different subsectors within the power sector underestimates the impact of T&D investments on GHG emissions. One reason for this is that anywhere from 7 percent to more than 20 percent of the electricity generated is lost through technical line losses within the T&D system. Box 1.1 illustrates the importance of T&D investments on emissions with a World Bank analysis of the mitigation options for the Indian energy sector.

T&D losses vary considerably by country. As shown in figure 1.6, losses range from 7 to 8 percent in North America and Europe to more than 15 percent in Central and South America. In developing countries, however, a substantial portion of these losses are "nontechnical" (that is, electricity is consumed, but the utility does not receive revenue because it is not being metered or it is being taken illegally, among other reasons). Figure 1.7 presents an example of this taken from a survey of African utilities.

Considering a major developing country such as India, where technical T&D losses are 29 percent (South Asia Sustainable Development Department 2009) and power sector emissions in 2006 were 744 Mt of carbon dioxide (CO_2) (WRI 2006), these losses amount to 217 $MtCO_2$. In China, where power sector emissions were 3,000 $MtCO_2$ in 2006 (WRI 2006) and technical losses were 18 percent (IEA 2009), these losses would be responsible for 552 $MtCO_2$. This is larger than the total national GHG emissions (2005) from France, South Africa, or Ukraine (WRI 2006).

An additional dimension of the impacts of T&D investments on GHG emissions that has been largely

Box 1.1: Example of the Importance of T&D Investments to Power Sector GHG Emissions Reductions in India

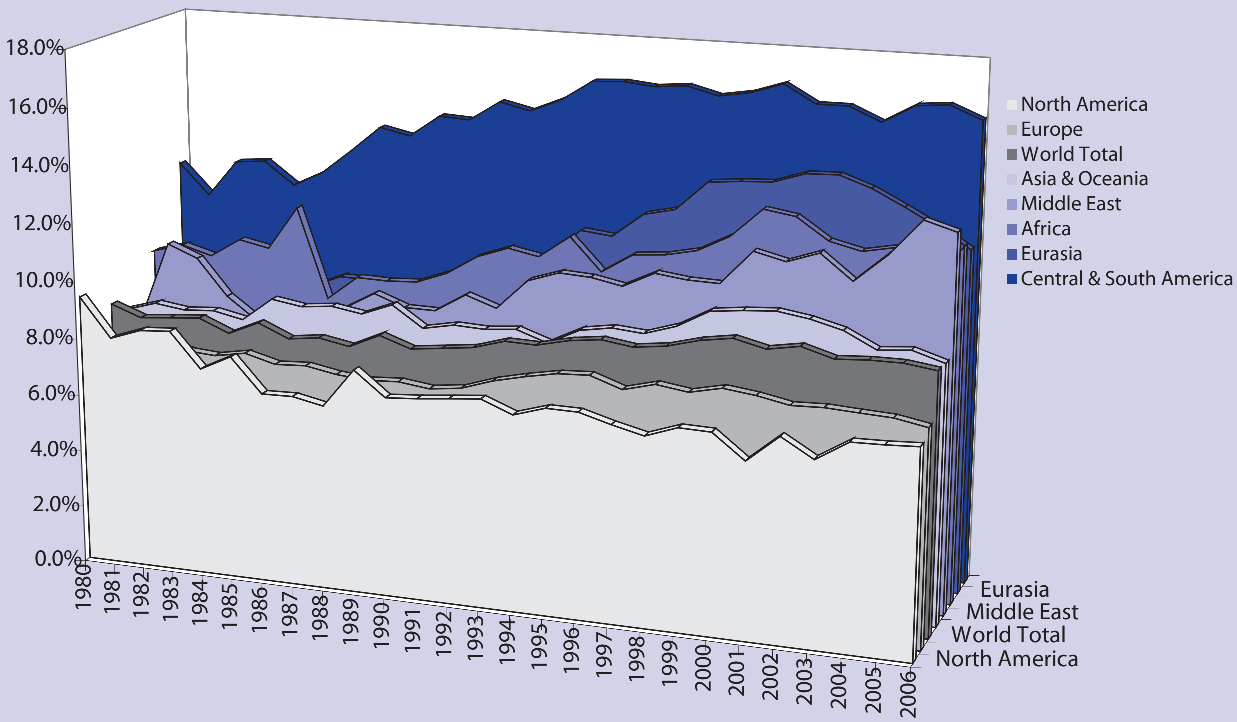
A World Bank analysis of low-carbon options for the Indian economy concludes that "reducing technical T&D losses is one of the most cost-effective means of improving power sector performance while simultaneously reducing CO_2 emissions. Reducing technical losses is in fact equivalent to adding new capacity with no increase in CO_2 emissions." The table below shows the impact of advancing or delaying by five years the implementation of the T&D loss reduction program assumed in the baseline power sector development plan (scenario 1) on CO_2 emissions and total investment over a 25-year period, assuming that the same amount of grid electricity will be supplied to end users in all cases. If the program is accelerated 5 or 10 years, emissions and investment requirements decline significantly.

T&D loss reduction implementation	Change in CO_2 emissions 2007–31 (Mt)	Change in investment 2007–31 (billion 2007 rupees)
Accelerated by 10 years	–568	–94
Accelerated by 5 years	–248	–6
Delayed by 5 years	1,392	227

Source: South Asia Sustainable Development Department 2009.

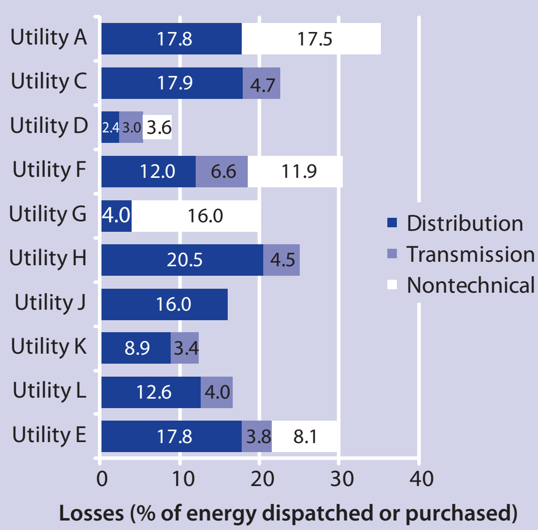
Note: The years are fiscal years. The total investment covers all investments needed to supply the same amount of electricity to consumers as in scenario 1 and includes life extension, efficiency improvement, and new plant construction.

Figure 1.6: T&D Losses by Region, Technical and Nontechnical



Source: Pinto 2010.

Figure 1.7: Share of Technical and Nontechnical Losses in Selected African Utilities



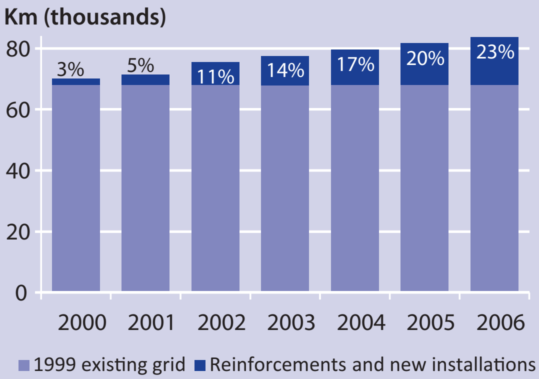
Source: Pinto 2010.

overlooked is the importance of T&D investments in enabling renewable energy technologies. Renewable sources of power are frequently located far from consumption centers; bringing these sources to the market requires investment in T&D. This situation can be seen in different power sectors where the existing or envisaged level of renewable power sources is considerable. Consider, for instance, the case of Brazil. As of 2006, about 90 percent of the installed generation capacity was renewable, primarily hydropower. These sources are located in river basins across the country's vast territory. Exploiting these resources to maintain the large share of renewable energy in the system has required a constant expansion of the transmission system, as shown in figure 1.8.

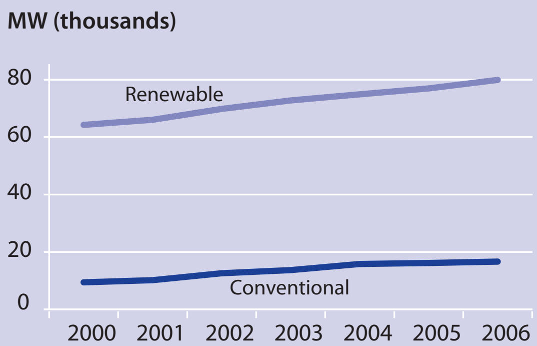
Denmark benefits from a large interconnected system that facilitates the integration and manage-

Figure 1.8: Evolution of the Transmission System and Power Generation Capacity in Brazil

a. Transmission system infrastructure (networks above 230 kV)



b. Installed generating capacity



Sources: Barroso and others 2007; MME and EPE 2006.

ment of a large amount of wind power generation, accounting for about 20 percent of electricity supply in 2009, which is among the highest in the world. The transmission interconnection capacity to its neighboring countries (Germany, Norway, and Sweden) is about 5,780 MW, and the peak demand in the two Danish systems was about 6,500 MW in 2009.[4] The large capacity of the interconnections compared to internal peak demand is because Denmark is an electricity corridor to and from the neighboring countries. The strength of such a transmission system has been crucial in maintaining system operation during conditions where wind power supply has declined sharply.[5] The transmission system is also used to export excess wind power during low-demand periods from Denmark to Norway and Sweden.

Other developed countries have found that achieving a high penetration of renewable energy requires a well-developed transmission system. In the United States, a study directed by the U.S. Department of Energy found that achieving a 20 percent share of wind energy in the country would require investments of about $20 billion in the transmission system (U.S. DOE 2008). This is largely driven by the fact that wind resources are mostly located in the Midwest, far from the consumption centers and existing transmission systems. Similar findings have emerged for the European integrated electricity market, where achieving 20 percent renewable energy by 2020 will require considerable transmission investment across borders.[6]

Objective of This Study

This study seeks to contribute to the objectives outlined in the SFDCC in the area of GHG accounting in the energy sector. The study concentrates on the T&D subsector for two reasons: (1) T&D projects represent a considerable portion of the World Bank's energy portfolio, and (2) the implications of T&D projects on GHG emissions have received less attention than power generation projects. Renewable energy generation, energy efficiency, and other off-grid projects have more available carbon finance–related methodologies than does the T&D sector. The importance of the transmission system in achieving a lower-carbon power sector

[4] Information from energinet.dk (the Danish transmission system operator) and the Danish Energy Agency; refers to nameplate capacities. Actual interconnection capacity depends on network conditions and on the direction of the flow (imports or exports).

[5] See, for example, Ackermann and others (2009) and CEPOS (2009).

[6] See May (2009).

seems unquestionable. Understanding the implications of T&D investment on GHG emissions in the power sector and finding ways to measure these impacts in the context of the SFDCC are the objectives of this report.

The study reviews, assesses, and provides recommendations on methodologies for GHG accounting of electricity T&D projects. Existing methodologies are assessed according to a set of selected principles to test whether they can provide simple and accurate estimates of net emissions at the project level. In addition, the study identifies and conceptually designs new methodologies that may be required to fulfill this objective. The study, along with the analytical efforts on GHG accounting in other sectors, assists in understanding the implications of future application of GHG analysis tools at the World Bank.

The study builds on existing information and methodologies developed under different climate finance mechanisms, and considers some of the fundamental principles in other accounting procedures, such as corporate GHG accounting. Methodologies whose objective is emissions accounting for climate finance mechanisms need to have specific components, such as additionality[7] and ex post monitoring. These methodologies must compute a project's emissions reductions relative to a baseline, which means they compute the project's net emissions. On the other hand, methodologies for corporate GHG reporting estimate a corporation's direct emissions. Generally, such methodologies are similar to those of the Intergovernmental Panel on Climate Change (IPCC) for national GHG inventories and do not require additionality tests. Given the strong corporate mandate for GHG accounting at the project level specified in the SFDCC, and that project-level accounting for Bank projects is not intended for climate finance purposes, the study investigates elements of both accounting approaches. The outcome should be methodologies that can provide simple but reasonable estimates of net emissions impacts for use in the project preparation cycle.

[7] *Additionality* is defined by the UNFCCC as follows: A CDM project activity is additional if anthropogenic emissions of greenhouse gases by sources are reduced below those that would have occurred in the absence of the registered CDM project activity. In other words, the project has lower emissions than a counterfactual "baseline scenario". Justifying additionality involved demonstrating that the project would not have happened without the benefits (financial and otherwise) of the CDM.

2. GHG Accounting Principles Relevant for T&D Projects

The basic principles for GHG accounting are similar across many different sources, although they vary somewhat according to the purpose of the methodology. The GHG Protocol, for example, identifies relevance, completeness, consistency, transparency, and accuracy as key principles (see box 2.1). The IPCC 2006 guidelines highlight that "good practice" inventories are those that "contain neither over- nor under-estimates so far as can be judged, and in which uncertainties are reduced as far as practicable" (IPCC 2006a). This language reflects an emphasis on not just accuracy and completeness, but also on feasibility ("as far as practicable").

The Kyoto Protocol says that emissions reductions under the CDM must be "real, measurable, and long-term." The baseline methodologies used in the CDM must also follow principles included in the CDM Modalities and Procedures. These include estimating emissions reductions "in a transparent and conservative manner" and "taking into account uncertainty" (UNFCCC 2001).

The SFDCC provides some principles to guide the methodology development within this study. They closely follow the practice in the methodologies and guidelines described above. The principles specified

Box 2.1: GHG Protocol Overall Principles for GHG Accounting

Relevance: Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users—both internal and external to the company.

Completeness: Account for and report on all GHG emissions sources and activities within the chosen inventory boundary. Disclose and justify any specific exclusions.

Consistency: Use consistent methodologies to allow for meaningful comparisons of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.

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

Accuracy: Ensure that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy to enable users to make decisions with reasonable assurance as to the integrity of the reported information.

Source: GHG Protocol 2004.

in the SFDCC document are **credibility**, **transparency**, **feasibility**, and **ease of harmonization**. For this particular study, the terms of reference suggest a greater emphasis on feasibility than ease of harmonization, because these proposed methodologies will not be used for carbon finance project applications. The working definitions of these principles are as follows:

- **Credibility/accuracy**: The assurance that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable.
- **Transparency**: The addressing of all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.
- **Feasibility**: The ability for most of the calculations to be carried out using the existing data that would normally be available through feasibility studies and similar documentation prepared for World Bank projects, or for data to be obtained relatively easily by the staff evaluating these proposals.
- **Ease of harmonization**: The assurance of consistency with other widely used GHG accounting methodologies, taking into consideration how they may change over time.

Most GHG accounting systems follow similar principles and acknowledge the tradeoffs among these principles. For instance, a higher degree of accuracy may mean less transparency, because more sophisticated methods and tools may be needed. The emphasis placed on the different principles should be determined by the objectives of the GHG emissions accounting activity. For example, accuracy is a very important principle when accounting is being used for climate financing purposes, because of the risk the higher crediting will compromise the integrity of GHG emissions limitation agreements and regulations. Conversely, for a corporation doing GHG inventory reporting, it may be more important to prioritize transparency rather than accuracy since this allows all stakeholders the opportunity to easily understand and replicate the reporting results.

Corporate and National Inventories versus Project-Level Net Accounting

The methodologies for assessing the GHG emissions impacts of projects and organizations typically fall into two broad categories: corporate or national inventories (sometimes called "gross emissions accounting") and project-level net impacts accounting. **Corporate or national GHG inventories** consider only the increases of emissions from the activities within a specific project activity, company, or country. **Net emissions accounting** for a project, on the other hand, considers how the overall emissions of a larger system may change from the "without project" scenario to the "with project" scenario, which may include decreases or increases in overall emissions as a result of the implementation of the project.[1] The "without project" scenario is called a "business as usual," "reference," or "baseline" scenario. The "with project" scenario is the scenario that includes implementation of the project, which may lead to different emissions than the reference or business-as-usual scenario. An example would be installation of a more efficient fossil fuel–fired boiler. Operating the new, more efficient boiler will still create GHG emissions from the combustion of fossil fuels. Compared to the existing, less efficient boiler, however, the project results in a net decrease in emissions, because emissions in the "without project" scenario are higher than in the "with project" scenario.

Inventory accounting is typically used for calculating the GHG footprints (usually called "carbon

[1] The SFDCC emphasizes the need for GHG accounting activities to follow a net emissions approach, which computes emissions reductions or increases by comparing emissions from a "without project" scenario and a "with project" scenario.

footprints") of companies and organizations, such as the approaches described in the Greenhouse Gas Protocol Corporate Accounting Standard (GHG Protocol 2004) and other corporate carbon footprint models. The same approach is used for national GHG inventories based on the IPCC Guidelines for these inventories (IPCC 2006a). These methodologies identify and provide tools to estimate all the sources of emissions within a defined boundary, whether this is a national boundary or company ownership boundary. Corporate inventory accounting is not restricted to the physical boundary of the project or company, but may also include increases in emissions outside that boundary. For example, the GHG Protocol Scope 2 emissions are from external power plants or other off-site energy production facilities that supply energy to the company, even though the power plants are not physically located at the company site. Furthermore, the GHG Protocol has a Scope 3 that can include other emissions increases upstream and downstream of the company (for example, emissions from producing the equipment used by the company or emissions from company personnel traveling in vehicles not owed by the company). An important example of this in practice has been the analysis of emissions from solar photovoltaic panels and some other renewable electricity technologies, where these technologies have no GHG emissions in operation but may involve substantial energy input to manufacture the components (Knapp and Jester 2001; Gagnon, Belanger, and Uchiyama 2002).

This inventory approach is adopted by many of the companies in the power sector, including T&D companies. The carbon footprint for Transpower, the national transmission utility of New Zealand, provides a useful example of project boundary setting for a corporate T&D *gross emissions* inventory. As shown in table 2.1, Transpower only considered fuel use within offices, owned vehicles, and sulfur hexafluoride (SF_6) in Scope 1. Technical losses for the entire transmission system are not part of the Transpower carbon footprint or gross emissions inventory. This is in line with guidance issued by the United Kingdom's National Grid (2008). Both companies argue that system technical losses should not be included in the utility's carbon footprint because this electricity is not purchased by the transmission company, and the company cannot control the power generation sources, their geographical location, or the generation outputs. This may be the case

Table 2.1: Project Boundary Definitions from Transpower New Zealand's Carbon Footprint

Scope 1: Direct emissions	▪ Petrol used in Transpower vehicles ▪ Diesel used in Transpower vehicles ▪ Bioethanol and biodiesel used in Transpower vehicles ▪ Diesel used in standby generators ▪ Reticulated gas in Transpower House ▪ SF_6 losses from transmission equipment operation
Scope 2: Electricity indirect emissions	▪ Electricity purchased and used for Transpower's own functions
Scope 3: Indirect emissions	▪ Staff business travel (taxis, rental vehicles, mileage claimed in private vehicles) and domestic and international air travel ▪ T&D losses from purchased electricity and reticulated gas used for Transpower's own functions ▪ Office waste to landfill ▪ Electricity consumed to run lifts, common area lighting, and so on (for example, baseload electricity) in noncontrolled leased assets

Source: Transpower 2009.

for a utility where all the technical loss improvement measures that are financially viable with current technologies and regulations have already been implemented.

Net emissions accounting is typically used for climate change mitigation projects to demonstrate that they lead to a net decrease in overall national emissions, even though there may be some GHG emissions associated with the project activity. Net emissions accounting compares the total emissions from the project scenario to the total emissions that would have occurred in the same system without the implementation of the project (that is, the baseline scenario). All of the CDM methodologies, as well as projects in the voluntary carbon market, use net emissions accounting.

For projects using net emissions accounting to qualify for carbon finance, both the baseline scenario and the related concept of additionality are critical. According to CDM rules, "the baseline for a CDM project activity is the scenario that reasonably represents the anthropogenic emissions by sources of GHGs that would occur in the absence of the proposed project" (UNFCCC 2001). This means that the baseline is a hypothetical, or counterfactual, description of what would have happened without project implementation (Spalding-Fecher 2002; Lee and others 2005; Sharma and Shrestha 2006). This may or may not be similar to the current situation or historical emissions. For example, if the project is to replace industrial equipment with more efficient units, but the existing equipment has only one year of useful life left, using the existing old equipment as the baseline for the future life of the project is clearly not appropriate. This is also why the concept of additionality is important in the net emissions accounting methodologies used for carbon finance mechanisms. According to the CDM rules, "a CDM project activity is additional if anthropogenic emissions of GHGs by sources are reduced below those that would have occurred in the absence of the registered CDM project activity" (UNFCCC 2001). In other words, the project must reduce emissions beyond what would have happened anyway to receive credits for net emissions reductions (Baumert 1999; Shrestha and Timilsina 2002). While the concept of baselines is always important for assessing a project's net emissions impacts, how additionality is addressed is not as clear outside of the carbon finance arena. This is discussed in more detail in the next section.

While most projects in the energy sector will emit GHG emissions, the net impact of the project may be a reduction in GHG emissions if the project scenario emissions are less than emissions from the baseline scenario. This does not mean that the project has a negative emissions inventory, but that the total system emissions in the project scenario are less than those in the baseline scenario. An example of the difference would be a gas-fired power station that emits significant GHG emissions, but that could have negative net emissions impact if it replaces a more carbon-intensive coal-fired power station. A corporate emissions inventory for the utility owning this power station would still show positive emissions, but the net emissions impact for the project investment could be negative. At the project level, net emissions accounting gives a more comprehensive picture of the impact of a project or intervention on overall national emissions. Therefore, the SFDCC recommends studying net emissions accounting approaches for World Bank–funded T&D projects.

Additionality and Net Emissions Accounting

Within the methodologies developed for carbon finance projects such as the CDM, there is a strong focus on tools and specific tests to prove additionality. Project proponents must justify that the project would not have been implemented without the benefits of carbon financing to show that it is not part of the baseline scenario. Because the credits from these projects are used to offset emissions from other countries or companies, without a strict additionality test, the purchasers of the credits would be emitting more GHG emissions without compensating for these emissions elsewhere. In the CDM framework, if a country purchased certified emissions reductions from a project that was not additional and used these credits for compliance with their emissions reduction targets, they would not actually have met those targets because their emissions were not offset by the business as usual CDM activity (Greiner and Michaelowa 2001; Shrestha and Timilsina 2002; Tanwar 2007).

Carbon finance projects evaluate additionality using a variety of tools and tests. The most commonly used tool is investment analysis, where project proponents provide a financial analysis of the project showing that it is not viable without the revenue from the sale of carbon credits. The challenge is how to objectively present the evidence for this financial analysis in a way that it can be audited by a third party (Bode and Michaelowa 2003; Ellis, Corfee-Morlot, and Winkler 2007). In practice, this has been one of the most difficult issues to address in the CDM and similar programs (Ellis, Corfee-Morlot, and Winkler 2007; Schneider 2007). A number of standard tools have been approved by the CDM Executive Board, as well as guidelines on how to apply these tools and what type of evidence may be used in their application.[2]

The question of additionality does not arise for corporate inventory accounting, because this approach only reflects the actual emissions of the project (that is, there is no "without project" scenario). For net emissions accounting, a "without project" scenario, or baseline, is required to compare the project emissions to those that would have occurred without the project.

As with all carbon accounting, additionality is intimately related to the selection of the baseline scenario. For example, consider a technical loss reduction project that replaces substation equipment. Typically, the annual energy savings, and therefore carbon savings, from this type of project would be calculated from historical technical losses versus technical losses after the project was implemented. Lifetime energy and emissions savings would then be annual savings multiplied by the economic life of the new T&D equipment. But what if the existing equipment was due to be replaced in any case in three years because it had reached the end of its useful life? In that case, should the baseline scenario itself include decreasing technical losses over time? This would reduce the calculated net impact of the project.

The *GHG Protocol for Project Accounting* describes the typical "project-specific approach" to additionality that is used in the CDM and many other carbon finance programs:

> The project-specific approach to additionality aims to identify a distinct baseline scenario specific to the project activity, in spite of subjective uncertainties involved in doing so. The reasoning behind this approach is that a rigorously identified baseline scenario is all that is necessary to establish additionality: if the project activity is different from its baseline scenario, it is additional. However, because identifying a baseline scenario always involves some uncertainty, many observers argue that this approach should be combined with explicit additionality tests (GHG Protocol 2005a).

The GHG Protocol also describes a second approach, which is the "performance standard approach" to additionality:

> This is done by developing a performance standard, which provides an estimate of baseline emissions that would otherwise be derived from baseline scenarios for each project activity. Under this approach, the presumption is that any project activity will produce additional GHG reductions if it has a lower GHG emission rate than the performance standard. A performance standard can provide a consistent way to address additionality for a number of similar project activities and avoids having to identify individual baseline scenarios. The challenge is to set the performance standard at a sufficiently stringent level to ensure that, on balance, only additional GHG reductions are quantified.

[2] See, for example, UNFCC 2008 and UNFCC 2010.

It is important to remember, however, that the *GHG Protocol for Project Accounting* (GHG Protocol 2005a) is designed—at least in part—to support projects that could generate carbon credits in the carbon markets outside of the CDM. As discussed earlier, the objective of this study is to propose methodologies for T&D projects that will not be used for carbon financing or the creation of any tradeable carbon credits. World Bank–funded T&D projects seek to address development objectives in the electricity sector, such as extending the coverage of electricity, improving the reliability of services provided, or reducing electricity losses, among others. Even though the main objective is not to reduce emissions and receive any form of carbon credit, Bank interventions may have implications for GHG emissions. In several cases, T&D projects could not be implemented without Bank support, at least at the scale and scope defined with client counterparts in each project the Bank supports. In this sense, World Bank T&D investments can be said to be "additional" in CDM terminology.

Nevertheless, when developing baseline scenarios for the T&D projects described later in this report, a key question is whether historical data are an accurate proxy for the baseline scenario. If technical loss rates are changing dramatically (either increasing or decreasing), it may not be appropriate to use these for the baseline scenario against which a technical loss reduction project is compared. Similarly, for projects that replace T&D equipment, it may be appropriate to limit the period over which emissions reductions are assessed to the remaining lifetime of the equipment. This is standard practice in most CDM baseline methodologies.

Project Boundaries and Double Counting

Setting the project boundaries is another critical element of any emissions accounting approach. As the *GHG Protocol for Project Accounting* notes:

> In a full "life-cycle analysis" of GHG emissions for a particular product (or project), for example, one could in principle examine GHG emissions associated not just with inputs to the product, but also the inputs to those inputs, and so on up the product's "value chain." Generally, the cost and time requirements for this kind of analysis are prohibitive….The secondary effects for many types of GHG projects can be relatively small, particularly for small projects…. GHG project accounting requires decisions about the trade off between accounting for secondary effects and the time and effort required to do so (GHG Protocol 2005a).

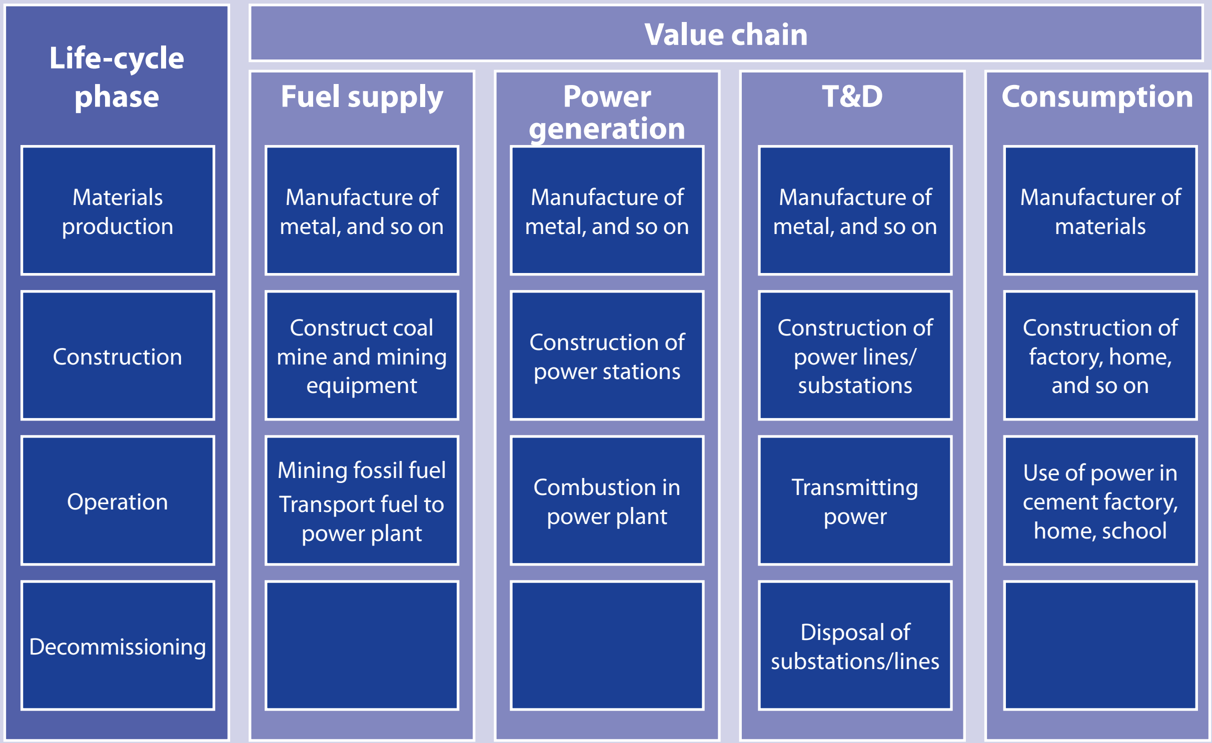
The World Bank's *Handbook on Economic Analysis of Investment Operations* (1996) states that choosing the right project boundary for broader economic and environmental impacts of projects is not always obvious, because these impacts may extend beyond the ownership boundaries of the project or the traditional financial analysis boundaries.

For T&D projects, two different dimensions must be considered for the physical project boundary (see figure 2.1). One is the **stage of value chain** for electricity supply, starting with the production fuel for power stations, through power generation, T&D, and finally to consumption by the end user. These activities, and the emissions associated with them, would generally all be performed within the same year.[3] The most important distinction here is between impacts of generation emissions and non-generation emissions. In other words, T&D projects will have impacts at the T&D value chain stage, but they will also have impacts in other value chain steps—particularly power generation. As discussed earlier, the explicit goal of many T&D projects is to affect power generation, so this category of emissions impacts must be considered as part of the project boundary discussion.

The second dimension is the **life cycle over time** of all the equipment and facilities at each stage of the

[3] Because power generation companies may stockpile some fuel, there will be a time delay between production of the fuel and combustion in the power plant. This will generally not be more than a few weeks, however, for fossil fuels.

Figure 2.1: Sources of Electricity System Emissions: Life-Cycle Phase versus Value Chain Step



Source: Authors' analysis.

value chain. Whether it is a power station, transmission line, or coal mine, all of these facilities have input materials, a construction phase, an operational phase, and finally a decommissioning phase. While these phases occur at different times—and the entire cycle may cover decades—they are all related to the ultimate production and delivery of electricity. Each of the boxes in figure 2.1 will have GHG emissions from a variety of sources, as explained in more detail in "The Structure of T&D in World Bank Lending Operations," page 21.

For calculating the nongeneration emissions impact of a T&D project, it would be ideal to include all of the life-cycle emissions for the T&D stage of the value chain. This would include emissions related to the manufacture of materials, as well as construction and operation of the lines and substations. Decommissioning may be much more difficult to estimate, and generally in developing countries, T&D systems are only upgraded and replaced not dismantled or removed. Whether the embodied emissions in the materials used can be included will depend on the availability of data, and also on how large these emissions are likely to be relative to emissions in other phases. The potential project boundary for nongeneration emissions from a T&D project is illustrated in figure 2.2. The practice of current methodologies and companies in the industry of estimating nongeneration emissions is reviewed in "The Structure of T&D in World Bank Lending Operations," page 21.

Project Boundary for Generation Emissions Impact

In assessing the generation emissions impact of a T&D project, the focus is on which parts of the electricity system emissions are likely to change from the baseline scenario to the project scenario. Within the nongeneration emissions project bound-

Figure 2.2: Potential Project Boundary for Nongeneration Emissions from T&D Projects

Life-cycle phase	Value chain			
	Fuel supply	Power generation	T&D	Consumption
Materials production	Manufacture of metal, and so on	Manufacture of metal, and so on	Manufacture of metal, and so on	Manufacture of materials
Construction	Construct coal mine and mining equipment	Construction of power stations	Construction of power lines/ substations	Construction of factory, home, and so on
Operation	Mining fossil fuel Transport fuel to power plant	Combustion in power plant	**Transmitting power**	Use of power in cement factory, home, school
Decommissioning			Disposal of substations/lines	

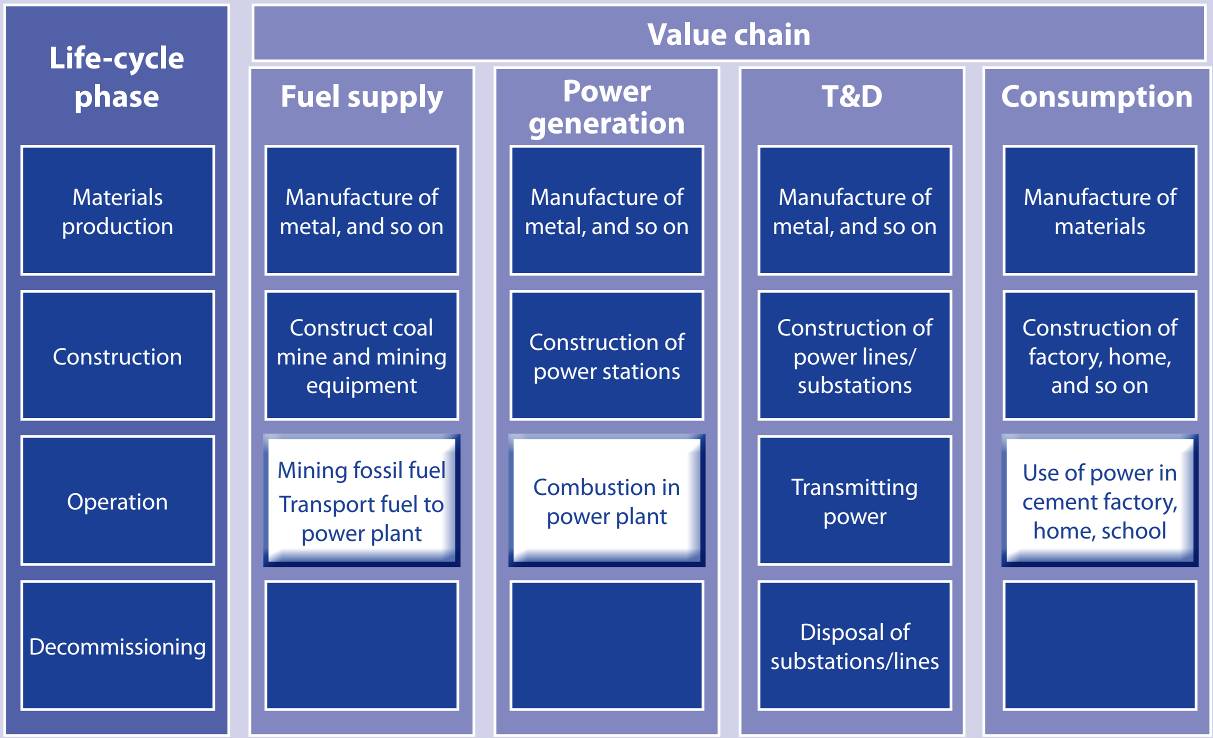
Source: Authors' analysis.

ary defined in figure 2.2, there are no emissions from the baseline scenario, since there would be no construction or operation at that site if the project had not been implemented. Within those boxes, therefore, the net emissions impact is based only on the project scenario emissions—in other words, it is always an increase in GHG emissions equivalent to project emissions.

Within the power generation subsector, however, emissions could change significantly. As an example, discussed in more detail in the next chapters, a technical loss reduction project does not have any impact on emissions at the transmission or distribution site, but it does reduce the amount of power generation required to meet consumer demand. Baseline emissions within power generation and fuel supply, therefore, could be significantly higher than the project scenario emissions in those boxes. Figure 2.3 illustrates the most important areas where T&D projects could affect emissions from other stages of the value chain. The reason other life-cycle phases are not included for other value chain stages is that these emissions are generally very small compared to emissions from operation. This is discussed in more detail in chapter 5.

While power generation and fuel supply are clearly affected by many T&D projects, the impact on downstream consumption is more complex. For example, if an investment in a new distribution line and substation supplies power to a new cement factory, the project scenario could include process emissions and fuel combustion emissions from that cement factory. For most T&D projects being analyzed by the World Bank, however, the consumer of the additional power is not specified and may be a mix of many households, business types, and industries, so analyzing this would be very difficult. In addition, there are no examples of CDM methodologies that take into consideration downstream emissions from the consumption of a product pro-

Figure 2.3: Possible Impacts of T&D Projects on Generation and Other Value Chain Stages



Source: Authors' analysis.

duced by the project activity. Since emissions from combustion during power generation are the major contributor to emissions from the energy sector globally, it makes sense to focus on fuel combustion in power generation as the key value chain step before the T&D operation.

Based on current practice (see the following chapters) and the reasons explained earlier, the boundary and review of potential impacts and methodologies for net impacts of T&D projects focus on combustion emissions at power plants. Downstream emissions as a result of energy consumption are not taken into account.

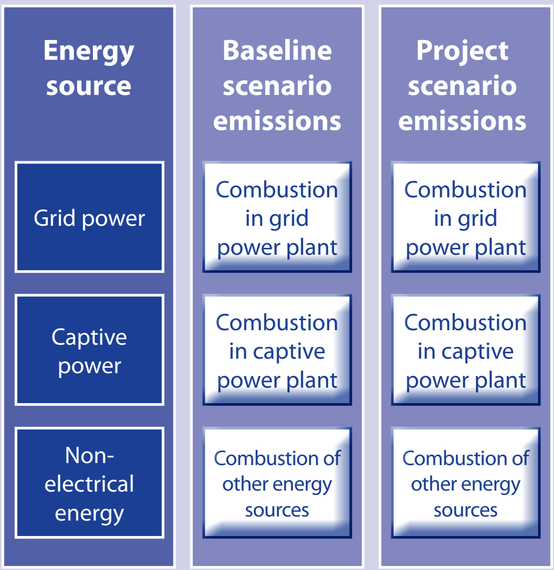
Because the electricity supplied by a new T&D project could displace nongrid sources of energy (for example, captive/backup power or other fuels in the case of electrification), baseline and project emissions could be assessed for all of these sources (see figure 2.4).

Double Counting

For nongeneration impacts analyzed using a typical corporate inventory approach, extending the project boundary from the physical T&D equipment site to include construction and materials manufacture stages would essentially mean an overlap of emissions estimates across sectors. In other words, if a construction company or steel tower manufacturing company in that country also created an emissions inventory, some of these emissions would overlap with those that had been included in the T&D project inventory. This is also the case for emissions from power and heat consumption, because the emissions from power generation would also be attributed to the utility providing the power.

For assessing the generation emissions impact of T&D projects, there is an important overlap between different projects and organizations within the power sector, so it is not possible to simply sum

Figure 2.4: Potential Baseline and Project Emissions Sources for Assessing Net Emissions Impacts on Generation



Source: Authors' analysis.

all of the net emissions impact for a total World Bank portfolio emissions impact. For example, consider two projects funded in the same country, one a transmission line that connects two subnational grids and one a new hydropower station in a subnational grid that will now send more power over the new line to another fossil fuel–dominated subnational grid. The net impact on emissions from the new transmission line could include the displacement of fossil fuel power in one subnational grid by hydropower in the other subnational grid, since it is the new line that allows this flow of power. The net emissions impact of the renewable power station, however, might also be based on a baseline scenario of fossil fuel power if this was the predominant energy source on the existing grids. Therefore, adding the net emissions impacts of these two projects would overstate the total impact on national emissions, because some of the fossil fuel–fired electricity savings claimed by the transmission upgrade are also being claimed by the renewable power plant. Thus, while net emissions accounting is very valuable on a project level, it could be misleading to use this approach to assess the impact of the entire World Bank lending portfolio. That said, the net emissions approach gives a much more comprehensive means to assessing the overall impact of World Bank–funded projects, since it more accurately reflects the impact of a given project across the entire energy sector.

3. Categorization of Project Types and Emissions Impacts

The World Bank T&D project interventions are very different from traditional private sector or CDM transactions. This section provides an overview of the diversity of the T&D projects at the Bank and their emissions impact based on the technologies supported, the objectives being pursued, and the scope of the projects.

The Structure of T&D in World Bank Lending Operations

The WBG's lending portfolios include support for investments in a full range of electricity system components: generation, transmission, and distribution. In addition to providing support for investments in these areas, most operations would also include components to support policy reforms, capacity building, and institutional strengthening. Between fiscal 2003 and 2009, the World Bank approved 98 loans that had T&D components. This lending totaled $6.143 billion in 53 countries and some African regional projects (see annex B).

Lending operations that support T&D investments usually support not a single project but a collection of projects. For instance, a lending operation could contain two components for T&D—one for a new transmission line in the interconnected system and a second component to finance the expansion of several distribution substations in different areas of the grid. Other operations support projects in all segments of the electricity sector. This type of operation is more frequent in International Development Agency countries, where pooling of resources among different donors is used to finance large-scale investment plans. In IBRD countries, it is also common to find loan packages that support some of the priority projects from T&D utilities' investment programs. Project components and subcomponents are usually structured around the main objectives of the lending operation (for example, increasing access and increasing transmission capacity).

Other factors play an important role in the structuring of lending packages. One of these is the need to perform discrete environmental or economic analyses on site-specific investments as per World Bank operational procedures. For instance, a new transmission line requires higher environmental and social safeguards, whereas an existing substation has lower requirements. This usually leads to the separation of two components for analysis during project preparation and appraisal. A similar separation may be triggered by the need to analyze the economic viability of different types of projects. Another factor that affects the definition of lending packages is cofinancing. Cofinanciers, as well as the loan recipient, may have preferences for or restrictions on financing certain types of projects. For instance, some financiers may not be able to finance technical assistance with loan resources; others may have funds available only for renewable energy projects.

World Bank T&D projects are therefore quite different from typical carbon finance projects, such as CDM projects, or typical private sector power investments. In addition to the factors discussed above, traditional carbon finance projects or private sector operations have clearer boundaries. A typical carbon finance project could be a single wind farm, a few minihydro projects, or a well-defined transmission concession. CDM and private sector transactions are usually implemented by a single entity, while World Bank loans may be supporting, at the same time, investments implemented by different agencies (for example, the ministry, a vertically integrated utility, a distribution company, and/or a rural electrification agency).

Other aspects of World Bank operations that may factor into the applicability of existing methodologies and the design of appropriate solutions for GHG accounting are the following:

- **Technical diversity of projects:** A project can contain components at different voltages in the system. Although all components may be addressing a given strategy, components are analyzed differently from a technical, economic, or environmental and social safeguards perspective.
- **Information availability**: Current data availability is driven by formal operational requirements, which may affect the feasibility of some GHG accounting approaches. The amount and quality of data also depend on the risks each component may be facing (for example, environmental, financial, or technical). For example, for a large transmission interconnector project, fairly detailed short-term and long-term load flow and power system economic studies may be required to appraise a project, while a substation upgrading could be assessed based on simpler data such as substation capacity and local demand growth.
- **Timing and implementation readiness of investments**: The subcomponents of an overall T&D program may be rolled out over time, which makes ex ante data availability a challenge. For example, in a large rural electrification project, it is likely that, at time of approval, only a subset (perhaps 10 percent) of the grid extension projects have been identified at the level of engineering detail required for implementation. The remainder of the projects are designed and implemented as the loan implementation progresses.

The combination and variety of World Bank projects in the electricity sector mean that the tools for estimating GHG impacts of T&D projects need to be more comprehensive to make their implementation feasible and cover the effects of the variety of interventions that could be included in a loan. Even without the inclusion of power generation, many T&D investments will have multiple impacts on the grid operation and therefore on GHG emissions. It is the objective of this work to identify methods that can be used easily in the context of the loan preparation cycle. For this reason, and given the characteristics of World Bank interventions described above, the discussion begins by categorizing projects according to their objectives.[1] The objectives largely define the way in which projects are analyzed from the technical, economic, and environmental and social safeguards perspectives, which provides a familiar framework for project teams to analyze GHG implications. Linking project objectives to GHG implications or impacts could therefore be a suitable approach to feasibly start rolling out GHG accounting of T&D interventions.

Project Categorization by Objective

A review of all the World Bank loans approved from fiscal 2003 to 2009 that included T&D components, as well as a review of the most frequently used indicators in the results matrix of such loans, identified a set of project-level objectives tied to larger development goals common to the T&D portfolio. Such project objectives can be related to specific impacts on GHG emissions, which could then be quantified with specific GHG emissions accounting tools. Where a project has multiple objectives, multiple tools or modules should be applied so all potential GHG impacts can be captured. This will be particularly true when net emissions are assessed.

For the purposes of this report, projects are categorized by the following objectives:

- **Technical loss reduction:** Reduce technical losses in the transmission or distribution system so that less energy is lost between power genera-

[1] From here on, *project* is used to describe the smallest component or subcomponent in a loan whose technical and economic assessment is performed separately from the other components.

tion and end users. The main impacts on GHG would be the changes (reduction) in power generation.

- **Increased reliability**: Increase the reliability of electricity supply, so that consumers have fewer and/or shorter supply interruptions. The impact on GHG emissions could be increased grid generation and reduction of on-site (backup) power generation.
- **Distribution capacity expansion**: Increase the overall capacity to distribute electricity, so that additional power generation can be supplied to existing growing demand. An impact of this objective would be an increase of grid generation, with displacement of other power sources.
- **Electrification**: Connect new consumers to the grid, thereby displacing other sources of electricity (or even nonelectric energy sources).
- **Transmission capacity expansion:** Increase the overall capacity to transmit electricity over significant distances, so that additional power generation can reach different areas of the transmission system, such as distribution centers. This would increase power generation and potentially displace other power sources.
- **Cross-border trade:** Increase electricity trade between countries by constructing interconnectors between their national grids. This could also occur within a single country, if two major grids that were previously not connected can now trade power through a new transmission line.

This classification is not intended to imply that a particular project pursues only a single specific objective. It is possible that a capacity expansion project, for example, could have an impact on reliability, or that a technical loss reduction project could also be improving electricity access.

As discussed in the previous chapter, when assessing the net emissions impacts of these different project types, one of the important features of T&D projects is that their impact on generation emissions may be greater than their nongeneration emissions. In other words, although all of these projects will have positive nongeneration emissions, the net impact of the project on emissions could be negative, so that overall system emissions are lower after project implementation.

Categorization of Emissions Impacts

The first distinction among the GHG impacts of T&D projects is nongeneration versus generation impacts. The emissions at the physical T&D project site do not have a corresponding baseline, since those activities would not have occurred without the project. Assessing power generation impacts, on the other hand, requires the development of a baseline scenario to estimate the change in emissions from power generation plants before and after the project is implemented.

Within generation impacts, there is an important distinction between the different project categories and how these affect generation emissions outside the physical boundary of the transmission system. Affecting generation output is one of the main objectives of technical loss reduction, but this does not require direct actions to increase or decrease generation output by generators. In other words, if a technical loss reduction project brings electricity production down by 2–3 percent while delivering the same amount of power to end users, no additional action is needed by the power generation subsector to achieve this reduction in energy use and emissions. For increased reliability, capacity expansion, electrification, and cross-border trade, however, these T&D projects will deliver more electricity to consumers and require actions by other parts of the power sector. These actions could be additional investment or a change in operations, as in the reduced operation of backup power generators after an increased reliability project is implemented. There will be cases where, in the short term, excess capacity in existing plants allows an increase in power generation without investment, but other changes may be required such as dispatch rules. In the long term, a transmission interconnection can have important impacts on generation investment, but actions in generation investment cannot be directly triggered by the transmission line. Without new power generation, which will be built if many other conditions exist, there would be no reason for investment in large T&D systems. More importantly, projects other than technical loss reduction have impacts through displacing other power generation sources outside the grid. This makes for some uncertainty about the baseline, since the alternative energy source must be identified to assess the net emissions impacts.

Thus, two categories of GHG impacts on power generation by T&D projects are distinguished: **direct generation effects** and **indirect generation effects**. The description of the three categories of emissions impacts is presented in table 3.1. The remainder of this report is structured around these three categories of emissions impacts.

In these definitions, the physical boundary of the T&D project (as opposed to the boundary in terms of emissions sources) consists of the physical site(s) where the T&D project will be constructed. An example would be substations, transmission lines, and the right-of-way corridor for a transmission expansion project. Actions outside the physical boundary of the project could include investment in power generation, changes in dispatch, or changes in the operation of nongrid generators or energy sources.

These definitions introduce an important distinction in how T&D investments affect power generation. For instance, an international interconnection project could have impacts in power generation over the short and long terms. In the short term, existing cleaner and cheaper power generation in one system could displace more polluting power generation in the other. This will not happen immediately, because the generators will have to agree to new integrated dispatch rules or other forms of dispatch coordination. In the long term, the integrated market will lead to an increase in generation capacity and efficiency. However, for these new investments to materialize, other financial, legal, and regulatory conditions are required, which are outside the control of the T&D project investors and operators.

Since indirect impacts will occur only if these other actions take place, these emissions are not fully attributable to the project, although the project contributes to these emissions reductions or increases. Direct emissions can be attributed to the project. All impacts are analyzed over the same project life used in the technical and economic analysis performed during the Bank's project appraisal.

Table 3.1: Categories of T&D Project Impacts on GHG Emissions Used in This Study

Category of emissions impact	Description
Direct nongeneration effects	Similar to standard corporate or national inventory. Emissions that occur within the physical boundary of T&D project, and possibly through the life cycle of that equipment.
Direct generation effects	Effect on short-term and/or long-term generation emissions that does not require any other actions outside the physical boundary of the T&D project. This would be the case for technical loss reduction projects.
Indirect generation effects	Effect on short-term and/or long-term generation emissions that requires actions outside the physical boundary of the T&D project. This would be the case for increased reliability, capacity expansion, electrification and cross-border trade.

Source: Authors' analysis.

Relevant GHG Methodologies Reviewed

Numerous methodologies, reports, and studies address the GHG impacts of T&D projects. Although their objectives may differ (that is, corporate reporting or crediting), they provide important information on possible alternatives for the World Bank's GHG emissions accounting. These approaches are listed in tables 3.2 and 3.3 and discussed in chapters 4 and 5.

Table 3.2: GHG Measurement Methodologies for the Direct Nongeneration Emissions Impacts of T&D Projects

T&D guidelines	*2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3, Ch. 8.2 Emissions of SF_6 and PFCs [perfluorocarbons] from electrical equipment (IPCC 2006c)
Tools applied within the WBG	IFC Carbon Emissions Estimator Tool (IFC 2009)
Tools applied to power generation, transmission, and distribution case studies	▪ Transpower (New Zealand) carbon footprint (Transpower 2009) ▪ *Life Cycle Assessment of Aluminium Smelter in Greenland* (Schmidt and Thrane 2009) (uses "EcoInvent" as the source for T&D) ▪ "Eco-Balance of a Solar Electricity Transmission from North Africa to Europe" (May 2005) ▪ *Life Cycle Inventories of Energy Systems: Results for Current Systems in Switzerland and Other UTCE Countries* ("EcoInvent") (Dones and others 2007) ▪ *Emissions of GHGs from the Use of Transportation Fuels and Electricity*, Argonne National Laboratory (DeLuchi 1991)

Source: Authors' analysis.

Table 3.3: GHG Measurement Methodologies for the Generation Emissions Impacts of T&D Projects

Power sector guidelines	▪ *GHG Protocol for Project Accounting* (GHG Protocol 2005a) ▪ Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects (GHG Protocol 2007) ▪ *Greenhouse Gas Assessment Handbook* (World Bank 1998), Ch. 3.6.2 Guidelines for Energy Conversion and Distribution Projects ▪ *Manual for Calculating GHG Benefits of GEF Projects: Energy Efficiency and Renewable Energy Projects* (GEF 2008)[a]
CDM baseline and monitoring methodologies[b]	▪ AMS II.A "Supply-side Energy Efficiency Improvements—Transmission and Distribution" (ver10) ▪ AM0035 "SF_6 Emission Reductions in Electrical Grids" (ver01) ▪ AM0045 "Grid Connection of Isolated Electricity Systems" (ver02) ▪ AM0067 "Methodology for Installation of Energy Efficient Transformers in a Power Distribution Grid" (ver02) ▪ AM0079 "Recovery of SF_6 from Gas Insulated Electrical Equipment in Testing Facilities" (ver01) ▪ NM0272 "International Interconnection for Electric Energy Exchange" ▪ NM0269 "Reduction of Emissions through One Way Export of Power from Lower to Higher Emission Factor Electricity System"

Source: Authors' analysis.

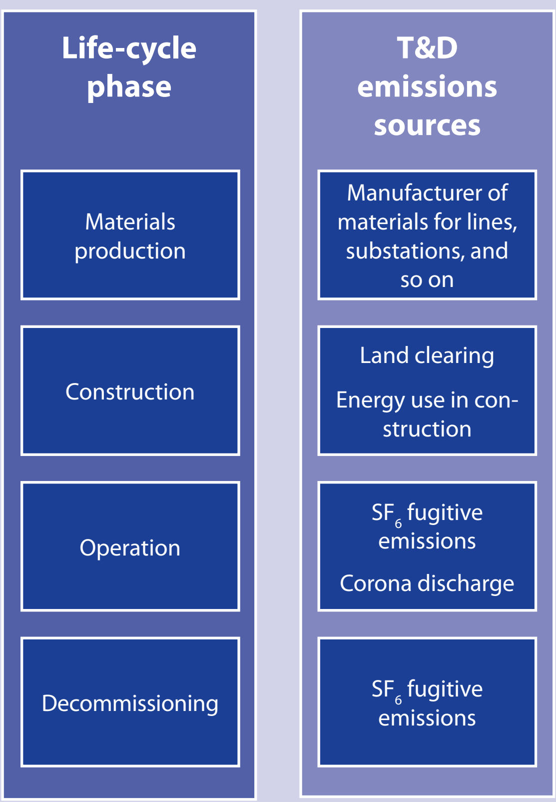
a The GEF manual does not cover T&D projects, but only investments in new renewable power and energy efficiency.

b Approved methodologies can all be accessed at cdm.unfccc.int/methodologies/PAmethodologies/approved.html so no further reference is provided in this document.

4. Direct Nongeneration Impacts of T&D Projects

This chapter discusses each of the possible emissions impacts that should be included in the direct non-generation impacts, for which type of investments they may be relevant, and how existing methodologies address these impacts. The direct nongeneration effects of T&D projects are based on emissions sources in the construction and operation of the T&D system, as shown in figure 4.1.

Figure 4.1: Potential Emissions Sources for Direct Nongeneration Emissions from T&D Projects



Source: Authors' analysis.

Embodied Emissions in Construction Materials

The construction of T&D projects consumes large quantities of aluminum, concrete, other 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 new T&D projects creates some upstream emissions in the manufacture of the materials used. The issue is whether the magnitude of emissions is likely to be great enough to merit the time and effort to calculate them.

Review of Existing Methodologies

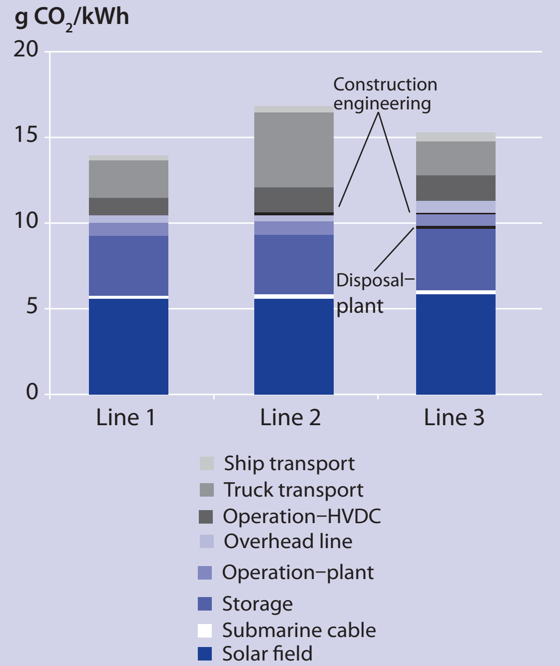
International Finance Corporation Carbon Emissions Estimator Tool (IFC CEET): This tool includes a section on embodied emissions from construction materials, such as metals, composite materials, plastics, and miscellaneous equipment. The project proponent must supply the total quantities of materials used, and the tool provides a table of default embodied emission factors taken from the Agence Française de Développement's "Première analyse des émissions des projets AFD."

EcoInvent: This is not a methodology, but rather a database that includes a variety of environmental impacts from the energy sector. The EcoInvent database includes T&D infrastructure requirements such as metal and wood, but does not appear to include the embodied emissions in these materials. The database covers only European energy systems, so it reflects the power generation mix, T&D system characteristics, and material availability for Europe only.

May (2005): This analysis of life-cycle environmental impacts of transmitting solar power from North Africa to Europe includes embodied emissions in materials based on the Umberto material flow software, using input data from the manufacturer of the lines (ABB), supplemented with the Umberto and EcoInvent databases and other secondary sources. Because this case study analysis was based on European-sourced materials, the EcoInvent European energy database was appropriate for electricity and other energy sources. Materials for the high-voltage DC lines account for 0.4–0.6 kg CO_2e/MWh, while operation of the line (ohmic resistance losses only) is 0.8–1.5 kg CO_2e/MWh (see figure 4.2).

The case study of a long-distance transmission line between Ethiopia and Kenya presented in box 4.1, based on the feasibility study report (FSR) for this investment, shows that embodied emissions in a long-distance transmission line such as this are much less than 1 percent of typical fossil fuel power station combustion emissions.

Figure 4.2: Life-Cycle GHG Emissions for Long-Distance Transmission of Solar Power for North Africa to Europe



Source: May 2005.

Box 4.1: Example of Embodied Emissions in Long-Distance Transmission Line

The embodied emissions of materials are most likely to be significant in T&D projects that involve extensive infrastructure relative to the amount of power delivered, such as long-distance transmission lines. In addition, for projects with long line lengths, the materials in the lines will far outweigh the materials in substations and other equipment. An example of this is the Ethiopia Kenya power systems interconnection project (see chapter 7 for more detail). This project involves 1,200 km of double 772 mm^2 line. The weight of this line, according to the manufacturer, is 1.91 t aluminum and 0.68 t steel per kilometer (Sural 2010). This amounts to 4,575 t aluminum and 1,628 t steel for the entire line. For embodied emission factors, the Global Emission Model of Integrated Systems database (Öko Institute for Applied Ecology 2009) provides 14.5 tCO_2e/t aluminium (Germany) and 1.6 tCO_2e/t steel (mix of electric arc furnace [EAF] and basic oxygen furnace [BOF] processes, Germany).

This yields total emissions of 68,294 tCO_2e. Over the lifetime of the line (2012–27), the projected electricity transmitted is 106,672 GWh (Fichtner 2008). Thus, embodied emissions are 0.64 kg CO_2e/MWh. Given that fossil fuel power sources typically have emissions of 600–1,100 kg CO_2e/MWh, this is one-tenth of 1 percent of those emissions.

Assessment of Available Methodologies

Calculating embodied emissions is straightforward if the underlying data for materials consumption and emission factors are available. The challenge is that most T&D project appraisals would not contain a detailed materials inventory, since this is only developed by a quantity surveyor after detailed design studies are complete—which would be well after loan approval.

More importantly, the embodied emission factors for materials are highly dependent on their source. For example, steel manufactured in Brazil will have much lower embodied emissions than steel manufactured in South Africa, since the grid emission factor in Brazil is almost 90 percent lower than in South Africa (0.1 versus 1.0 tCO_2/MWh).

Creating a database for embodied emissions of materials would clearly be beyond the scope of this report, or of most carbon accounting methodologies, because of the complexity of life-cycle issues. If this source is to be included, the emission factors must come from existing, reputable databases. The databases for embodied emissions—for example, EcoInvent, the *Global Emission Model of Integrated Systems* (Öko Institute for Applied Ecology 2009), the *Inventory of Carbon & Energy* (Hammond and Jones 2006)—generally focus on Europe, and so would need to be modified for materials sourced in developing countries.

Where T&D projects are of sufficient scale to merit the necessary data collection, this area of direct nongeneration emissions could be considered, but it will not be possible for the majority of projects without significant additional time and cost.

Energy Use in Construction

There is on-site energy use in the actual construction of a T&D project, primarily in the form of transport fuel for construction vehicles and the shipping of components. This energy use could be considered a component of direct nongeneration emissions, because it is at the project site, even though it occurs before the actual operation of the T&D project. This source of emissions is likely to be very small compared to the lifetime energy and emissions impacts of the T&D project.

Review of Existing Methodologies

IFC CEET: This tool includes an equation for emissions from fuel consumption in mobile vehicles during construction. The project proponent must supply the quantities of fuel used, and the tool provides a table of default calorific values and carbon emission factors taken from IPCC and the GHG Protocol.

DeLuchi (1991): This comprehensive assessment of electricity sector life-cycle environmental impacts from the Argonne National Laboratory in the United States finds that emissions from the construction of power plants, which are also highly material intensive, are equivalent to 3–5 kg CO_2e/MWh (table 13, p. 50), but does not include these in the emissions from power stations. The study does not provide a similar figure for T&D investments, because it does not include construction emissions from T&D systems.

May (2005): See page 28.

Assessment of Available Methodologies

The methodological approach to construction emissions is straightforward, but calculating this source is only possible if the underlying data are readily available, particularly data on the quantities of fuel consumed by construction vehicles. Data for fuel calorific values and emission factors are available from IPCC and GHG Protocol, but the quantity of fuel must come from the project documents. This information is not something that is evaluated even during the detailed design phase of T&D projects.

Land Clearing

New construction of long-distance lines, or even of distribution lines and substations, may affect carbon stored in biomass and soil. An obvious example would be clearing 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 of 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.

Review of Existing Methodologies

AM45: Leakage emissions for electrification projects include emissions from transmission line construction.[1] Leakages related to deforestation in the construction of interconnection lines are calculated as follows:

$$LE_1 = A_{def} \times L_C$$

Where

LE_1 = Leakage emissions to be accounted for in the first year of the project crediting period

A_{def} = area of land deforested, in ha

L_C = carbon stock per unit area (above ground, below ground, soil carbon, litter, and dead biomass), in t of CO_2 per ha

This approach is also used by other proposed baseline methodologies, as well as the proposal from the Methodologies Panel of the CDM Executive Board on transmission lines for cross-border trade. The only registered project design document for AM45 is "Celtins and Cemat Grid Connection of Isolated Systems." This Brazilian electrification program estimated land clearing emissions of 39,150 tCO_2 in the state of Mato Grosso. The total electricity delivered in the first seven years, as the electrification program is rolled out, is 212,576 MWh, or 50 kg CO_2/MWh. If the last year of the program is used to approximate the ongoing delivery of power, the 20-year total would be 2,976,062 MWh, and the land clearing emissions would be 13 kg CO_2e/MWh. Note that, unlike ongoing emissions such as SF_6 or corona discharge, land clearing emissions per MWh are sensitive to the economic life used for the assessment of the T&D project.

IFC CEET: This tool was developed for any investment project undertaken by the IFC, and so covers many sectors. It includes a section on land clearing that can be applied for any project type. Land clearing emissions are the product of area cleared and biomass density (above and below ground). The tool also includes a table of emission factors (aboveground and below-ground biomass density) for a large variety of vegetation types, sourced from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

Assessment of Available Methodologies

The data required for this component are land area cleared and the carbon content of the biomass cleared. The land area cleared is directly proportional to line length, which would be reported in all project documents. The default right of way required is not specified in the methodologies reviewed, because this can be dependent on infrastructure type. Right of ways for transmission lines can range from 150 to 200 feet for 340–700 kV lines and from 60 to 150 feet for 69–330 kV lines. Applying the biomass density from the IFC CEET requires an unambiguous definition of the land type to be cleared. Because this is not always given in the project documentation, it will be a source of uncertainty unless project proponents can provide additional information.

SF_6 Fugitive Emissions

Sulfur hexafluoride is used in insulation and current interruption applications in both T&D systems (IPCC 2006c). SF_6 is used in gas-insulated switch-

[1] The term *leakage* in the CDM rules refers to emissions impacts outside the defined project boundary.

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. Distribution equipment that is sealed may not emit any SF_6 during use, but transmission equipment often requires periodic refilling and so has higher fugitive emissions during use. The amount of SF_6 emissions during operation and decommissioning is related to the number and type of equipment used, as well as to the maintenance and recycling procedures. This source of emissions could occur in all project categories, depending on the type of equipment installed, refurbished, or maintained.

The magnitude of SF_6 eemissions depends on what equipment is used, how it is maintained, and operational factors. At a national level, countries report SF_6 emissions from the power sector in their national emissions inventories, so this provides one approach for estimating their magnitude.

Review of Existing Methodologies

IPCC Guidelines: The *2006 IPCC Guidelines for National Greenhouse Gas Inventories* provides three approaches to estimating SF_6 fugitive emissions from electrical equipment. The Tier 1 approach, which is the simplest, estimates emissions by multiplying default regional emission factors (provided in the guidelines) by SF_6 consumption by equipment manufacturers and/or the nameplate SF_6 capacity of equipment at each life-cycle stage beyond manufacturing in the country (see table 4.1).

While this is done at a national level in the IPCC Guidelines, the same principles could be applied at a project or utility level. In other words, emissions could be estimated by multiplying nameplate capacity of all equipment in use by the appropriate manufacturing, installation, use, and disposal emission factors.

The Tier 2 approach under the IPCC Guidelines is the same as Tier 1, but the emission factors used must be country specific. In addition, there is a term to include the SF_6 recovery in retirement and disposal. The Tier 3 method is a hybrid of emission factor and mass balance approaches that can be implemented at a facility/utility/project level, and includes separate equations for each stage of the equipment life cycle. Depending on data availability, mass balance approaches may be used for some stages and emission factor approaches may be used for others.

Table 4.1: IPCC Default Emission Factors for T&D Equipment

Type of equipment	Country	Manufacturing % consumed by manufacturers	Use/operation %/year of nameplate capacity losses	Disposal % charge remaining at retirement
Sealed-pressure SF_6-containing equipment	Europe	7	0.2	93
	Japan	29	0.7	95
Closed-pressure SF_6-containing equipment	Europe	8.5	2.6	95
	Japan	29	0.7	95
	United States	n.a.	14 (including installation)	Included in use
Gas-insulated transformers	Japan	29	0.7	95

Source: IPCC 2006c.

Note: n.a. = not applicable.

AM35: The approved CDM baseline methodology AM35 "SF_6 Emissions Reductions in Electrical Grids" provides a detailed utility-level accounting for SF_6 fugitive emissions based on a mass balance approach. For both project and baseline emissions, the mass balance considers decreases in inventory, additions to inventory, subtractions or removals from inventory, retirement of SF_6-containing equipment, and new SF_6-containing equipment purchased. Baseline emissions are from the mass balance of the last three years, while project emissions are from monitored changes in the mass balance in the relevant areas. To apply this approach to a project, the project must have its own dedicated inventory of SF_6 cylinders, and purchases and disbursements of those cylinders must only be for the project.

AM79: While AM79 addresses SF_6 emissions from T&D equipment, it applies only to gas recovery projects implemented at a site for testing gas-insulated electrical equipment. Because it deals only with the recovery and reclamation of gas, it is not relevant for establishing direct nongeneration emissions from a new T&D project.

AM45: Fugitive emissions are the product of the quantity of SF_6 leaks in equipment and the global warming potential of SF_6. The quantity of leaks is determined using information from the equipment manufacturer and/or the quantity of SF_6 injected into the equipment each year during routine maintenance.

Transpower: SF_6 fugitive emissions are calculated using a mass balance approach. In other words, SF_6 purchases less stock changes and disposal/recovery is equal to the amount that must have been emitted into the atmosphere. Transpower's reported SF_6 emissions in 2008/9 were 7,409 tCO_2e. Based on the energy transmitted that year, 38,816 GWh, this would be an emission factor of 0.19 kg CO_2/MWh.

EcoInvent: SF_6 emissions from T&D aare included in the database as part of the life-cycle assessment, based on yearly percentage losses from installed capacity of 1–2 percent, except for the United Kingdom and Ireland, which are both reported to have loss rates of 4 percent (Transpower 2009, table 15.4). Note again that this database covers only European energy systems.

Wartmann and Harnisch (2005): This study on reducing SF_6 emissions reports typical quantities of SF_6 in different equipment types and the electrical capacity of that equipment in Europe (see table 4.2). The study notes that the most important sources of emissions in the future will be sealed-pressure and closed-pressure equipment.

May (2005): See page 28. This is based on European energy systems.

U.S. EPA (2006): This report is mentioned here because it estimated the total SF_6 emissions from the power sector by country and region throughout the world. The estimate includes all T&D components, as well as SF_6 from manufacturing and disposal of T&D equipment. Comparing these data to electricity supply in selected countries, the emission factor for developing countries appears to be 2–3 kg CO_2e/MWh; for industrial countries, it is less than 1 kg CO_2/MWh (see table 4.3). Note that the projections for developing countries are based on electricity supply growth.

Assessment of Available Methodologies

Most of the methodologies reviewed rely on detailed data collection from the project proponent. If a proposed T&D project has a detailed projected SF_6 inventory or list of SF_6-containing equipment along with capacity ratings, estimating fugitive emissions is relatively simple using default fugitive emissions rates from the IPCC, the Wartmann and Harnisch study, or a similar source. The leakage rates for the closed-pressure equipment used in high-voltage lines are reported fairly consistently at 1–3 percent per year across several sources. For the sealed-pressure equipment used at lower voltages, leakage rates would be much lower; thus, these make a much smaller contribution to total sector emissions.

Table 4.2: Characteristics of SF_6-Containing T&D Equipment

Type of equipment	Power rating	SF_6 capacity (kg)	Average annual emissions rate (%)	Share of EU SF_6 emissions (%)
Sealed pressure SF_6-containing equipment	1–52 kV	0.25–10	0.14–0.24	14
Closed pressure SF_6-containing equipment	> 52 kV	3–200	1.8	73
Gas-insulated transfomers	n.a.	n.a.	n.a.	0.2
T&D component manufacturing	>1 kV	<1% mass of product	n.a.	8
High-performance power capacitors	1–5 kV	n.a.	n.a.	5

Source: Wartmann and Harnisch 2005.

Note: High-performance power capacitors are mainly used in trains. Emissions from T&D components will be reduced by over 70 percent in 2010. EU = European Union; n.a. = not applicable.

Table 4.3: SF_6 Fugitive Emissions from the Power Sector in Selected Countries

Country	SF_6 emissions, 2005 ($MtCO_2e$)	Domestic supply of electricity (GWh)	Emission factor (kg CO_2e/MWh)
Brazil	1.37	483,974	2.83
China	6.79	3,268,918	2.08
India	2.00	808,153	2.47
South Africa	0.76	260,580	2.92
Africa total	1.52	621,206	2.45
United Kingdom	0.36	401,358	0.90
Switzerland	0.06	65,888	0.91
Germany	0.24	620,545	0.39

Sources: SF_6 emissions, U.S. EPA 2006; electricity supply, IEA 2007.

If the SF_6 content is not known, or if there is no detailed inventory of what type of equipment will be installed, the alternative is to use sectorwide default factors. These could present some challenges, because they combine higher-emitting, high-voltage equipment with lower-emitting, low-voltage equipment. It would be important to establish whether a particular project was, in fact, installing equipment that contains SF_6, because not all distribution projects will use SF_6-containing equipment. Nevertheless, some default factor may be the only alternative where the project proponents do not have access to detailed data on the SF_6-containing equipment to be installed.

Note that the methodologies that consider SF_6 emissions from new investments implicitly assume that all the SF_6 fugitive emissions along the lines should be allocated to the T&D project. While this makes sense for T&D capacity expansion (new lines), interconnectors for cross-border trade, and electrification, it may not be appropriate for technical loss reduction and increased reliability projects. A technical loss reduction project, for example, is unlikely to replace all of the SF_6-containing equipment in a T&D system. Strictly speaking, only the equipment altered by the project would be part of the physical project boundary, since SF_6 emissions for other equipment would have existed both before and after project implementation.

N_2O Emissions from Corona Discharge

High-voltage transmission lines can create nitrous oxide (N_2O) from an effect called "corona discharge" (see box 4.2).[2] They are only present on the highest voltage lines, and thus would not be applicable to distribution investments or many transmission lines.

Review of Existing Methodologies

May (2005): This study notes that production rates are heavily dependent on weather conditions and are basically higher in case of a high-voltage DC line because of the formation of a space charge cloud. Reported emissions for long-distance transmission lines are less than 1 kg CO_2e/MWh from the actual discharges of N_2O and are not included in the life-cycle analysis results. May also states that, in terms of load losses, "in the annual mean the corona losses amount to approximately 2–3 kW/km for a 400 kV system… [Earlier research] states 1–10 kW/km for a 380 kV system and 2–60 kW/km for a 750 kV system that strongly depends on the respective atmospheric conditions and can be neglected in this order of magnitude."

DeLuchi (1991): DeLuchi includes corona discharge of 3 kg CO_2e/MWh for high-voltage transmission lines, but states that this could be significantly larger. This result is based on a 1984 estimate of total N_2O emissions from the U.S. electric power system in 1980 divided by the total power generation for that year. DeLuchi notes that "fortunately, the most-likely estimate is so small that it does not matter if it is included in the total of greenhouse-gas emissions from electricity generation and use…. However, the maximum estimate of 61 g/kWh is of the same order of magnitude as emissions from the nuclear-fuel cycle and, hence, cannot be ignored."

Box 4.2: The Corona Effect

Corona is a phenomenon associated with all energized transmission lines. Under certain conditions, the localized electric field near an energized conductor can be sufficiently concentrated to produce a tiny electric discharge that can ionize air close to the conductors. This partial discharge of electrical energy is called corona discharge, or corona. Several factors, including conductor voltage, shape, and diameter, and surface irregularities such as scratches, nicks, dust, or water drops, can affect a conductor's electrical surface gradient and its corona performance. Corona is the physical manifestation of energy loss, and can transform discharged energy into very small amounts of sound, radio noise, heat, and chemical reactions of the air components.

Corona is well understood by engineers, and steps to minimize it are a major element in the design of extra high-voltage transmission lines (345–765 kV). Corona is usually not a design issue for power lines rated at 230 kV and lower. Corona activity on electrical conductors surrounded by air can produce very tiny amounts of gaseous effluents: ozone and nitrogen oxides (including N_2O). Gaseous effluents can be produced by corona activity on high-voltage transmission line electrical conductors during rain or fog conditions, and can occur for any configuration or location.

Source: CPUC 2005.

[2] http://en.wikipedia.org/wiki/Corona_discharge; www.archive.org/details/dielectricphenom028893mbp.

EcoInvent: The EcoInvent report (Dones and others 2007) that explains the contents of the database notes that "N_2O emissions of the electricity high-voltage transmission due to corona effect are 5 kg CO_2e/GWh. No country specific data are available." The global warming potential of N_2O is 210, so this is equivalent to 1.05 kg CO_2e/MWh.

While all three of these sources report average corona discharge emissions per megawatt-hour, they also note that these emissions are not directly proportional to electricity transmitted. Corona discharge depends on a variety of site-specific factors, from voltage levels to the specific technical characteristics and shape of components.

Assessment of Available Methodologies

Very limited data are available on corona discharge N_2O emissions levels, or on how these levels are influenced by local conditions. Unlike the other direct nongeneration emissions impacts discussed, there is no linear relationship between N_2O corona emissions and other activity levels or T&D project specifications. Emissions will depend on the exact shapes and configuration of equipment, local weather conditions, and installation and maintenance procedures. The effect is permanent only under extreme design flaws and the right atmospheric conditions, and tends to be momentary (some days during the year) and transitory (a few seconds during over voltage conditions).

Summary of Direct Nongeneration Emissions Impacts

Table 4.4 summarizes which direct nongeneration emissions sources are covered by the different meth-

Table 4.4: Inclusion of Different Emissions Sources in Direct Nongeneration Emissions Methodologies and Case Studies

Source	Embodied emissions	Energy in construction	Land clearing	SF_6	N_2O corona discharge
Typical values (kg CO_2e/MWh)	< 1	Not known	Highly variable but > 10 possible	0.2–3.0	1–3
Studies addressing only direct nongeneration emissions					
IPCC	N	N	N	Y	N
IFC CEET	Y	Y	Y	Y	N
Transpower	N	N	N	Y	N
Aluminium smelter	N	N	N	Y	N
May (2005)	Y	Y	N	N	Y
EcoInvent	?	?	N	Y	Y
DeLuchi (1991)	N	N	N	Y	Y
Studies addressing impacts of generation emissions					
GHG Protocol–Electricity	N	N	N	N	N
AM45/NM0269	N	N	Y	Y	N
AM35	N	N	N	Y	N

Source: Authors' analysis.

Notes: N = not included in direct nongeneration emissions from T&D; Y = included in direct nongeneration emissions from T&D; ? = insufficient detail in report to determine if this source is included.

odologies reviewed. It also includes some of the data on the magnitude of these sources, although there were very few sources for these data. Given that typical oil and coal power stations would have life-cycle emissions of 870–1,335 kg CO_2/MWh (DeLuchi 1991), all the sources discussed here are likely to be less than 1 percent of power generation emissions, although land clearing is highly variable and depends on local land conditions.

Box 4.3 illustrates the direct nongeneration emissions sources discussed in this chapter, using a hypothetical transmission investment.

In terms of project boundary and coverage of sources, the review here suggests several conclusions on direct nongeneration emissions impacts:

- Overall direct nongeneration emissions impacts are likely to be a small share of power generation emissions, with most sources accounting for 1–5 percent of the emissions of a typical fossil fuel–fired power station. The exception could be land clearing, in areas where vegetation is dense, required right of way is large, and lines are long relative to the power transmitted.
- Accurate estimates of most of the direct nongeneration components depend on having detailed activity data about the project which may not be collected in the normal project preparation process. Examples include a construction materials inventory, energy use by construction vehicles, and SF_6 nameplate capacity for all equipment. The feasibility of including these components in the emissions inventory must be assessed on a case-by-case basis. Supplementary data requests to project proponents may be required for estimating these emissions sources.

Box 4.3: Example of Direct Nongeneration Emissions from a Typical Transmission Project

To illustrate the possible magnitude of direct nongeneration emissions from different T&D projects, consider a high-voltage transmission line that is 1,000 km long and has two side-by-side 500 kV lines. Over 20 years, the average flow of electricity is 6,944 GWh/year, for 138,898 GWh in total over the life of the project.

The right of way is 60 m, and the land area cleared is 7,200 ha. If the line went through natural tropical forest, which has the highest biomass density (374 tCO_2/ha above- and below-ground biomass), the total emissions from land clearing would be 2,693,800 tCO_2. This is 19 kg CO_2/MWh.

Assuming that high-voltage equipment accounts for 75 percent of the SF_6 fugitive emissions from T&D, the average emissions of SF_6 for this type of line in Africa would be 1.52 $MtCO_2e$ SF_6 from the African power sector divided by 621,206 GWh electricity supply multiplied by 75 percent, or 1.84 kg CO_2/MWh.

For embodied emissions, taking the line itself as the largest material component, and assuming 1.91 t aluminium and 0.68 t steel/km of line (based on manufacturer specifications), total materials would be 4,575 t aluminium and 1,628 t steel. Using embodied carbon factors of 8.2 tCO_2e/t aluminium and 2.8 tCO_2e/t steel, this is a total of 42,308 tCO_2e, or 0.30 kg CO_2/MWh.

As discussed above, corona discharge is highly uncertain, but could be on the order of 1–3 kg CO_2e/MWh. There are no data available on energy use in construction to estimate that component.

Thus, the maximum total direct nongeneration emissions would be on the order of 25 kg CO_2/MWh. However, if there was no land clearing, or the land was previously cropland or grassland, this figure would fall to 6 kg CO_2e/MWh.

- Corona discharge is more complex, but it is not directly related to traditional T&D project specifications, instead depending on many other local conditions and detailed manufacturing design specifications. Including corona discharge with any level of accuracy would therefore be very difficult.

- Upstream emissions from embodied emissions and energy use in construction are rarely covered by any of the methodologies. They would form part of a more complete life-cycle analysis, which is illustrated in two of the case studies. The feasibility of including this type of analysis in a simple T&D project analysis tool is questionable, given the additional time and cost that would be required to gather the data. This data collection is particularly challenging because loan applications are evaluated before the detailed engineering design studies that might include some of this information have been completed.

- For SF_6, in cases where detailed nameplate capacity data (or at least electrical capacity data) for new equipment are not available, estimating emissions accurately will be much more difficult. National average emission factors would need to be allocated to high-, medium-, and low-voltage systems. In addition, not all projects will include the installation of new SF_6-containing equipment, and projects that do not build new lines (for example, technical loss reduction) will not affect SF_6 emissions for all the existing equipment.

5. Generation Emissions Impacts of T&D Projects

To assess the net impact on emissions from T&D projects, the impacts outside the direct nongeneration emissions project boundary must be assessed. As discussed earlier, the most important net effects are the impacts of T&D projects on the operation of power generation plants, both grid-connected and captive/off-grid. Assessing these effects on power generation requires a net emissions approach because the change in emissions from the power generation system is the difference between the emissions from all power stations after the T&D investment (project scenario) versus what the total emissions from power generation would have been without the T&D investment (baseline scenario). Each of the project categories discussed in chapter 3 will have different impacts on power generation.

As discussed earlier, direct generation effects are where a T&D investment reduces or increases power generation without requiring any other actions outside the physical boundary of the project. In other words, the investor in the T&D project determines the emissions impacts, without the need for action by any other actor. Indirect generation effects, by contrast, require some action outside of the T&D project, either in terms of investment in power generation or changing the operation of power generation plants (grid or off-grid).

All the project categories discussed in this chapter also have direct nongeneration emissions, as illustrated by the net emissions methodologies presented in table 4.4. For example, an electrification project that involves the installation of new SF_6-containing equipment will have direct nongeneration emissions from fugitive emissions, even though the net emissions impacts include increased grid generation and decreased off-grid generation. The focus of this chapter is to understand how T&D projects that fit the principal categories discussed earlier are likely to affect GHG emissions in power generation, and how this has been quantified.

Technical Loss Reduction

The most common positive impact of T&D projects, particularly upgrades or renovations of existing T&D systems, is the reduction in technical losses within the entire electricity grid system (see, for example, World Bank 2004 and 2008b). By upgrading transformers and other substation components, performing additional maintenance, adding reactive power, or other interventions, these project types result in lower technical losses, so that more of the generated power is delivered to the consumer. This is true for both transmission projects and distribution projects that are implemented within existing systems, including a new transmission line added along an existing line.

In a typical economic and financial analysis of a T&D upgrade project, one of the main sources of revenue would be reduced cost of power generation (or purchased power) as a result of lower losses. If electricity sales remain constant after the T&D upgrade and less power generation is required to deliver this electricity, emissions from the operation of power plants on the grid clearly are reduced. If the reduction in technical losses is accompanied by increased sales with the same amount of power generation, however, what does the additional electricity displace?

Given the difficulty of assessing whether increased electricity sales would displace other energy sources, the current practice of T&D project analysis of assuming that loss reductions result in lower power generation is the most appropriate approach. If there is detailed power system modeling in the feasibility study for a T&D project, this analysis would examine how power generation, power flows, losses, and overall system performance would be affected by the investment project. This would also show in more detail how the reduction in losses would affect generation in nonmarginal power plants (for example, large base-load plants). In the absence of a detailed power generation and transmission model, the simplest approach would be to assume that only the set of marginal plants is affected.

A further issue is whether the T&D upgrade could affect construction plans for new power plants by increasing effective supply, and therefore delaying the need for new power generation. While new plants could, in principle, be delayed, this impact would be relatively small because the technical loss improvement generally accounts for only a small percentage of total power generation, so it will not entirely replace new construction in a growing economy.

Review of Existing Methodologies

None of the methodologies reviewed consider any changes in grid plant dispatch or merit order as a result of reduced technical losses. The more recent CDM methodologies include a marginal approach to emissions savings rather than using a reference power plant or average emissions for the entire grid.

***GHG Assessment Handbook*:** Baseline and project electricity generation required to meet demand are calculated from annual power delivered divided by 1 minus technical losses (that is, before and after project implementation). The change in energy generation is divided by the reference power plant's efficiency to obtain fuel savings, which are multiplied by a fuel carbon emission factor to obtain carbon savings. This methodology implicitly assumes that reducing technical losses reduces power generation in the grid, although that is represented by an individual reference plant.

AMS II.A: For retrofit projects, baseline emissions are the product of historical technical losses and the emission factor for the grid. The emission factor for the grid is determined by AMS I.D., which provides two options: (1) weighted average emissions from all grid-connected plants or (2) a "combined margin" approach from the CDM Executive Board (UNFCCC 2009d). Another option for the energy baseline is to determine technical losses of existing equipment based on standards and/or manufacturer ratings rather than actual measurements. For radial networks where no standard is available, other peer-reviewed approaches may be used to estimate baseline technical losses. For greenfield projects where there no T&D equipment is currently in place, the baseline is determined by the standards, manufacturer ratings, or other peer-reviewed methods.

The emissions reductions are limited to the date at which equipment would normally be replaced or retrofitted. Note that this methodology does not apply to introduction of capacitor banks and tap-changing transformers, because their impact on losses is more complex.

AM67: The methodology essentially covers a subset of technical loss reduction projects, where the losses are achieved by installing higher-efficiency transformers in the existing distribution system. Baseline emissions are the product of "no-load" technical loss rates of transformers, annual operating hours, and the combined margin grid emission factor, as presented in UNFCCC (2009d). No-load losses are either

- the *minimum* of (1) measured losses in the top 20 percent of transformers and (2) the loss rate specified in national regulations for transformers, or
- loss rates specified in national regulations, without reference to measured losses.

Project emissions are calculated similarly but using measured no-load loss rates of transformers installed by the project. This methodology does not apply to load losses.[1]

Assessment of Available Methodologies

The available methodologies are similar to the standard economic analysis used for World Bank projects, in that they analyze technical loss reduction projects as reduced power generation. The reduction in generation is the difference in technical loss rates before and after the project multiplied by the total electricity delivered (although it may be specified directly in some project documents rather than as a percentage of the total). The early methodology used a weighted average emission factor, but the newer CDM methodologies consider marginal changes and thus use a marginal grid emission factor.

Increased Reliability

Not only do T&D upgrades and rehabilitation reduce technical losses, but they also increase the reliability of the T&D system so that there are fewer power outages for consumers (see, for example, World Bank 2004 and 2008b). These outages are costly for consumers not only because they may lose production (a factory that loses power) or inventory (cold storage or supermarket), but also because they may purchase backup power supplies (for example, diesel generators) to protect against outages. Although these backup power supplies may only operate during power outages, they must be maintained year round.

In a typical financial and economic analysis of a T&D upgrade, reduced outages are treated as an increase in sales. In other words, more electricity is delivered to the consumer after the project is implemented; therefore, more electricity is generated as well. This is also because grid power generation would normally be reduced during an outage period. The net impact of reduced power outages on GHG emissions is therefore the difference between the increased operation of connected power plants as a result of the T&D investment and the reduced use of backup power if any form of backup power is used.

The critical question here is what sources of power, if any, are displaced when outages decline—in other words, what did consumers do during power outages before the T&D reliability project was implemented? If consumers used captive power for backup power during outages, these generation sources will be used less when outages decline. If the emission factor of the captive power is higher than for grid power (which it usually is), net emissions will decline. If consumers do not have backup power, however, and they simply use less electricity when there are power outages, net emissions would increase as outages decline. The concept of suppressed demand is useful here (Winkler and Thorne 2002). Because there is a demand for this service that is constrained by technical factors (for example, unreliable power supply), the emissions from the additional electricity supplied when outages decline could be compared to the alternatives for supplying that power, even if the consumers do not actually own a backup power supply. This is not standard practice in World Bank economic analysis of projects, which would compare the "with project" scenario to the current situation, even if the energy service levels were not the same in the two scenarios.

Review of Existing Methodologies

None of the GHG methodologies reviewed explicitly addresses the GHG impacts of increased reliability and reduced outages.

Assessment of Available Methodologies

The absence of available methodologies could be a result of the challenges of estimating what on-site backup power source, if any, is displaced by the increased sales of electricity to consumers and how to address the issue of suppressed demand.

[1] Load losses or coil losses are those losses caused by resistance in the electrical winding of the transformer; they include eddy current losses in the primary and secondary conductors of the transformer. Load losses of the transformer vary with load; therefore, crediting such reduction would require continuous monitoring of the load on the project activity transformer.

Distribution Capacity Expansion

Distribution projects that significantly increase the capacity of the power distribution system bring additional power generation to new or existing consumers. The rationale for increasing distribution capacity to existing consumers would be that their demand for power has increased, and there is either surplus power capacity available elsewhere in the grid or new generation coming online that must be brought to these consumers. In other words, over the long term, distribution capacity expansion would almost always be accompanied by power generation capacity expansion.

Unlike technical loss reduction, distribution capacity expansion could contribute to increased emissions from grid generation when compared to the baseline scenario. The project emissions for the type of project would be based on the additional electricity being generated for distribution, which could be from fossil fuel–fired power plants. Of course, if the additional power generation is from renewable energy, project emissions would be much smaller, or even nonexistent.

Baseline emissions depend on whether the additional power supplied by the grid displaces other off-grid alternatives for power supply. The additional power meets additional demand. How would this demand have been met if distribution capacity expansion had not been implemented? Would consumers have used an alternative source of power, such as captive power or isolated grids? The reduction of captive or local grid power use must also be considered in the analysis of impacts on emissions from power generation. (This is why figure 2.4 includes captive power as well as grid power within the boundary of analysis.) There will also be situations where end-use demand would not exist and the power would not have been supplied if the project were not implemented. An example would be a new factory that requires significantly more power than the local grid can supply. Without an upgrade of T&D infrastructure, this new facility would not be built, and so the baseline "without project" electricity use is zero. Another possibility is that the alternative energy source has a much higher unit cost, so consumers cannot afford the alternative even though they can afford to use grid electricity.

Review of Existing Methodologies

None of the methodologies reviewed provide tools or approaches to estimate the net impact on power generation of increased distribution capacity.

Assessment of Available Methodologies

The absence of available methodologies means that an approach for this project type must draw on experience with other project types, such as electrification and increased reliability.

Electrification

Electrification projects include additional distribution (and, potentially, transmission) investments that connect new consumers to the electricity grid. These may be consumers within existing electrified areas that did not have access or entire communities that did not have grid electricity access. In either case, the electrification investment potentially displaces existing or future energy sources with grid electricity. There must be additional power generation available to meet this increased demand, so generation from the grid-connected power plants must increase (either through higher capacity utilization or new plant construction).

In contrast to distribution capacity expansion to serve existing consumers, however, electrification may displace energy sources other than electricity. In rural electrification, for example, new electricity supply to households could displace other energy sources that were used for heating, lighting, and cooking.

For new consumers connected within an electrified area, the alternative could include captive power generation or a stand-alone minigrid. This could also be true for industrial and commercial consumers in an entirely new electrified community.

For households in a newly electrified community, the baseline scenario could be a combination of off-grid power sources and nonelectrical energy sources. Alternatives to grid electricity will be used by consumers as long as the financial resources are available and they are willing to pay the price of the alternative.

Review of Existing Methodologies

AM45: This methodology covers a subset of electrification projects that connect small isolated grids to the interconnected national grid system. The methodology applies where there was an existing isolated grid supplying a group of consumers, and the fossil fuel–fired power plants in the isolated grid will no longer be operated once the area is connected to the national grid (renewable power generation in the isolated system must continue to operate). Baseline emissions are initially the product of the weighted average emission factor of the isolated grid and the amount of power supplied from the national grid after interconnection. To take into consideration the normal replacement of generation equipment in the isolated system, the baseline emission factor declines over time toward the emission factor for the best available technology for isolated grid supply. Project emissions are the product of electricity supplied from the interconnected grid to the previously isolated area (adjusted for incremental technical losses) multiplied by the combined margin emission factor, calculated from UNFCCC (2009d).

Assessment of Available Methodologies

AM45 provides a comprehensive and accurate approach for one type of electrification project, namely the displacement of isolated grid systems through connection to an integrated national grid. Given the challenges of estimating the displacement of nonelectric energy sources—particularly in a rural electrification program—moving beyond this type of project will require substantial methodological work. The World Bank has recently commissioned such work on a more comprehensive rural electrification methodology. That study will review the literature on rural electrification to determine whether there are consistent patterns of baseline energy use and shifts in patterns post-electrification across different countries and regions. It will also develop a new CDM methodology to address a subset of rural electrification projects—the first such effort to address fuel displacement in the context of carbon financing or carbon accounting.

Transmission Capacity Expansion

Investments in new transmission capacity within a country may have several different purposes:

- To increase the capacity of an existing transmission corridor by adding transmission lines
- To connect a new power station that is far from the major demand centers to a grid that serves those demand centers
- To create new links between subnational grids that had not been previously connected

The final case is similar to new interconnectors between national grids, which is addressed in the next section, "Cross-Border Trade," along with international interconnectors.

For the first two cases, the capacity expansion project is bringing additional power generation through the transmission network, because this would be the reason new lines were required. This additional power generation may or may not be part of the same investment project as the new transmission line. Thus, the additional generation, and emissions from that generation, should be considered in assessing the net impact on generation emissions. The project emissions could be based on the entire grid that transmits more power or on a single new plant, if the capacity expansion is to deliver that new plant's production.

As with distribution capacity expansion and increased reliability, the selection of an appropriate baseline scenario depends on whether consumers would have used an alternative power source if the power generation and transmission capacity was not built. The alternative to expanding the transmission system could be to generate power for end users on site or through a local minigrid, or possibly to build a higher-cost power plant closer to the source of demand. This holds true regardless of whether the consumers are current grid customers or are off the grid. Where there are existing sources of nongrid power being used in the areas served by a transmission system expansion, they can be used to develop the baseline scenario. On the other hand, if consumers do not have the technical or financial means to generate their own power, which may be much more expensive per unit of energy, they will not use additional power at all. Thus, the baseline is no additional power production and consumption by those consumers.

An important example of how a transmission line would affect generation emissions is the link between transmission capacity and large-scale renewable power generation. Recent analysis on large-scale roll-out of wind power has pointed out that a lack of transmission capacity is often a major constraint on construction of renewable power plants. Where renewable power sources are far from demand centers, and where current transmission capacity is already constrained, transmission investments are an important component in achieving emissions reductions from renewable power generation investments. In this case, the increased grid generation in the project scenario does not lead to an increase in emissions; this may displace significant fossil fuel alternatives in the baseline.

This example shows why, for both distribution and transmission capacity expansion projects, there is the potential for double counting between T&D projects and power generation projects (see "Double Counting," page 19). The net impact of the T&D project on power generation would be the same as the net impact calculated from the new generation plant. Thus, it would not be accurate to add the net impacts of these projects together, since they overlap.

One final impact that should be considered is how increased transmission capacity along an existing corridor affects technical losses over the entire corridor. If the installation of a newer, more advanced additional transmission line means that some of the power from the existing lines now flows through the new line, technical losses for the entire corridor could be reduced. Projecting this impact would require a relatively sophisticated load-flow modeling analysis as part of the project proposal. If such impacts and modeling exist, their GHG impacts can be analyzed as in any other loss reduction project.

Review of Existing Methodologies

As with increased distribution capacity, none of the methodologies reviewed contain tools for estimating the impact of increased transmission capacity on power generation beyond the impacts of reduced losses and increased reliability.

Assessment of Available Methodologies

The absence of available methodologies means that an approach for this project type must draw on experience with other project types.

Cross-Border Trade

One of the most important types of T&D investments undertaken by the World Bank is new interconnectors between separate existing grids, particularly connections between the grids of neighboring countries (see, for example, World Bank 2003 and 2007). By connecting a national grid that has surplus power generation capacity with one that is capacity constrained, this new interconnector can provide more electricity services to the region without increased investment in power generation. If the exporting grid is a largely hydropower grid, and the importing grid is largely fossil fuel–based generation, this trade can reduce GHG emissions while increasing electricity supply to the connected system (Econ Analysis 2006) (see box 5.1).

What makes evaluating the impact of a new interconnector challenging is the fact that the connection

Box 5.1: Cross-Border Trade and GHG Emissions Example: Cambodia-Vietnam

The Cambodia Rural Electrification and Transmission Project—which formed the basis of a proposed CDM baseline methodology (NM0269)—includes the introduction of a 220 kV interconnection between Cambodia and Vietnam. This interconnection would facilitate the import of significant amounts of electricity (up to 200 MW capacity, 1,500 GWh per year) from Vietnam, which has larger, more efficient, and lower-emission-factor power plants, comprising a mix of hydropower (36 percent), gas-fueled, and coal-fired generation plants. This trade would meet Cambodia's demand growth, which would otherwise have to be met by smaller, less efficient, higher-emission-factor sources, mainly diesel or heavy fuel oil–fired diesel engines and steam turbine–driven generators.

The estimated GHG emissions impact was based on the difference in the grid emission factors of the two countries and the incremental amount of electricity imported into Cambodia. The emission factor for Vietnam is calculated as the average of the ex ante simple operating margin and the ex ante build margin. The emission factor for Cambodia is calculated as the average of the ex post simple operating margin and the ex post build margin. These emission factors are defined in the "Tool to Calculate the Emission Factor for an Electricity System" approved by the CDM Executive Board. Fugitive emissions from SF_6 from new T&D line components were also considered (although these are negligible, at only 230 tCO_2/year).

The calculated combined margin emission factors for Cambodia and Vietnam are 0.741 tCO_2/MWh and 0.678 tCO_2/MWh, respectively. The incremental traded electricity is projected to increase from 625 GWh in year 1 to 1,489 GWh in year 10. The emissions reductions over 10 years are therefore 536,158 tCO_2.

Source: UNFCCC 2008a.

and free flow of power between the two previously separate grids may change the dispatch or merit order of many of the plants on both grids. Thus, the combined grid may not operate simply as the sum of the two grids (Econ Analysis 2006). A dispatch model may be able to predict the operation of this new system, but creating a simple ex ante estimate in the absence of such models may be difficult. Assumptions about demand projections and generator unit parameters can be used for a simplified estimate, but a dispatch model may more accurately reflect how an interconnection will affect generation emissions, particularly if multiple dispatch rules could be considered. Dispatch rules can significantly affect emissions from the power sector. Traditionally, least-cost (or price) rules are used to dispatch power generation. In some power systems, dispatch rules consider some constraints regarding local pollutants, such as oxides of nitrogen and sulfur. Dispatch models can also consider rules that limit or minimize GHG emissions. Although these types of rules could be readily used to control GHG emissions, their application is limited given their implications for the cost of power generation.

In terms of the impact of interconnectors on the dispatch of power generation, one issue is which direction the electricity flows, because emissions will only be reduced if power flows from the less carbon-intensive grid to the more carbon-intensive grid. While power purchase contracts between the utilities operating the grids will set the basic parameters for trade, there is no guarantee that the flow is always in one direction. High-voltage DC lines will be easier to monitor for flow direction and current, but even in these systems power can potentially flow in either direction—the utilities may want this to be so for when water supplies in the hydro-dominated grid are low.[2]

A second issue is whether the interconnected grid has a combined or integrated dispatch center. If the two grids continue to operate largely independently, it may be appropriate to simply consider the transmission line as a single new low-carbon power plant on the importing grid, and evaluate the emissions impacts similarly to those of a new renewable power plant. However, if the connected grids operate as a single grid with a single or coordinated dispatch center, or with extensive communication between the dispatch centers, this approximation will be less likely to reflect the actual impact of the new line on power generation in both grids. There may be other unintended effects, based on the relative costs of generation across the grids, the reliability of the generation sources, and the mix of base load versus load following capacity in each grid. Ideally, the emissions impacts should be evaluated based on ex ante and ex post monitoring of generation in both grids.

A third issue is which plants are used for the exported power and which are displaced in the imported grid. While using average emission factors for both grids is the simplest way to analyze the change in emissions from increased trade, this may not reflect actual grid operation. Power plants are generally dispatched on merit order, which reflects the marginal cost of power generation. In other words, the best proxy for power generation displaced by imports would be the last plants dispatched—those that have the highest marginal costs. These are generally fossil fuel plants, although the highest-cost plants are not necessarily the most carbon intensive. For example, a gas-fired plant might have a higher marginal cost, but lower emission factors than a coal plant. For exports, the power would come from the power plants that were underutilized prior to the construction of the interconnector or from plants built explicitly for export capacity. The underutilized plants could be higher marginal-cost plants, although hydropower capacity may be underutilized because of the seasonality of flows or the distance from demand centers, even though this is generally a lower marginal-cost power plant. New plants for export could include large hydropower plants, in which case the emission factors for these new plants should be used for project emissions rather than the overall grid.

Aside from impacts on the operation of existing plants, another major issue is whether the new interconnector affects the construction of new plants in each country. The impact of cross-border trade on plant construction is difficult to assess, because many countries or utilities have required reserve margins and may choose to consider only domestic supply as secure. Because of political concerns about security of supply, governments and utilities may not necessarily delay the construction of domestic power generation capacity even if additional imported power is available (Econ Analysis 2006). In fact, cross-border imports may be seen as a way to meet demand temporarily until domestic supply construction can catch up with demand.

Clearly, if a country already imports most of its electricity from a neighboring country, or if the project activity will supply a significant portion of consumption in the neighboring country, cross-border imports have an impact on domestic capacity expansion. The emission factor for surplus power supplied by the exporting countries could be based on the current marginal plants in the exporting country, while the emission factor for additional power supplied (which requires the construction of new generation) should consider the new generation in the exporting grid. This is similar to the distinction made between trading surplus versus firm power, where the cost of surplus power is the marginal cost of existing plants, and the cost of firm power is the full cost of new power generation in the exporting system.

[2] See the discussion by the Methodologies Panel on NM0269 (UNFCCC 2009e).

Review of Existing Methodologies

NM0272 and NM0269: Both NM0272 and NM0269 were proposed as methodologies to estimate the net impact of a transmission interconnector between two national grids and the increased trade this would allow. After several rounds of discussion between the project proponents and the CDM Methodologies Panel on a draft approved methodology incorporating both proposals, these methodologies were rejected. The major provisions of these methodologies are discussed here, as well as the reasons why they were not accepted in the CDM.

Both methodologies begin from the premise that when a transmission line connects a high-emission-factor grid with a low-emission-factor grid (typically hydropower dominated), power exports from the low-emission-factor grid will displace high-emission-factor power generation in the importing grid. In other words, the transmission line is similar to a new power generation plant on the importing grid, with an emission factor reflecting the entire grid of the exporting country. Baseline emissions are therefore the product of the importing grid emission factor and the amount of electricity imported. Project emissions are the product of the exporting grid emissions and the amount of electricity exported, adjusted for technical losses if necessary. The methodologies only consider net increases in trade, to account for situations where there was some connectivity prior to the project.

The two main issues raised during the subsequent revisions and discussions of these proposals are how to deal with a possible two-way flow of power and which emission factors to use for each grid. On the issue of flow, even if the exporting country currently has surplus power, there is still the possibility that a hydro-dominated exporter might have to import power if water supplies were very low. This reverse flow of power through transmission therefore displaces low-emission-factor electricity with high-emission-factor electricity. To reduce this likelihood, the methodology proponents included various applicability conditions (that is, whether there is surplus capacity in an exporting grid, or whether the importing country is historically a net importer), and limited the emissions reductions to net increases in traded electricity. This was accepted in the draft methodology proposed by the Methodologies Panel.

The choice of emission factors for the two grids has a critical impact on net emissions reductions. Originally, NM0269 proposed using the following emission factors for connected national grids.

- **Baseline emissions:** The combined margin emission factor for the importing electricity system is calculated using the latest version of the "Tool to Calculate the Emission Factor for an Electricity System" (UNFCCC 2009e) with the following conditions:
  - The operating margin is calculated as the simple operating margin, using ex post data.
  - The build margin is calculated using ex post data, updated annually (Option 2).
  - The combined margin uses 50-50 weightings of the operating and build margins.
- **Project emissions:** The emission factor for the exporting electricity system is calculated using the combined margin emission factor ($EF_{grid,CM}$) as in UNFCCC (2009d) with the following conditions:
  - The operating margin is calculated as the simple operating margin, using three years of historical data or the simple adjusted operating margin, if low-cost or must-run resources are more than 50 percent of total grid generation.
  - The build margin is calculated using ex ante data (Option 1).
  - The combined margin uses 50-50 weightings of the operating and build margins.

The approach in NM0272 was somewhat different. For baseline emissions, the emission factor was the combined margin (50-50 weightings) for the importing grid, where the operating margin was calculated using current year dispatch data analysis, and the project proponents choose the approach for the build margin. For project emissions, the emission factor is the dispatch data operating margin for the exporting grid; no build margin is included.

The draft approved methodology prepared by the Methodologies Panel modified the emission factors as follows:

- **Baseline emissions:** The operating margin is calculated from either: (Option 1) dispatch data analysis or (Option 2) other recognized operating margin approaches. The use of the build margin was implicitly included, although the approach was not specified. The proposal specifies that the minimum of the operating or build margin must be used as the emission factor for the grid, rather than a weighted average.
- **Project emissions**: The operating margin is calculated from either: (Option 1) dispatch data analysis or (Option 2) ex post calculations that rank the plants of the operating margin by decreasing emission factor and use the top-emitting ones to cover the annual net demand transferred over the new transmission lines. The build margin approach was not discussed, but the proposal specifies that the maximum of the operating or build margin must be used as the emission factor for the grid, rather than a weighted average.

Assessment of Available Methodologies

The key differences in the draft approved methodology and the NM0269 and NM0272 proposals are the choices of emission factors for the importing and exporting grids. The implications of using the highest-emission-factor plants instead of a simple operating margin or dispatch data are significant. The example in box 5.2 shows the calculation of the emission factors using the different approaches, in a system where the exporting country is 90 percent hydropower and the importing country is 90 percent fossil fuel. Using the draft approved methodology approach of the maximum of the operating or build margin for the exporting system and the minimum of the operating or build margin for the importing country, there would be no emissions reductions credited for this trade because the emission factor for the exporting grid is higher than for the importing grid.

Because the draft approved methodology was never submitted to the CDM Executive Board, and both of the proposed methodologies were rejected, this discussion is currently stalled within the CDM.

Summary of Impacts on Power Generation: Direct and Indirect

This discussion and review of available methodologies has several conclusions:

- For the impacts of T&D projects on power generation, some of the project categories have very limited coverage. There are no methodologies for impacts of distribution and transmission capacity expansion. Within the wide scope of electrification projects, only the impact of grid electricity displacing isolated fossil fuel grids is covered. None of the proposed methodologies for cross-border trade has yet to gain acceptance in the CDM or other GHG accounting system.
- Some of the CDM methodologies, such as AM67, have relatively narrow applicability conditions, so they cannot cover the wider range of T&D projects within the World Bank portfolio.
- The CDM methodologies rely heavily on monitored data, since they must have a higher level of credibility and track actual project performance. This differs from the objective of this study, which focuses on relatively simple ex ante approaches to estimating GHG impacts.
- There is no methodology that addresses all of the multiple impacts of T&D investments (for example, technical loss reduction, increased capacity, and primary effects of land clearing and SF_6 emissions).

Box 5.2: Illustration of Sample Grid Emission Factor Calculations in the Draft Approved Methodology from NM0269/NM0272

The following calculations illustrate how the choice of grid emission factors (EFs) for exporting and importing grids can dramatically affect the emissions reductions credited to an interconnector project. If the proposal from the draft approved methodology prepared by the CDM Methodologies Panel had been accepted, there would be no emissions reductions credited to electricity trade—even in this example where the exporting country is 90 percent hydropower and the importing country is 90 percent fossil fuel. This is because the EF for the most carbon-intensive plant in the exporting grid is higher than the EF for the importing grid.

Exporting Country

Plant	Size (MW)	Load factor (%)	Power generation (MWh)	Fuel	Date built	EF tCO_2/MWh	OM	BM
1	100	80	700,880	Hydro	1970	0	k	N
2	100	80	700,880	Hydro	1990	0	k	N
3	100	80	700,880	Hydro	1990	0	k	N
4	100	80	700,880	Hydro	1990	0	k	N
5	100	80	700,880	Hydro	1991	0	k	Y
6	100	80	700,880	Hydro	1995	0	k	Y
7	100	70	613,270	Hydro	1960	0	k	N
8	100	70	613,270	Hydro	1990	0	k	N
9	100	60	525,660	Hydro	1990	0	k	N
10	100	50	438,050	Coal	1980	1.1	j	N
Total	**1,000**		**6,395,530**					

Estimated lambda	0.50	Assuming fossil plant only runs 50% of year
Operating margin (OM) highest EF plant	1.10	Suggested in draft approved methodology
OM simple adjusted	0.55	Suggested in NM0269
Build margin (BM)	–	
EF (maximum BM & OM)	**0.55**	Using simple adjusted OM
EF (maximum BM & OM)	**1.10**	Using top EF plant for OM
Combined margin (CM)	**0.28**	Using simple adjusted OM and 50-50 OM/BM weighting

Importing Country

Plant	Size (MW)	Load factor (%)	Power generation (MWh)	Fuel	Date built	EF tCO_2/MWh	OM	BM
1	100	80	700,880	Coal	1970	1.1	Y	N
2	100	80	700,880	Coal	1990	1.1	Y	N
3	100	80	700,880	Coal	1990	1.1	Y	N
4	100	80	700,880	Coal	1990	1.1	Y	N
5	100	80	700,880	Oil	1991	0.9	Y	N
6	100	80	700,880	Oil	1995	0.9	Y	Y
7	100	70	613,270	Oil	1960	1.0	Y	N
8	100	70	613,270	Oil	1990	0.9	Y	N
9	100	60	525,660	Oil	1990	1.0	Y	N
10	100	50	438,050	Hydro	1999	0.0	N	Y
Total	**1,000**		**6,395,530**					

OM simple	1.01	
BM	0.55	
EF (minimum BM & OM)	**0.55**	As proposed in draft approved methodology
CM	**0.78**	Using 50-50 OM/BM weighting

Source: World Bank calculations.

The relationship between T&D project categories and possible impacts on power generation is summarized in table 5.1. In this table, "Y" does not mean that the project definitely has an impact, but that many projects within that category are likely to have that impact, which should be evaluated on a project-by-project basis.

Table 5.2 summarizes conceptually the baseline and project scenarios for determining the impact on power generation of each project category. As discussed earlier, within the categories of T&D capacity expansion, there are some additional distinctions by project types, which are thus presented in more than one category.

Box 5.3 illustrates the various impacts that have been discussed in this chapter, using the hypothetical project originally presented in box 4.1.

Table 5.1: Possible Impacts of Different T&D Project Categories on Power Generation

Project category	Possible impacts on power generation				
	Reduce marginal power generation	Increase marginal power generation	Displace alternative power	Displace other energy	Change power build plan
Direct generation effects					
Technical loss reduction	Y	N	N	N	N
Indirect generation effects					
Increased reliability	N	Y	Y	N	N
Distribution capacity expansion	N	Y	Y	N	N
Electrification[a]	N	Y	Y	Y	N
Transmission capacity expansion—new lines within a grid	N	Y	Y	N	Y?
Transmission capacity expansion—connect grids	Y (one grid)	Y (one grid)	N	N	Y
Cross-border trade	Y (one grid)	Y (one grid)	N	N	Y

Source: Authors' analysis.

Note: Y = this project type may have this type of impact; N = this project type would not have this type of impact.

a Electrification includes distribution capacity expansion that is directed at new customers.

Table 5.2: Baseline and Project Scenarios for Impacts of T&D Investments on Power Generation

Project category	Project scenario	Baseline scenario
	Direct generation effects	
Technical loss reduction	Generated electricity lost through technical losses after project implementation	Generated electricity lost through technical losses prior to project
	Indirect generation effects	
Increased reliability	Additional power generation during longer supply hours	Power source used during power outages or no emissions if alternative is not available
Distribution capacity expansion	Additional grid generation delivered to consumers, or generation from new plant	Alternative power source displaced by additional grid power or no emissions if alternative not available
Electrification[a]	Additional grid generation delivered to consumers, or generation from new plant	Alternative power sources displaced by additional grid power or no emissions if alternative not available
Transmission capacity expansion—new lines within grid	Additional grid generation delivered to consumers, or generation from new plant	Alternative power sources displaced by additional grid power or no emissions if alternative not available
Transmission capacity expansion—connect grids	Marginal or surplus power generation in exporting grid, or generation from new plants built for export	Marginal power generation in importing grid
Cross-border trade	Marginal or surplus power generation in exporting country, or generation from new plants built for export	Marginal power generation in importing country

Source: Authors' analysis.

a Electrification includes distribution capacity expansion that is directed at new customers

Box 5.3: Example of Impact of Generation Emissions from a Typical Transmission Project

For the same transmission line presented in box 4.1, consider the possible impacts on power generation emissions. If technical losses on this line were 15 percent, the project reduced these losses to 10 percent, and the grid had a relatively carbon-intensive emission factor of 700 kg CO_2/MWh, the loss reduction project would save 4,861,435 tCO_2 over the project life. This is equivalent to 35 kg CO_2/MWh.

If, on the other hand, the project was a capacity expansion project that did not have any alternative baseline supply of power (for example, no additional power would have been used if this capacity expansion was not built), transmitting an additional 138,898 GWh over 20 years leads to an increase of generation emissions of 97,228,702 tCO_2 (700 kg CO_2/MWh). If this new capacity displaced isolated diesel generators with an emission factor of 800 kg CO_2/MWh, emissions would be reduced by 13,889,814 tCO_2 or 100 kg CO_2/MWh.

If the transmission line was an interconnector that connected two grids, and the marginal emission factors of the exporting and importing grids were 100 kg CO_2/MWh and 750 kg CO_2/MWh, respectively, generation emissions would be reduced by 90,283,795 tCO_2 or 650 kg CO_2/MWh.

If the transmission line was part of an electrification project that brought power from a new hydropower station (emission factor of 0 kg CO_2/MWh) and displaced small diesel generators (emission factor of 1,200 kg CO_2/MWh), emissions would be reduced by 166,677,775 tCO_2. If the grid supplying the new power was coal dominated (emission factor of 1,000 kg CO_2/MWh), emissions reductions would only be 27,779,629 tCO_2.

For all these cases, it is clear that the impact on generation emissions is likely to be much larger than the direct nongeneration emissions.

6. Recommended Approach

In considering which elements of the available methodologies to adapt for estimating net GHG impacts of T&D projects, one of the key issues is **feasibility**. Many of these projects will not have extensive data available (either historic or projected) on power flows and individual plant-level power generation; any new methodology must acknowledge this and not require extensive additional data collection. The teams conducting the economic, financial, and technical analyses of new World Bank projects should be able to apply the tools fairly easily. The approaches should be standardized as much as possible, so they are easy to apply across different countries.

Credibility is also important, so if the new methodology is going to deviate from the practice of other carbon methodologies, there should be a clear justification for this, and the risk of overestimating net impacts should be relatively low. This measure will also help with **harmonization** of the new methodology with existing methodological approaches. Credibility also includes addressing the multiple impacts of T&D projects to ensure that the emissions impact analysis presents a comprehensive picture. Any risk of double counting should be clearly highlighted (see "Double Counting," page 19). Addressing the multiple impacts of T&D investments will require a modular approach to the analysis, which is discussed in more detail below. Comprehensive subsectoral coverage in this methodology, composed of a number of modules, will also support the understanding of sectoral approaches to estimating GHG emissions reductions.

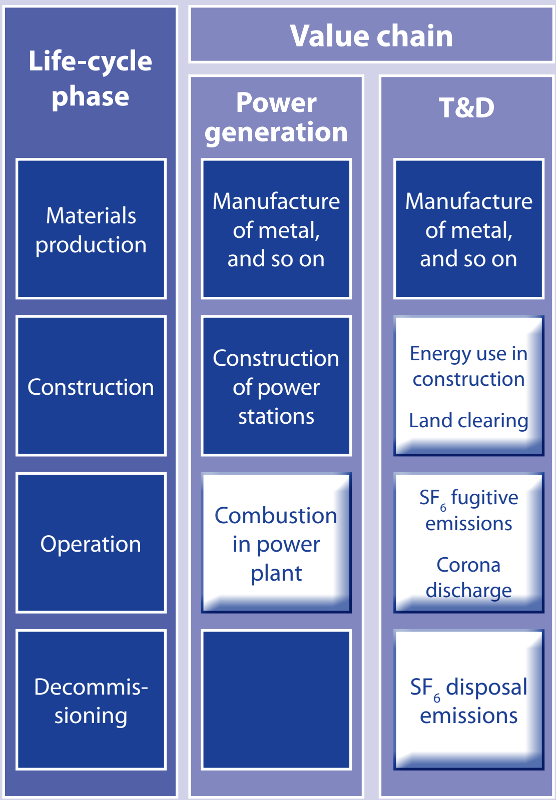
In addition to the general principles for GHG accounting described in chapter 2, the analysis of existing methodologies and the objectives of this study point to several key features that should be considered for net emissions accounting methodologies:

- **Modularity:** Because a given investment may have multiple objectives and multiple components, emissions accounting methodologies should be modular. Each module should address a specific impact, so these can be combined to assess a wide range of T&D investments.
- **Tiered:** In the IPCC "tiered" approach, more detailed methodologies are used where more detailed data are available. Similarly, the emissions accounting methodologies should include some default parameters, but require that more detailed approaches be used where the data are available. An example would be dispatch data or detailed system flow modeling, which should be used whenever available, but which may not be available for all projects. Simplified approaches are also required for the latter cases.
- **Ex ante:** As specified in the terms of reference for this study, the net emissions impact should be assessed ex ante, and not require monitoring, so historical data should be used for all calculations.

Recommended Project Boundary

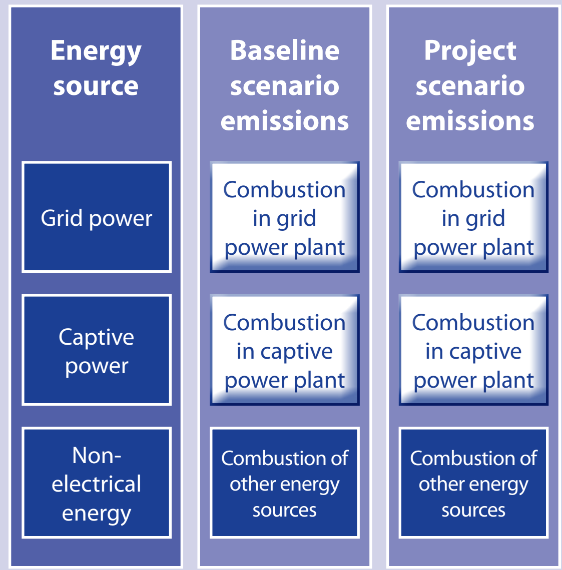
Based on the analysis of existing methodologies and case studies examined in chapter 4, the recommended project boundary is shown in figure 6.1. Project characteristics may mean that some of these emissions sources may be zero, but they must still be explicitly assessed. Corona discharge is excluded for the reasons explained under "N2O Emissions from

Figure 6.1: Recommended Project Boundary for T&D Projects



Source: Authors' analysis.

Figure 6.2: Recommended Baseline and Project Emissions Sources for Assessing the Impacts of Emissions on Generation



Source: Authors' analysis.

Corona Discharge" on page 34: namely, that there are no methodologies for translating the numerous site-specific drivers of this emissions source into an accurate estimate. The inclusion of generation emissions in the project boundary is also indicated. In keeping with the review of other methodologies presented in chapter 5, fuel supply emissions and emissions related to consumption of electricity are not included.

Since many T&D projects may displace captive power, this is included in figure 6.2. Emissions from nonelectric energy sources are not included, because they only apply to electrification projects, and none of the methodologies reviewed provide any guidance or data on this impact.

Fuel supply stages are excluded based on their very small contribution to life-cycle emissions. For example, for a coal-fired power plant, the emissions from upstream fuel production (for example, methane emissions from, and energy use in, coal mining) could be between 0.4 percent and 11 percent, depending on the origin of the coal.[1] Natural gas upstream emissions are estimated at 0.4 percent of combustion emissions, and oil-fired power would be similar.[2] Given that all the grid electricity CDM methodologies consider only combustion emissions at the power plant, and not upstream, this study proposes to limit the project boundary for assessing net impacts to only the power generation stage. Because the electricity supplied by a new T&D project could displace nongrid sources of energy (for example, captive or backup power), baseline

[1] Based on a combustion emission factor for other bituminous coal of 0.0946 tCO_2/gigajoule, net calorific value of 25.8 gigajoule/t (IPCC 2006b), and upstream emissions of 0.0134 t methane/t coal and 0.008 t methane/t coal for underground and open-cast mining, respectively (UNFCCC 2009b).

[2] Based on combustion emissions of 0.0561 tCO_2/gigajoule gas (IPCC 2006b) and upstream emissions of 0.296 kg methane/gigajoule gas (also from ACM9).

and project emissions must be assessed for all these sources. The importance of combustion emissions to power sector emissions and global energy sector emissions makes it more meaningful to focus on these upstream impacts rather than the downstream impacts from energy consumption.

Direct and indirect emissions impacts are estimated for the same project life used in technical and economic appraisal of a Bank-funded project to ensure the consistency and feasibility of the proposed approach.

Step 1. Determine Which Direct Nongeneration Emissions Will Be Included

Table 6.1 presents the questions to be asked, through review of the project preparation documentation, to determine which modules for direct nongeneration impacts will be included in the project assessment. The modules are presented in detail in the next section. Following is further explication of the questions.

- **Are data available on materials consumption by the T&D project and on the origin of those materials?** This module will only be applied for projects where a detailed materials inventory is available during project preparation or can be obtained from project proponents. This inventory should include the quantities of various metals, concrete, wood, and so on, that will be used for the project. The country of origin for these materials must be known so as to determine whether the available databases of embodied emissions of construction materials are applicable.
- **Are data available on energy consumption during the construction phase of the T&D project?** This module will only be applied to projects for which there are data on fuel consumption by construction vehicles or other energy sources used during the construction phase of the project.
- **Does the project involve clearing any land?** Projects that only upgrade or rehabilitate existing lines and installations will not have an impact on land use, nor would projects that construct lines along existing roads or rail lines. Only in cases where there is clearing of land specifically for new lines or equipment should this module be applied.
- **Does the project include new lines or capacity expansion that includes new SF_6-containing equipment?** Projects that do not install entirely new lines or substations are unlikely to cause a net increase in SF_6 emissions. Thus, this module should only be applied to projects involving capacity expansion, electrification, and cross-

Table 6.1: Questions to Determine Which Direct Nongeneration Emissions Calculation Modules to Apply

Question	Module
Are data available on materials consumption by the T&D project and on the origin of those materials?	Apply Module D1: Embodied Emissions
Are data available on energy consumption during the construction phase of the T&D project?	Apply Module D2: Construction Emissions
Does the T&D project involve clearing any land?	Apply Module D3: Land Clearing Emissions
Does the T&D project include new lines or capacity expansion that includes new SF_6-containing equipment?	Apply Module D4: SF_6 Emissions

Source: Authors' analysis.

border trade connectors—and not to technical loss reduction or increased reliability projects—that install entirely new SF_6-containing equipment in order to account for direct nongeneration emissions from SF_6 leakage.

Step 2. Calculate Direct Nongeneration Emissions for the T&D Projects

This section explains how to use the four modules to calculate direct nongeneration emissions.

Module D1: Embodied Emissions

This module is only applied 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 factor.

Embodied emissions are the product of the mass of materials used and the relevant embodied emission factor, summed across all significant materials.

$$PE_{Emb} = \sum_p (Q_p \times EF_{Emb,p})$$

Where

PE_{Emb} = Project emissions from embodied emissions in construction materials (tCO_2)

Q_p = Quantity of material p used in construction (t)

$EF_{Emb,p}$ = Embodied emission factor of material p (tCO_2e/t)

Parameter	Source
Q_p	Engineering studies in project documentation or feasibility studies
$EF_{Emb,p}$	Table from the IFC CEET, or other similar databases (for example, Hammond and Jones 2008; Öko Institute for Applied Ecology 2009). The 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.

Module D2: Construction Emissions

This module is only applied where the project preparation documentation estimates energy use by construction vehicles.

Emissions are based on the fuel consumption in construction vehicles, the net calorific value of the fuel, and the emission factor of the fuel.

$$PE_{const} = \sum_i (FC_{const,i} \times NCV_i \times EF_{CO_2,i})$$

Where

PE_{const} = Project emissions from energy use in construction (tCO_2)

$FC_{const,i}$ = Quantity of fossil fuel type i consumed during construction (t)

NCV_i = Net calorific value of fossil fuel type i (GJ/t)

$EF_{CO_2,i}$ = Carbon emission factor of fossil fuel type i used in construction (tCO_2e/GJ)

Parameter	Source
$FC_{const,i}$	Project site records, feasibility studies by construction companies, or records from similar construction projects
NCV_i	Local or national default factor, or IPCC 2006 Guidelines
$EF_{CO_2,i}$	IPCC 2006 Guidelines

Module D3: Land Clearing Emissions

This module is based on AM45 and similar methodologies.

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

Where

PE_{LC} = Direct nongeneration emissions from land clearing (tCO_2)

A_{def} = Area of land deforested (ha)

BD = Biomass density per unit area (above ground, below ground, soil carbon, litter, and dead biomass) (tCO_2/ha)

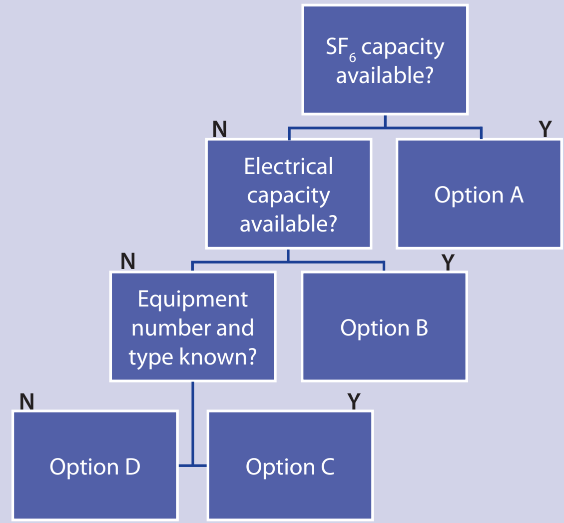
Parameter	Source
A_{def}	Project feasibility documents, or the product of default right of way and line length
BD	IFC CEET table (which is taken from IPCC 2006 Guidelines; see annex A, table A.1 of this report)

Module D4: SF_6 Emissions

This module does not apply to technical loss reduction or increased reliability projects, unless the project contains detailed information on what new SF_6-containing equipment would be installed. If new equipment is specified, Option A may be used for that equipment only. Rehabilitation of existing SF_6-containing equipment is not included, because that equipment was already in the electricity system, and any emissions from it are not incremental emissions from the project activity.

Because this approach should rely on ex ante data, monitoring the changes in the SF_6 inventory and using a mass balance (similar to AM35) is not possible. Rather, the approach must use default emission factors for the various equipment that will be installed, considering the lifetime of that equipment and the maintenance that will be required. It is thus similar to the IPCC Tier 1 approach, except that manufacturing emissions would not be included, since they are upstream of the T&D project. Where detailed equipment capacity data are not available, a default factor based on a portion of national emissions could be used. See the decision tree in figure 6.3 to determine which option to follow.

Figure 6.3: Decision Tree for SF_6 Calculation Approach



Source: Authors' analysis.

Option A: Nameplate SF_6 Capacity for All Equipment Is Available

Where 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 this equipment, standard emission factors can be applied to the SF_6 inventory.

The default emission factors for installation, use, and disposal are in the IPCC 2006 Guidelines for the following equipment (IPCC 2006c, tables 8.2–8.4): sealed-pressure electricity equipment (medium-voltage switchgear), closed-pressure electrical equipment (high-voltage switchgear), and gas-insulated transformers. The project would have to provide data on nameplate capacity (kg SF_6) of all SF_6-containing equipment and separate this inventory into the relevant categories (that is, sealed, closed pressure, gas-insulated transformer). Because the use emission factors are annual leakage, the economic life of the equipment would also be required to calculate lifetime direct nongeneration emissions.

Annual project emissions would therefore be

$$PE_{SF_6,y} = [(Cap_{SP} \times EF_{SF_6,Use,SP}) + (Cap_{CP} \times EF_{SF_6,Use,CP})] \times GWP_{SF_6}$$

Where

$PE_{SF_6,y}$	=	Annual project emissions of SF_6 (tCO_2e/year)
Cap_{SP}	=	Nameplate capacity of all sealed-pressure SF_6-containing equipment used in the project (t SF_6)

$EF_{SF_6,Use,SP}$	= SF_6 operational emission factor for sealed-pressure electrical equipment (% SF_6/year)
Cap_{CP}	= Nameplate capacity of all closed-pressure SF_6-containing equipment used in the project (t SF_6)
$EF_{SF_6,Use,CP}$	= SF_6 operational emission factor for closed-pressure electrical equipment (% SF_6/year)
GWP_{SF_6}	= Global warming potential of SF_6 (23,900 tCO_2e/t SF_6)

Project emissions at disposal would be

$$PE_{SF_6,Disp} = [(Cap_{SP} \times EF_{SF_6,disp,SP}) + (Cap_{CP} \times EF_{SF_6,disp,CP})] \times GWP_{SF_6}$$

Where

$PE_{SF_6,Disp}$	= Project SF_6 emissions at disposal (tCO_2e)
Cap_{SP}	= Nameplate capacity of all sealed-pressure SF_6-containing equipment used in the project (t SF_6)
$EF_{SF_6,disp,SP}$	= SF_6 disposal emission factor for sealed-pressure electrical equipment (% SF_6)
Cap_{CP}	= Nameplate capacity of all closed-pressure SF_6-containing equipment used in the project (t SF_6)
$EF_{SF_6,disp,CP}$	= SF_6 disposal emission factor for closed-pressure electrical equipment (% SF_6)
GWP_{SF_6}	= Global warming potential of SF_6 (23,900)

Parameter	Source
Cap_{SP}	Project preparation documentation
Cap_{CP}	Project preparation documentation
$EF_{SF_6,Use,SP}$	See table 6.2
$EF_{SF_6,Use,CP}$	See table 6.2
GWP_{SF_6}	IPCC 2006 Guidelines (23,900)
$EF_{SF_6,disp,SP}$	Project or manufacturer guidelines for how SF_6 will be disposed of at end of project life
$EF_{SF_6,disp,CP}$	Project or manufacturer guidelines for how SF_6 will be disposed of at end of project life
EL_{SF6}	Manufacturer nameplate ratings of equipment life

The emission factors for use should be as shown in table 6.2, based on the IPCC guidelines:

And total lifetime emissions would be as follows:

$$PE_{SF_6,tot} = \sum_{y=1}^{EL_{SF6}} PE_{SF_6,y} + PE_{SF_6,Disp}$$

Where

Table 6.2: Default Emission Factors for SF_6 Losses in Operation

Type of equipment	%/year of nameplate capacity lost
Sealed pressure SF_6-containing equipment	0.2
Closed pressure SF_6-containing equipment	2.6

Source: IPCC 2006c, tables 8.2 and 8.3.

$PE_{SF_6,tot}$	= Total project emissions from SF_6-containing equipment over project life (tCO_2e)
$PE_{SF_6,y}$	= Annual project emissions of SF_6 (tCO_2e/year)
EL_{SF_6}	= Average economic life of all SF_6-containing equipment (years)
$PE_{SF_6,Disp}$	= Project SF_6 emissions at disposal (tCO_2e)

Option B: Electricity Capacity for All SF_6-Containing Equipment Is Available, But Not SF_6 Capacity

For projects that have a detailed list of all SF_6-containing equipment according to its rated power capacity (for example, 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. This factor is derived from a study by Wartmann and Harnisch (2005) on global SF_6 emissions from the power sector. It converts the power rating into SF_6 capacity, assuming a linear relationship between power and SF_6 use. These estimated SF_6 capacity values are then used in the equations for Option A to estimate SF_6 emissions.

$$Cap_{SP} = Cap_{SP,kV} \times SF_{SP}/1{,}000$$

$$Cap_{CP} = Cap_{CP,kV} \times SF_{CP}/1{,}000$$

Where

Cap_{SP} = Nameplate capacity of all sealed pressure SF_6-containing equipment used in the project (t SF_6)

$Cap_{SP,kV}$ = Nameplate electrical capacity of sealed-pressure SF_6-containing equipment used in the project (kV)

SF_{SP} = Scaling factor for sealed-pressure equipment (kg SF_6/kV capacity)

Cap_{CP} = Nameplate capacity of all closed-pressure SF_6-containing equipment used in the project (t SF_6)

$Cap_{CP,kV}$ Nameplate electrical capacity of closed-pressure SF_6-containing equipment used in the project (kV)

SF_{CP} = Scaling factor for closed-pressure equipment (kg SF_6/kV capacity)

Parameter	Source
$Cap_{SP,kV}$	Project preparation documentation
$Cap_{CP,kV}$	Project preparation documentation
SF_{SP}	See table 6.3
SF_{CP}	See table 6.3

Option C: Only Number and Type of Equipment Is Known, Not Capacity

If only the number of pieces of SF_6-containing equipment is known, and whether they are closed pressure or sealed pressure is specified, the simplified approach here uses an average SF_6 capacity as shown in table 6.3.

$$PE_{SF_6,y} = [(N_{SP} \times ACap_{SP} \times EF_{SF_6,Use,SP}) + (N_{CP} \times ACap_{CP} \times EF_{SF_6,Use,CP})] \times GWP_{SF_6}$$

Where

$PE_{SF_6,y}$ = Annual project emissions of SF_6 (tCO_2e/year)

Table 6.3: Relationship between Power Rating and SF_6 Capacity for T&D Equipment

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-containing equipment	1–52 kV	0.25–10	0.2	5
Closed-pressure SF_6-containing equipment	> 52 kV	3–200	0.5	100

Source: Wartmann and Harnisch 2005.

Note: Scaling factor for closed-pressure equipment assumes that 200 kg capacity would be up to 400 kV equipment.

N_{SP} = Number of pieces of sealed-pressure equipment (no units)

$ACap_{SP}$ = Average capacity of sealed-pressure SF_6-containing equipment (t SF_6)

$EF_{SF_6,Use,SP}$ = SF_6 "use" emission factor for sealed-pressure electrical equipment (% SF_6/year)

N_{CP} = Number of pieces of closed-pressure equipment (no units)

$ACap_{CP}$ = Average capacity of closed-pressure SF_6-containing equipment (t SF_6)

$EF_{SF_6,Use,CP}$ = SF_6 operational emission factor for closed-pressure electrical equipment (% SF_6/year)

GWP_{SF_6} = Global warming potential of SF_6 (23,900 tCO_2e/t SF_6)

$$PE_{SF_6,tot} = \sum_{y=1}^{EL_{SF_6}} PE_{SF_6,y}$$

Where

$PE_{SF_6,tot}$ = Total project emissions from SF_6-containing equipment over project life (tCO_2e)

$PE_{SF_6,y}$ = Annual project emissions of SF_6 (tCO_2e/year)

EL_{SF_6} = Average economic life of all SF_6-containing equipment (years)

Parameter	Source
N_{SP}	Project preparation documentation
N_{CP}	Project preparation documentation
$ACap_{SP}$	See table 6.3
$ACap_{CP}$	See table 6.3
$EF_{SF_6,Use,SP}$	See table 6.2
$EF_{SF_6,Use,CP}$	See table 6.2
GWP_{SF_6}	IPCC 2006 Guidelines (23,900)
EL_{SF_6}	Manufacturer nameplate ratings of equipment life

Note that disposal emissions are not included because of high uncertainty and the fact that these data are unlikely to be available if there is no detailed SF_6 capacity inventory.

Option D: No Inventory of SF_6-Containing Equipment Is Available

Where there is no detailed inventory of equipment using SF_6 during project preparation, average SF_6 use over the entire power sector for that country is used as the basis for determining a default emission factor per unit of electricity (for example, kg SF_6/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.

$$PE_{SF_6,y} = [(ELEC_{HV} \times EF_{SF_6,z} \times 0.75) + (ELEC_{MV} \times EF_{SF_6,z} \times 0.25)] \times GWP_{SF_6}/10^6$$

Where

$PE_{SF_6,y}$ = Annual project emissions of SF_6 (tCO_2e/year)

$ELEC_{HV}$ = Electricity transmitted by the project activity over new high-voltage lines (> 100kV), measured at the exporting substation (MWh/year)

$EF_{SF_6,z}$ = Average SF_6 emission factor for power sector in country z (g SF_6/MWh)

$ELEC_{MV}$ = Electricity transmitted by project activity over new medium-voltage lines (38–100 kV), measured at the exporting substation (MWh/year)

GWP_{SF_6} = Global warming potential of SF_6 (23,900 tCO_2e/t SF_6)

$$PE_{SF_6,tot} = \sum_{y=1}^{EL_{SF_6}} PE_{SF_6,y}$$

Where

$PE_{SF_6,tot}$ = Total project emissions from SF_6-containing equipment over project life (tCO_2e)

$PE_{SF_6,y}$ = Annual project emissions of SF_6 (tCO_2e/year)

EL_{SF_6} = Average economic life of all SF_6-containing equipment (years)

Parameter	Source
$ELEC_{HV}$	Project preparation documentation
$ELEC_{MV}$	Project preparation documentation
$EF_{SF_6,z}$	Calculated from the U.S. EPA's inventory of SF_6 fugitive emissions from the power sector by country (U.S. EPA 2006) and the IEA's reported electricity consumption by country (U.S. EIA 2010), or similar sources
EL_{SF_6}	Manufacturer nameplate ratings of equipment life

Step 3. Determine How Baseline and Project Emissions for Power Generation Effects Should Be Calculated

To determine which modules to use for calculating baseline and project emissions for the T&D project, the decision trees shown in figures 6.4–6.8 should be used. There is a decision tree for each major project type, indicating which modules should be applied to calculate baseline and project emissions using the designations "BE1," "PE1," and so on. Where a T&D investment package has more than one component (for example, capacity expansion and increased reliability), both modules should be applied with relevant data from the project preparation documentation. All the modules are described in detail below.

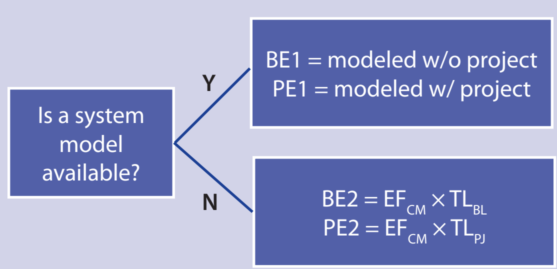
The questions in the decision trees are as follows:

- **Is a system model available?** Where there is a detailed power systems analysis model available, the most accurate approach for estimating GHG emissions is based on modeled power generation and/or fuel consumption using short- and mid-term simulation models such as load flow and long-term economic dispatch simulations.
- **Identified alternative to additional electricity?** This question concerns whether the project technical and economic analysis identifies a specific alternative source of power that would be used if the project were not implemented. This could be an existing captive power source, or a source that is likely to be constructed in the absence of the project.
- **Identified source of incremental supply?** This question concerns whether the additional electricity delivered by the T&D project is coming from a new power plant constructed to supply the T&D system. This could be the case, for example, with a new power plant built to export power through a new interconnector. The project team would have to justify that the entire supply for the T&D project would come from the new plant. This could be based on the timing of construction, similarity in capacity of the plant and the new T&D capacity, and contractual agreements between the grid operator and the owners of the new plant.

Step 4. Calculate Baseline Power Generation Emissions for the T&D Projects

Both baseline and project emissions are always calculated over the life of the project, since the

Figure 6.4: Decision Tree for Technical Loss Reduction Projects



Source: Authors' analysis.

Figure 6.5: Decision Tree for Increased Reliability Projects

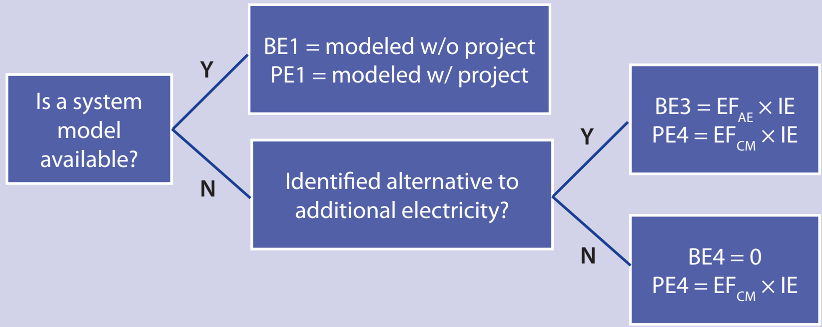


Figure 6.6: Decision Tree for T&D Capacity Expansion Projects

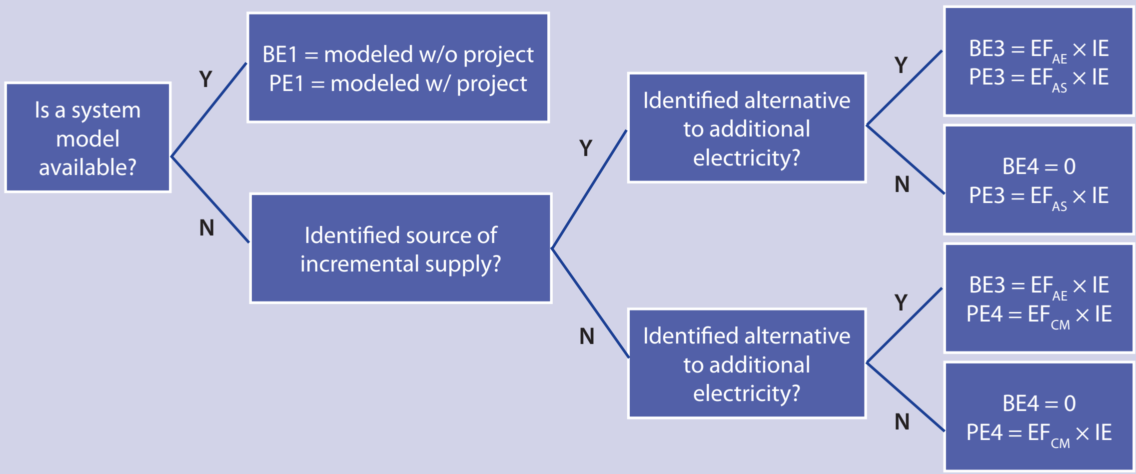


Figure 6.7: Decision Tree for Electrification Projects

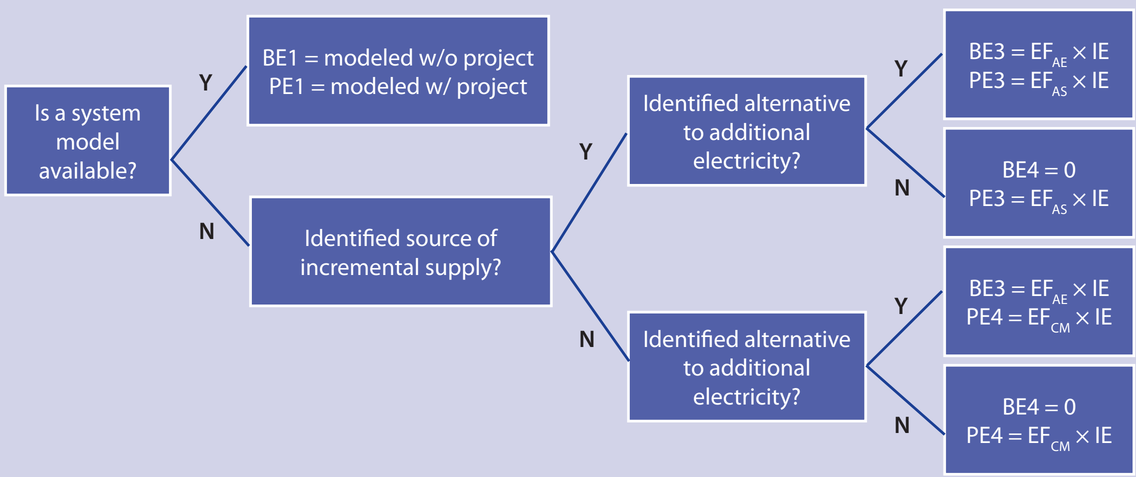
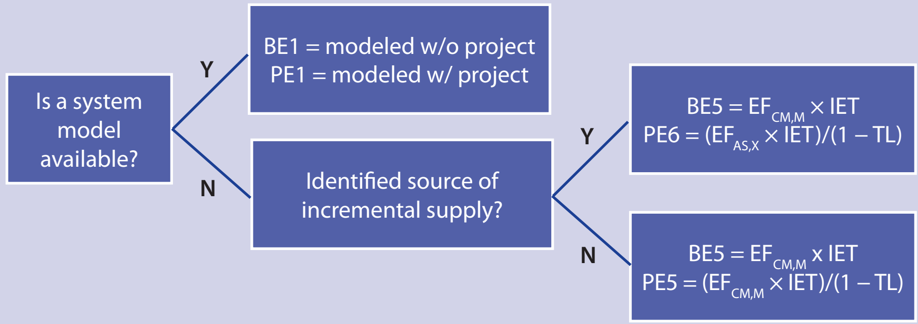


Figure 6.8: Decision Tree for Cross-Border Trade Projects



total electricity flowing through the project can change over time. Thus, the following questions are summed over all years y of the project life. The economic life should be the same one used in the feasibility study for the project.

Module BE1 and BE1A: Modeled Baseline Emissions

This module is used for any project where a detailed power system model is available that can estimate power generation by each plant with and without the project.

Option A: Using Conversion Efficiencies

If the model only reports power generation by plant, and not fuel consumption, baseline emissions are calculated as follows:

$$BE_1 = \sum_{y=1}^{n}\sum_{k}[(EG_{BL,k,y}/\eta_k) \times 3.6 \times EF_{CO_2,i}]$$

Where

BE_1 = Baseline emissions modeled over project life (tCO_2)

$EG_{BL,k,y}$ = Electricity generated by grid-connected power plant k in the "without project" scenario in modeled year y (MWh)

η_k = Conversion efficiency of grid-connected power plant k (%)

3.6 = Unit conversion factor (GJ/MWh)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

n = Economic life of project (years)

Option B: Using Plant-Level Fuel Consumption

If fuel consumption for each power plant is provided by the power system model, baseline emissions are given as follows:

$$BE_1 = \sum_{y=1}^{n}\sum_{i,k}(FC_{BL,i,k,y} \times NCV_i \times EF_{CO_2,i})$$

Where

BE_1 = Baseline emissions modeled over project life (tCO_2)

$FC_{BL,i,k,y}$ = Consumption of fuel type i in grid-connected plant k in the "without project" scenario in modeling year y (t)

NCV_i = Net calorific value of fuel type i (GJ/t)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

n = Economic life of project (years)

Parameter	Source
$EG_{BL,k,y}$	Power system model
η_k	Conversion efficiency should come from 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 (2009d) (see annex A, table A.3)
$EF_{CO_2,i}$	IPCC 2006 Guidelines
n	Project preparation documentation
$FC_{BL,i,k,y}$	Power system model
NCV_i	Local or national default factor, or IPCC 2006 Guidelines

Baseline emissions Module 1A is almost the same, except that it is the sum of modeled emissions for two separate grids that are connected by the cross-border trade project.

$$BE_{1A} = \sum_{y=1}^{n} \{ \sum_{x} [(EG_{BL,x,y}/\eta_x) \times 3.6 \times EF_{CO2,i}] + \sum_{m} [(EG_{BL,m,y}/\eta_m) \times 3.6 \times EF_{CO2,i}] \}$$

Where

BE_{1A} = Baseline emissions modeled over project life (tCO_2)

$EG_{BL,x,y}$ = Electricity generated by grid-connected power plant x in the exporting grid in the "without project" scenario in modeled year y (MWh)

η_x = Conversion efficiency of exporting grid-connected power plant x (%)

3.6 = Unit conversion factor (GJ/MWh)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

$EG_{BL,m,y}$ = Electricity generated by grid-connected power plant m in the importing grid in the "without project" scenario in modeled year y (MWh)

η_m = Conversion efficiency of importing grid-connected power plant m (%)

n = Economic life of project (years)

If fuel consumption for each power plant is provided by the power system model, baseline emissions for the two systems are given as follows:

$$BE_{1A} = \sum_{y=1}^{n} [\sum_{i,x} (FC_{BL,i,x,y} \times NCV_i \times EF_{CO_2,i}) + \sum_{i,m} (FC_{BL,i,m,y} \times NCV_i \times EF_{CO_2,i})]$$

Where

BE_{1A} = Baseline emissions modeled over project life (tCO_2)

$FC_{BL,i,x,y}$ = Consumption of fuel type i in exporting grid-connected plant x in the "without project" scenario in modeling year y (t)

NCV_i = Net calorific value of fuel type i (GJ/t)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

$FC_{BL,i,m,y}$ = Consumption of fuel type i in importing grid-connected plant m in the "without project" scenario in modeling year y (t)

n = Economic life of project (years)

Parameter	Source
$EG_{BL,x,y}$	Power system model
$EG_{BL,m,y}$	Power system model
η_x, η_m	Conversion efficiency should come from 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 (2009d) (see annex A, table A.3)
$EF_{CO_2,i}$	IPCC 2006 Guidelines
n	Project preparation documentation
$FC_{BL,i,k,y}$	Power system model
NCV_i	Local or national default factor, or IPCC 2006 Guidelines

Module BE2: Emissions from Existing Technical Loss Rates

This module is used for a project that reduces power generation but where there is no power system model available to estimate change in plant-level generation. The module is thus for technical loss reduction projects.

$$BE_2 = \sum_{y=1}^{n}(TL_{BL,y} \times EF_{CM})$$

Where

BE_2 = Baseline emissions from losses (tCO_2)

$TL_{BL,y}$ = Estimated technical losses in year y without the project (MWh)

EF_{CM} = Combined margin emission factor for the interconnected grid, based on UNFCCC (2009d) (tCO_2/MWh)

n = Economic life of project (years)

Parameter	Source
$TL_{BL,y}$	Power system model
EF_{CM}	Calculated using UNFCCC (2009d) with ex ante options for operating and build margins. The operating margin should be calculated as the simple operating margin if low-cost/must-run resources are less than 50% of total power generation, or as the weighted average operating margin if low-cost/must-run resources are more than 50% of total generation. New plants that are committed to new capacity should be included in the margin calculations.
n	Project preparation documentation

Module BE3: Emissions from Alternative Baseline Energy Source

This module is used where more electricity is delivered to the system by the T&D project, and there is a clearly identified alternative baseline energy source in the project preparation documentation. In other words, the project documents either specify the current energy sources that will be displaced or the alternatives that would have been built or used if the project had not been implemented.

$$BE_3 = \sum_{y=1}^{n}(IE_y \times EF_{AE})$$

Where

BE_3 = Baseline emissions for project with identified alternative energy source (tCO_2)

IE_y = Incremental electricity transmitted and distributed as a result of the project in year y (MWh)

EF_{AE} = Emission factor for the alternative baseline energy supply source (tCO_2/MWh)

n = Economic life of project (years)

Parameter	Source
IE_y	Project preparation documentation
EF_{AE}	If the alternative energy supply source is an on-site/captive power supply plant, the emission factor for the alternative energy supply source should come from one of the following, *in order of preference*: ▪ Source 1: Historical measurements if the alternative energy supply source already exists or can be identified. ▪ Source 2: Survey of local industry and commercial facilities to show the type of backup power used (for example, fuel type, generation capacity), efficiency of that power supply, and/or fuel consumption ▪ Source 3: Relevant national or regional studies on backup power supplies to determine the typical mix of capacity, fuel type, and efficiency/fuel consumption ▪ Source 4: Default emission factor for diesel power generation from AMS I.D. "Grid Connected Renewable Electricity Generation" (that is, 0.8 tCO_2/MWh for units over 200 kW capacity) If the alternative supply source is a minigrid, refer to equation below
n	Project preparation documentation

If the alternative supply source is an isolated minigrid, the emission factor is calculated as follows:

$$EF_{AE} = (\sum_{k,i} FC_{BLk,i} \times NCV_i \times EF_{CO_2,i}) / \sum_k EG_{BL,k}$$

Where

EF_{AE} = Emission factor for the alternative baseline energy supply source (tCO_2/MWh)

$FC_{BLk,i}$ = Quantity of fuel type i consumed by minigrid power source k in the most recent three years (t or liters)

NCV_i = Net calorific value of fuel type i (GJ/t or liter)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

$EG_{BL,k}$ = Electricity generated by minigrid power source k in most recent three years (MWh)

Parameter	Source
$FC_{BLk,i}$	Local utility records or minigrid operator records
NCV_i	Local or national default factor, or IPCC 2006 Guidelines
$EF_{CO_2,i}$	IPCC 2006 Guidelines
$EG_{BL,k}$	Local utility records or minigrid operator records

Module BE4: No Emissions in the Baseline

For many of the project types where there is no alternative baseline energy source specified in the project documentation, it is assumed that there would not be power consumption in the absence of the project. In other words, the new or expanded end uses supplied by the project (for example, new commercial and industrial facilities, or new housing areas) would not have been constructed or would not have had access to electricity. In the majority of cases, the T&D project preparation process will identify and document the energy alternatives to increased grid power supply. However, there will be cases where the alternatives are unknown, or where it is unlikely that any supply would have existed without the project. This baseline alternative accommodates that situation.

Module BE5: Emissions from Importing Grid

This module is used for cross-border trade projects where this is no power system model available to project plant-level power generation with and without the project. Although in practice there may be some two-way flow of power on the transmission line, and there may also have been some historical electricity trade, only the incremental flow of power from the exporting to importing country should be considered in estimating the net emissions impact of the transmission investment.

$$BE_5 = \sum_{y=1}^{n}(IET_{m,y} \times EF_{CM,m})$$

Where

BE_5 = Baseline emissions for cross-border trade project (tCO_2)

$IET_{m,y}$ = Projected incremental electricity received in the importing country because of the project in year *y*, measured at receiving substation (MWh)

$EF_{CM,m}$ = Combined margin emission factor for the importing grid (tCO_2/MWh)

n = Economic life of project (years)

Parameter	Source
$IET_{m,y}$	Project preparation documentation
$EF_{CM,m}$	Calculated for the importing grid using UNFCCC (2009d) with ex ante options for operating and build margin. The operating margin should be calculated as the simple operating margin if low-cost/must-run resources are less than 50% of total power generation, or as the weighted average operating margin if low-cost/must-run resources are more than 50% of total generation. New plants that are committed to new capacity should be included in the margin calculations.
n	Project preparation documentation

Step 5. Calculate Project Power Generation Emissions for the T&D Projects

Module PE1 and PE1A: Modeled Project Emissions

This module is used for any project where a detailed power system model is available that can estimate power generation by each plant with and without the project. If the model only reports power generation by plant and not fuel consumption, project emissions are calculated as follows:

$$PE_1 = \sum_{y=1}^{n}\sum_{k}[(EG_{PJ,k,y}/\eta_k) \times 3.6 \times EF_{CO_2,i}]$$

Where

PE_1 = Project emissions modeled over project life (tCO_2)

$EG_{PJ,k,y}$ = Electricity generated by grid-connected power plant *k* in the "with project" scenario in modeled year *y* (MWh)

η_k = Conversion efficiency of grid-connected power plant *k* (%)

3.6 = Unit conversion factor (GJ/MWh)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type *i* (tCO_2/GJ)

If fuel consumption for each power plant is provided by the power system model, project emissions are given as follows:

$$PE_1 = \sum_{y=1}^{n}\sum_{i,k}(FC_{BL,i,k,y} \times NCV_i \times EF_{CO_2,i})$$

Where

PE_1 = Project emissions modeled over project life (tCO_2)

$FC_{BL,i,k,y}$ = Consumption of fuel type *i* in grid connected plant *k* in the "with project" scenario in modeled year *y* (t)

NCV_i = Net calorific value of fuel type *i* (GJ/t)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type *i* (tCO_2/GJ)

Parameter	Source
$EG_{PJ,k,y}$	Power system model
η_k	Conversion efficiency should come from 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 (2009d) (see annex A, table A.3)
$EF_{CO_2,i}$	IPCC 2006 Guidelines
n	Project preparation documentation
$FC_{PJ,i,k,y}$	Power system model
NCV_i	Local or national default factor, or IPCC 2006 Guidelines

Project emissions Module 1A is almost the same, except that it is the sum of modeled emissions for two separate grids that are connected by the cross-border trade project.

$$PE_{1A} = \sum_{y=1}^{n} \{\sum_{x}[(EG_{PJ,x,y}/\eta_x) \times 3.6 \times EF_{CO_2,i}] +$$
$$\sum_{m}[(EG_{PJ,m,y}/\eta_m) \times 3.6 \times EF_{CO_2,i}]\}$$

Where

PE_{1A} = Project emissions modeled over project life (tCO_2)

$EG_{PJ,x,y}$ = Electricity generated by grid-connected power plant x in the exporting grid in the "with project" scenario in modeled year y (MWh)

η_x = Conversion efficiency of exporting grid-connected power plant x (%)

3.6 = Unit conversion factor (GJ/MWh)

$EF_{CO^2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

$EG_{PJ,m,y}$ = Electricity generated by grid-connected power plant m in the importing grid in the "with project" scenario in modeled year y (MWh)

η_m = Conversion efficiency of importing grid-connected power plant m (%)

n = Economic life of project (years)

If fuel consumption for each power plant is provided by the power system model, project emissions for the two systems are given as follows:

$$PE_{1A} = \sum_{y=1}^{n} [\sum_{i,x}(FC_{PJ,i,x,y} \times NCV_i \times EF_{CO_2,i}) +$$
$$\sum_{i,m}(FC_{PJ,i,m,y} \times NCV_i \times EF_{CO_2,i})]$$

Where

PE_{1A} = Baseline emissions modeled over project life (tCO_2)

$FC_{PJ,i,x,y}$ = Consumption of fuel type i in exporting grid-connected plant x in the "with project" scenario in modeling year y (t)

NCV_i = Net calorific value of fuel type i (GJ/t)

$EF_{CO_2,i}$ = Carbon emission factor of fuel type i (tCO_2/GJ)

$FC_{PJ,i,m,y}$ = Consumption of fuel type i in importing grid-connected plant m in the "with project" scenario in modeling year y (t)

n = Economic life of project (years)

Parameter	Source
$EG_{PJ,x,y}$	Power system model
$EG_{PJ,m,y}$	Power system model
η_x, η_m	Conversion efficiency should come from 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 (2009d) (see annex A, table A.3)
$EF_{CO_2,i}$	IPCC 2006 Guidelines
n	Project preparation documentation
$FC_{BL,i,k,y}$	Power system model
NCV_i	Local or national default factor, or IPCC 2006 Guidelines

Module PE2: Emissions from Expected Project Technical Loss Rates

This module is used for a project that reduces power generation but where there is no power system model available to estimate changes in plant-level generation. This module is thus for technical loss reduction projects.

$$PE_2 = \sum_{y=1}^{n}(TL_{PJ,y} \times EF_{CM})$$

Where

PE_2 = Project emissions from losses (tCO_2)

$TL_{PJ,y}$ = Estimated technical losses in year y with the project (MWh)

EF_{CM} = Combined margin emission factor for the interconnected grid, based on UNFCCC (2009d) (tCO_2/MWh)

n = Economic life of project (years)

Parameter	Source
$TL_{PJ,y}$	Power system model
EF_{CM}	Calculated using UNFCCC (2009d) with ex ante options for operating and build margin. The operating margin should be calculated as the simple operating margin if low-cost/must-run resources are less than 50% of total power generation, or as the weighted average operating margin if low-cost/must-run resources are more than 50% of total generation. New plants that are committed to new capacity should be included in the margin calculations.
n	Project preparation documentation

Module PE3: Emissions from Identified New Source of Supply

Where there is a clearly identified source of new supply that will provide the power in the T&D project, the emission factor for this source of supply is used rather than a combined margin grid emission factor.

$$PE_3 = \sum_{y=1}^{n}(IE_y \times EF_{AS})$$

Where

PE_3 = Project emissions for project with identified new source of supply (tCO_2)

IE_y = Incremental electricity transmitted and distributed as a result of the project in year y (MWh)

EF_{AS} = Emission factor for the new source of supply (tCO_2/MWh)

n = Economic life of project (years)

Parameter	Source
IE_y	Project preparation documentation
EF_{AS}	The emission factor for the new source of supply may be determined in several ways, *in order of preference*: ▪ Source 1: Estimated project-specific annual fuel consumption and power generation, calculated according the equation below ▪ Source 2: Based on manufacturer nameplate efficiency rating, calculated according to the equation below ▪ Source 3: Feasibility studies for the new source of supply ▪ Source 4: Default efficiencies from UNFCCC (2009d) (see annex A, table A.3)
n	Project preparation documentation

Equation for Source 1: Estimated Project-Specific Annual Fuel Consumption and Power Generation

$$EF_{AS} = (\sum_i FC_{AS,i} \times NCV_i \times EF_{CO_2,i})/EG_{AS}$$

Where

EF_{AS} = Emission factor for the new source of supply (tCO_2/MWh)

$FC_{AS,i}$ = Estimated annual fossil fuel type i consumed by new power unit (mass or volume unit)

NCV_i = Net calorific value (energy content) of fossil fuel type i (GJ/mass or volume unit)

$EF_{CO_2,I}$ = Carbon emission factor of fossil fuel type i (tCO_2/GJ)

EG_{AS} = Estimated annual net generation by new power unit (MWh)

Parameter	Source
$FC_{AS,i}$	Project preparation documentation, feasibility studies for new power plant, or utility data
EG_{AS}	Project preparation documentation, feasibility studies for new power plant, or utility data
NCV_i	Local or national default factor, or IPCC 2006 Guidelines
$EF_{CO_2,i}$	IPCC 2006 Guidelines

Equation for Source 2: Based on Manufacturer Nameplate Efficiency Rating

$$EF_{AS} = (EF_{CO_2,i} \times 3.6)/\eta_{AS,y}$$

Where

EF_{AS} = Emission factor for the new source of supply (tCO_2/MWh)

$EF_{CO_2,i}$ = Carbon emission factor of fossil fuel type i (tCO_2/GJ)

η_{AS} = Manufacturer nameplate efficiency rating for new power unit (%)

Parameter	Source
$EF_{CO_2,i}$	IPCC 2006 Guidelines
η_k	Manufacturer nameplate efficiency rating

Module PE4: Emissions from Project Grid

Project emissions are from increased grid supply, and are calculated as shown below. This assumes that the project does not lead to an increase in overall technical losses in the T&D system. If there is an increase in the technical losses, such as in an electrification project involving a long-line extension to a remote village, the incremental losses are considered.

$$PE_4 = \sum_{y=1}^{n}(IE_y \times EF_{CM})/(1 - IL)$$

Where

PE_4 = Project emissions for project with identified new source of supply (tCO_2)

IE_y = Incremental electricity transmitted and distributed as a result of the project in year y (MWh)

EF_{CM} = Combine margin emission factor of electricity grid (tCO_2/MWh)

n = Economic life of project (years)

IL = Incremental technical losses caused by the project (%)

Parameter	Source
IE_y	Project preparation documentation
EF_{CM}	Calculated using UNFCCC (2009d) with ex ante options for operating and build margin. The operating margin should be calculated as the simple operating margin if low-cost/must-run resources are less than 50% of total power generation, or as the weighted average operating margin if low-cost/must-run resources are more than 50% of total generation. New plants that are committed to new capacity should be included in the margin calculations.
n	Project preparation documentation
IL	This would be zero for most projects, unless the project preparation documentation specifies that the project activity involves a major line extension that would have higher technical losses than the local grids or power generation systems it is displacing. In the latter case, the project preparation documentation would be the source for the incremental technical losses.

Module PE5: Emissions from Exporting Grid

This module is used for cross-border trade projects where this is no power system model available to estimate plant-level power generation with and without the project. Although in practice there may be some two-way flow of power on the transmission line and there may also have been some historical electricity trade, only the incremental flow of power from the exporting to importing country should be considered in estimating the net emissions impact of the transmission investment.

$$PE_5 = \sum_{y=1}^{n}(IET_{m,y} \times EF_{CM,x})/(1 - TL_{IC})$$

Where

PE_5	=	Project emissions for cross-border trade project (tCO_2)
$IET_{m,y}$	=	Projected incremental electricity received in the importing country because of the project in year *y*, measured at receiving substation (MWh)
$EF_{CM,x}$	=	Combined margin emission factor for the exporting grid (tCO_2/MWh)
TL_{IC}	=	Technical losses on new interconnector (%)
n	=	Economic life of project (years)

Parameter	Source
$IET_{m,y}$	Project preparation documentation
$EF_{CM,x}$	Calculated for the exporting grid using UNFCCC (2009d) with ex ante options for operating and build margin. The operating margin should be calculated as the simple operating margin if low-cost/must-run resources are less than 50% of total power generation, or as the weighted average operating margin if low-cost/must-run resources are more than 50% of total generation. New plants that are committed to new capacity should be included in the margin calculations.
TL_{IC}	Project preparation documentation
n	Project preparation documentation

Module PE6: Emissions from Identified New Source of Supply for Export

This module is used for cross-border trade projects where this is no power system model available to project long-term plant-level power generation with and without the project, and where there is an identified new power plant that will produce the electricity for export. Although in practice there may be some two-way flow of power on the transmission line and there may also have been some historical electricity trade, to estimate the net emissions impact of the transmission investment, only the incremental flow of power from the exporting to importing country should be considered.

$$PE_6 = \sum_{y=1}^{n}(IET_{m,y} \times EF_{AS})/(1 - TL_{IC})$$

Where

PE_6	=	Project emissions for cross-border trade project (tCO_2)
$IET_{m,y}$	=	Projected incremental electricity received in the importing country because of the project in year *y*, measured at receiving substation (MWh)
EF_{AS}	=	Emission factor for the new source of supply (tCO_2/MWh)
TL_{IC}	=	Technical losses on new interconnector (%)
n	=	Economic life of project (years)

Parameter	Source
$IET_{m,y}$	Project preparation documentation
EF_{AS}	The emission factor for the new source of supply may be determined in several ways, *in order of preference*: ▪ Source 1: Estimated project-specific annual fuel consumption and power generation, calculated according the equation below. ▪ Source 2: Based on manufacturer nameplate efficiency rating, calculated according to the equation below ▪ Source 3: Feasibility studies for the new source of supply ▪ Source 4: Default efficiencies from UNFCCC (2009d) (see annex A, table A.3)
TL_{IC}	Project preparation documentation
n	Project preparation documentation

Equation for Source 1: Estimated Project-Specific Annual Fuel Consumption and Power Generation

$$PE_2 = (\sum_i FC_{AS,i} \times NCV_i \times EF_{CO_2,i})/EG_{AS}$$

Where

EF_{AS} = Emission factor for the new source of supply (tCO_2/MWh)

$FC_{AS,i}$ = Estimated annual fossil fuel type *i* consumed by new power unit (mass or volume unit)

NCV_i = Net calorific value (energy content) of fossil fuel type *i* (GJ/mass or volume unit)

$EF_{CO_2,I}$ = Carbon emission factor of fossil fuel type *i* (tCO_2/GJ)

EG_{AS} = Estimated annual net power generation by new power unit (MWh)

Parameter	Source
$FC_{AS,i}$	Project preparation documentation, feasibility studies for new power plant, or utility data
EG_{AS}	Project preparation documentation, feasibility studies for new power plant, or utility data
NCV_i	Local or national default factor, or IPCC 2006 Guidelines
$EF_{CO_2,i}$	IPCC 2006 Guidelines

Equation for Source 2: Based on Manufacturer Nameplate Efficiency Rating

$$EF_{AS} = (EF_{CO_2,i} \times 3.6)/\eta_{AS,y}$$

Where

EF_{AS} = Emission factor for the new source of supply (tCO_2/MWh)

$EF_{CO_2,I}$ = Carbon emission factor of fossil fuel type *i* (tCO_2/GJ)

η_{AS} = Manufacturer nameplate efficiency rating for new power unit (%)

Parameter	Source
$EF_{CO_2,i}$	IPCC 2006 Guidelines
η_k	Manufacturer nameplate efficiency rating

Note on Emission Factors for Cross-Border Trade Projects

Most large high-voltage transmission interconnection projects financed by the World Bank are expected to conduct short- and long-term power system simulation studies, which directly provide emission factors and emissions reductions for different integration scenarios and different dispatch rules. However, in the absence of these studies, some assumptions will have to be made on emission factors. These assumptions include what type of operating margin should be used and whether a build margin should also be included in the grid emission factor. For the importing grid, most of the proposals have included both operating and build margins, on the grounds that imported power is being used in many countries to substitute or delay new construction of power plants. As discussed earlier, the Methodologies Panel suggested using the minimum of operating and build margins for the grid emission factor, and basing the operating margin on ex post dispatch data, if the data were available, or other accepted approaches. No other methodology guideline or approved baseline methodology specifies using the minimum of operating and build margins.[3] The approach suggested here is therefore to use the combined margin, with ex ante simple operating margin and ex ante build margin with 50-50 weighting. If historical dispatch data are available to construct a more detailed operating margin, this may also be used.

An alternative would be to decide whether to include the build margin for the importing grid based on two factors: (1) the amount of imports prior to the project activity *relative to the total consumption* of electricity in the importing country;[4]

[3] The only exception among all the approved CDM methodologies and tools is AM29 for grid-connected gas-fired power plants.

[4] Note that this is different from the question of whether absolute project size should influence the weightings of the operating and build margins, as discussed by the UNFCCC (2005, annex 2).

Table 6.4: Decision Matrix for Whether to Use Build Margin as Part of Baseline (Importing Country) Electricity Emission Factor

Project projected imports relative to total electricity consumption in importing country	Imports relative to total electricity consumption in importing country prior to project activity	
	Below threshold (for example, < 50%)	Above threshold (for example, > 50%)
Above threshold (for example, > 10%)	Yes	Yes
Below threshold (for example, < 10%)	No	Yes

Source: Authors' analysis.

and (2) the projected amount of imports from the project activity relative to total consumption of electricity in the importing country (both average of last three years). Table 6.4 shows how these two variables would affect the use of the build margin. The exact thresholds would require further research.

For the exporting grid, the proposals reviewed take different approaches, from dispatch data, to combined margin, to using the emission factor of the most carbon-intensive plant on the exporting grid. Given that the approved methodology for grid extension (AM45) uses the combined margin, and that this can be used for relatively large flows of existing and new power generation, it is suggested that the combined margin for the exporting country be used for this type of transmission project. Alternatively, a matrix similar to that in table 6.4 could be used to determine the extent to which the build margin should be included. As discussed above, where a single new plant can be identified as the source for practically all of the export power, the emission factor for this plant should be used rather than a grid emission factor.

Table 6.5: Example of Summary Table for T&D Project GHG Emissions (all tCO_2 over project life)

Direct nongeneration impacts			
Embodied emissions	5,000		
Energy in construction	12,000		
Land clearing	33,000		
SF_6	1,500		
	Baseline	Project	Net
Direct generation impacts			
Technical loss reduction	30,000	10,000	–20,000
Indirect generation impacts			
Increased reliability			
Capacity expansion	25,000	30,000	5,000
Electrification			
Cross-border trade			

Source: Authors' analysis.

Step 6. Summarize GHG Emissions Impacts

The GHG emissions impacts of the T&D project should be summarized as shown in table 6.5. Because the various impacts are qualitatively different in terms of their effect on the overall power sector, they should be reported separately rather than summed.

7. Case Studies

Three case studies from actual operations in the early stages of the project pipeline were selected to test the proposed approach. The type of investments considered are a good representation of the different types of interventions typically present in loans that contain T&D components. The case studies were developed using the approach and modules described in the previous chapters. The aim in undertaking these case studies was to evaluate the proposed methodology, in particular with respect to its ease (feasibility) of implementation and its reliability in determining the GHG impacts of interventions. In most cases, the project data reviewed were part of the feasibility studies from project preparation. Feasibility studies were prepared in most of the cases by external consultants working with the World Bank project teams. Besides the data contained in feasibility studies, the environmental and social assessments were consulted, as well as other information from project preparation described in the project appraisal documents.

The three case studies chosen were from the following operations:

- **Case study 1:** Ethiopia-Kenya Power Systems Interconnection Project
- **Case study 2:** Energy Access Scale-Up Program, Kenya
- **Case study 3:** Eletrobras Distribution Rehabilitation Project, Brazil

The first project corresponds to preliminary feasibility studies, but not a pipeline project. The second and third case studies are already at advanced stages of approval.

Case Study 1: Ethiopia-Kenya Power Systems Interconnection Project

The project is an interconnector for the Ethiopia and Kenya power systems over a high-voltage transmission line starting from Wolayta/Sodo on the Ethiopian side and ending in the Nairobi area on the Kenya side. Depending on the location of the landing point on the Kenya side, the transmission line will cover approximately 1,200 km.

Under various assumptions on energy exchanges with Sudan, Egypt, and Djibouti, and the hydrological risks in Ethiopia, a two-stage development of the interconnection capacity to Kenya has been defined:

- **Phase 1:** 1,000 MW transfer capacity by 2012, the year of the targeted availability of hydropower from Gilbel Gibe III in Ethiopia
- **Phase 2:** 2,000 MW transfer capacity beyond 2020 up to the planning horizon of 2030

The very long interconnection and the high transfer capacity allow for the use of either high-voltage AC or DC technologies (or combinations thereof) to ensure acceptable technical and economical performance. The relevant data for this project were from the feasibility study prepared by Fichtner (2008).

Description of Modules and Data Availability

Step 1: Determine Which Direct Nongeneration Emissions Will Be Included

Based on the project type and data availability, the following table determines which direct nongeneration emissions calculation modules apply to this project.

Question	Answer
Are data available on materials consumption by the T&D project and on the origin of those materials?	No
Are data available on energy consumption during the construction phase of the T&D project?	No
Does the T&D project involve clearing any land?	Yes (Apply Module D3: Land Clearing Emissions)
Does the T&D project include new lines or capacity expansion that includes new SF_6-containing equipment?	Yes (Apply Module D4: SF_6 Emissions)

Step 2: Calculate Direct Nongeneration Emissions for the T&D Projects

Module D3: Land Clearing Emissions. The executive summary mentions that the right of way for the high-voltage AC 400 kV double circuit line is 60 m. The right of way for a high-voltage DC bipolar 500 kV line is 50 m, except in populated areas where the right of way increases up to 70 m. A figure of 60 m has therefore been taken as an appropriate compromise for this project. With respect to the potential emissions from land clearing, an assumption has been made from the limited information available in the FSR that the land can be described as "Cropland—Tropical (moist region), perennial woody biomass" according to the IFC CEET table; the relevant biomass density has therefore been applied.

The results for this module are summarized below:

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

Parameter	Unit	Value
$_{def}$	ha	7,200
BD	tCO_2/ha	77
PE_{LC}		554,400

Module D4: SF_6 Emissions. Since no information was available on the nameplate capacity of the SF_6-containing equipment, nor on the electrical capacity of this equipment, the option chosen was to use a default value for SF_6 emissions from electrical power systems, and multiply that figure by the electricity transmitted over the new line on an annual basis. Since no figure was available for SF_6 emissions from electrical power systems in either Ethiopia or Kenya, the default emission factor for Africa as a whole was chosen (0.13 g SF_6/MWh). The results of this assessment are presented below. As the totality of the line is considered to be a high-voltage line (500 kV and 400 kV), 75 percent of the default emission factor is used.

$$PE_{SF6,y} = [(ELEC_{HV,y} \times EF_{SF6,z} \times 0.75) + (ELEC_{MV,y} \times EF_{SF6,z} \times 0.25)] \times GWP_{SF6}/10^6$$

Parameter	Unit	Value
$ELEC_{HV}$	MWh	111,118,518
EF_{SF_6z}	g SF_6/MWh	0.13
$ELEC_{MV}$	MWh	0
GWP_{SF_6}	tCO_2e/t SF_6	23,900
PE_{SF_6y}		249,971

Step 3: Determine How Baseline and Project Emissions from Power Generation Should Be Calculated

The decision tree for cross-border trade projects is shown in figure 6.8. According to this flow chart, baseline power generation emissions should be calculated using Module BE5, and project power generation emissions should be calculated using Module PE6.

Step 4: Calculate Baseline Power Generation Emissions for the T&D Projects

Module BE5: Emissions from Importing Grid. The baseline emissions from the importing grid are calculated as follows:

$$BE_5 = \sum_{y=1}^{n}(IET_{m,y} \times EF_{CM,m})$$

Parameter	Unit	Value
$EF_{CM,m}$	tCO_2/MWh	0.6545
IET_m	MWh	106,672,377
BE_5		69,817,071

Note that IET_m is the sum of all of the years of the project life, and is the value that would be measured at the receiving substation, net of technical losses on the transmission line.

Step 5: Calculate Project Power Generation Emissions for the T&D Projects

Module PE6: Emissions from Identified New Source of Supply for Export. The new cross-border transmission line is linked to the construction of a new hydropower plant in Ethiopia (Gilbel Gibe III). Therefore, the source of incremental supply is identified as being this new plant with an emission factor of 0 tCO_2/MWh.

The emissions from the exporting grid are calculated as follows:

$$PE_6 = \sum_{y=1}^{n}(IET_{m,y} \times EF_{AS})/(1 - TL_{IC})$$

Parameter	Unit	Value
$EF_{AS,x}$	tCO_2/MWh	0
IET_m	MWh	106,672,377
PE_6		0

Note that IET_m is the sum of all the years of the project life, and is the value that would be measured at the receiving substation, net of technical losses on the transmission line.

Step 6: Summarize GHG Emissions Impacts

Table 7.1 presents a summary of the estimated GHG impacts from this project.

The table indicates that the project results in a very significant reduction in power generation emissions over the period 2012–27 because of indirect generation impacts (–69.8 $MtCO_2$). The results also show that although direct nongeneration emissions are significant—the highest of all three case studies—they are by far outweighed by the impacts on generation emissions. For this project, direct nongeneration emissions represent approximately 1 percent of the impact on generation emissions.

Table 7.1: Summary of GHG Impacts for Ethiopia-Kenya Power Systems Interconnection Project (tCO_2)

Direct nongeneration impacts			
Embodied emissions	n.a.		
Energy in construction	n.a.		
Land clearing	554,400		
SF_6	249,971		
	Baseline	**Project**	**Net**
Direct generation impacts			
Technical loss reduction	n.a.	n.a.	
Indirect generation impacts			
Increased reliability	n.a.	n.a.	
Capacity expansion	n.a.	n.a.	
Electrification	n.a.	n.a.	
Cross-border trade	69,817,071	0	–69,817,071

Source: Authors' analysis.

Note: n.a. = not applicable.

Case Study 2: Energy Access Scale-Up Program, Kenya

The Energy Access Scale-Up Program is an operation that contributes to Kenya's effort to improve and expand electricity services to the country. The loan includes components that support investments in all segments of the electricity chain: generation, T&D, and increased access. The GHG accounting for this case study focused on the transmission component. This component supports the government's plan to expand transmission capacity to serve growing demand from the distribution sector and to improve the reliability of the electricity network. This network is highly radial, which is characteristic of countries with low electrification rates.

The government plan consists of 13 subprojects on the 132/33 kV transmission Kenya Power and Light network. The projects in the plan have been developed by the network with the help of an external consultant and put forward for Bank financing. During the preparation of this report, two of the projects completed their technical, economic, financial, and environmental and social feasibility analyses.

Kisii-Awendo Line: This project will involve construction of a 44 km 132 kV transmission line between the proposed Kisii 132/33 kV substation and a 132/33 kV, 1x23 MVA substation to be built in the vicinity of Awendo, and the construction of a 132 kV line bay at Kisii.

Eldoret-Kitale Line: This project will involve construction of approximately 60 km of 132 kV single circuit transmission line, including establishment of a 132/33 kV, 23 MVA substation at Kitale. The 33 kV network that will be influenced by this project is the 33 kV radial from 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, most concentrated between Moi Barracks and Moi's Bridge.

Description of Projects and Data Availability

Project I: Kisii-Awendo Line

The relevant data for this subproject were sourced from the feasibility study prepared by Snowy Mountains Engineering Corporation and dated April 2009.

Step 1: Determine Which Direct Nongeneration Emissions Will Be Included

The table below determines which direct nongeneration emissions calculation modules apply to this project.

Question	Answer
Are data available on materials consumption by the T&D project and on the origin of those materials?	No
Are data available on energy consumption during the construction phase of the T&D project?	No
Does the T&D project involve clearing any land?	Yes (Apply Module D3: Land Clearing Emissions)
Does the T&D project include new lines or capacity expansion that includes new SF_6-containing equipment?	No

Step 2: Calculate Direct Nongeneration Emissions for the T&D Projects

Module D3: Land Clearing Emissions. The FSR makes no mention of the right of way for the new 132 kV/33 kV line, so the default figure of 30 m, based on discussions and feedback from World Bank staff, is applied, which, combined with the distance of 44 km, gives an area of 132 ha. With respect to the potential emissions from land clearing, an assumption has been made from information available in the environmental and social impact assessment that the land can be described as "Cropland—Annual crops" according to the IFC CEET table, and the relevant biomass density has therefore been applied.

The results for this module are summarized below:

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

Parameter	Unit	Value
A_{def}	ha	132
BD	tCO_2/ha	17
PE_{LC}		2,244

Module D4: SF_6 Emissions. Because the new equipment will displace old equipment that is being retired, there should be no net increase in SF_6 emissions.

Step 3: Determine How Baseline and Project Emissions from Power Generation Should Be Calculated

This project leads to technical loss reductions, increased reliability, and T&D capacity expansion. The decision trees for these three project types are presented in figures 6.4–6.6, respectively. For technical loss reduction baseline emissions should be calculated using Module BE2, and project emissions should be calculated using Module PE2. For increased reliability and T&D capacity expansion, baseline emissions should be calculated using Module BE4, and project emissions should be calculated using Module PE4.

Note that because both increased reliability and capacity expansion use Module PE4 (emissions from the project grid) but have different quantities of incremental electricity supplied, Module PE4 must be applied separately to each project objective. The same equations are thus used for each of these three impacts, but with different input parameters for total incremental electricity.

Step 4: Calculate Baseline Power Generation Emissions for the T&D Projects

Technical Loss Reduction

Module BE2: Emissions from Existing Technical Loss Rate. The feasibility study does not provide figures on technical losses for each year, but rather provides figures on annual technical loss reductions in MWh for the period 2012–32. It is therefore not possible to resolve this module as described, but the same result will be achieved by using the figures provided for technical loss as technical losses for the baseline, and assuming technical losses in the project scenario to be zero.

The results for this module are summarized here:

$$BE_2 = \sum_{y=1}^{n}(TL_{BL,y} \times EF_{CM})$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545

Year	$TL_{BL,y}$	BEy
	MWh	tCO_2
2012	2,312	1,513
2013	2,471	1,617
2014	2,562	1,677
2015	2,777	1,818
2016	2,978	1,949
2017	3,107	2,033
2018	3,349	2,192
2019	3,493	2,286
2020	3,780	2,474
2021	4,068	2,662
2022	4,257	2,786
2023	4,753	3,111
2024	5,653	3,700
2025	6,615	4,329
2026	7,705	5,043
2027	8,753	5,729
2028	9,786	6,405
2029	10,805	7,072
2030	11,815	7,733
2031	12,818	8,390
2032	13,784	9,021
BE2		**83,541**

Increased Reliability

Module BE4: No Emissions in the Baseline. Because there is no source of alternative energy specified in the project documentation, the assumption is made that there would be no power consumption in the absence of the project (BE4 = 0).

T&D Capacity Expansion

Module BE4: No Emissions in the Baseline. Because there is no source of alternative energy specified in the project documentation, the assumption is made that there would be no power consumption in the absence of the project (BE4 = 0).

Electrification

Although the FSR mentions electrification, there are no data in the feasibility studies on the incremental energy supplied to new customers by electrification. Thus, the technical and economic assessment assumed that all additional capacity would be used to supply the incremental demand of existing consumers. For this reason, this module is not applied.

Step 5: Calculate Project Power Generation Emissions for the T&D Projects

Technical Loss Reduction

Module PE2: Emissions from Expected Project Loss Rates. Because the FSR only provides data on total loss reduction, this module is not necessary. Project losses are zero and baseline losses represent the full benefit of the loss reduction.

Increased Reliability

Module PE4: Emissions from Project Grid. Annex D4 of the FSR provides tables that summarize the project's economic and financial reliability. The figures for financial reliability (which is defined as the net benefit resulting from the reconfigured system in net kWh added energy sales) provide an estimate of the additional power that can be sold to customers because of improved reliability. The figure presented in the FSR assumes 30 percent of the power provided through increased reliability is nonrecoverable; thus, this 30 percent must be taken into account (emissions reductions are independent of whether costs for provided electricity are recovered or not). The emission factor for the grid is from the Institute for Global Environmental Strategies (IGES) database for the grid emission factor (combined margin) for the Kenya grid.

$$PE_4 = \sum_{y=1}^{n}(IE_y \times EF_{CM})/(1 - IL)$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	2,149	1,407
2013	2,241	1,467
2014	2,310	1,512
2015	2,407	1,576
2016	2,476	1,621
2017	2,548	1,668
2018	2,649	1,733
2019	2,723	1,782
2020	2,794	1,828
2021	2,898	1,897
2022	2,976	1,948
2023	3,218	2,106
2024	3,450	2,258
2025	3,674	2,404
2026	3,849	2,519
2027	4,024	2,633
2028	4,197	2,747
2029	4,371	2,861
2030	4,546	2,975
2031	4,719	3,089
PE4		**42,032**

T&D Capacity Expansion

Module PE4: Emissions from Project Grid. Annex D4 of the FSR provides tables that summarize the project's economic and financial reliability. The table provides figures for customer consumption growth (also called financial growth). These figures are required to estimate additional project emissions caused by expansion of T&D capacity. The emission factor for the Kenya grid is taken from the IGES database. The data and results for this module are summarized below:

$$PE_4 = \sum_{y=1}^{n}(IE_y \times EF_{CM})/(1 - IL)$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	266	174
2013	538	352
2014	1,097	718
2015	1,678	1,098
2016	2,283	1,494
2017	2,912	1,906
2018	3,566	2,334
2019	4,246	2,779
2020	4,954	3,242
2021	5,690	3,724
2022	6,455	4,225
2023	6,649	4,352
2024	6,848	4,482
2025	7,054	4,617
2026	7,265	4,755
2027	7,483	4,898
2028	7,708	5,045
2029	7,939	5,196
2030	8,177	5,352
2031	8,422	5,512
PE4		**66,255**

Step 6: Summarize GHG Emissions Impacts

Table 7.2 presents a summary of the estimated GHG impacts from this project.

Table 7.2: Summary of GHG Impacts for Kisii-Awendo Line (tCO_2)

Direct nongeneration impacts			
Embodied emissions	n.a.		
Energy in construction	n.a.		
Land clearing	2,244		
SF_6	n.a.		
	Baseline	**Project**	**Net**
Direct generation impacts			
Technical loss reduction	83,541	0	−83,541
Indirect generation impacts			
Increased reliability	0	42,032	42,032
Capacity expansion	0	66,255	66,255
Electrification	n.a.	n.a.	
Cross-border trade	n.a.	n.a.	

Source: Authors' analysis.

Note: n.a. = not applicable.

Project II: Eldoret-Kitale Line

The relevant data for this project were sourced from the feasibility study prepared by Norconsult and dated September 2009 as part of the project preparation technical and economic analysis.

Step 1: Determine Which Direct Nongeneration Emissions Will Be Included

The following table determines which direct nongeneration emissions calculation modules apply to this project.

Question	Answer
Are data available on materials consumption by the T&D project and on the origin of those materials?	No
Are data available on energy consumption during the construction phase of the T&D project?	No
Does the T&D project involve clearing any land?	Yes (Apply Module D3: Land Clearing Emissions)
Does the T&D project include new lines or capacity expansion that includes new SF_6-containing equipment?	Yes (Apply Module D4: SF_6 Emissions)

Step 2: Calculate Direct Nongeneration Emissions for the T&D Projects

Module D3: Land Clearing Emissions. The FSR 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 FSR that the land can be described as "Cropland—Tropical (moist region), perennial woody biomass" according to the IFC CEET table; the relevant biomass density has therefore been applied. The results for this module are summarized below:

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

Parameter	Unit	Value
A_{def}	ha	180
BD	tCO_2/ha	77
PE_{LC}		13,860

Module D4: SF_6 Emissions. This case study was the only one for which data were available, which provided an indication of the number of SF_6-containing equipment that would be installed during project implementation and their respective capacities. Therefore, it was possible to use Option C to estimate GHG emissions from SF_6-containing equipment use. The project documentation stated that seven units would be installed that could be considered sealed-pressure SF_6-containing equipment and six units would be installed that could be considered closed-pressure SF_6-containing equipment. For disposal emissions, it has been assumed that all of the SF_6 will be recovered, because World Bank projects must follow strict environmental guidelines.

Parameter	Unit	Value
N_{SP}	no units	7
N_{CP}	no units	6
$ACap_{SP}$	t SF_6	0.005
$ACap_{CP}$	t SF_6	0.1
$EF_{SF_6,Use,SP}$	%	0.2%
$EF_{SF_6,Use,CP}$	%	2.6%
GWP_{SF_6}	tCO_2e/t SF_6	23,900
EL_{SF_6}	years	20
$PE_{SF_6,y}$	tCO_2e	375
$PE_{SF_6,tot}$	tCO_2e	7,490

Because the new equipment will displace old equipment that is being retired, there should be no net increase in SF_6 emissions. For this reason, SF_6 emissions have not been included in the summary.

Step 3: Determine How Baseline and Project Emissions from Power Generation Should Be Calculated

This project leads to technical loss reductions, increased reliability, T&D capacity expansion, and electrification. The decision trees for these four project types are presented in figures 6.4–6.7, respectively. For technical loss reduction, baseline emissions should be calculated using Module BE2 and project emissions using Module PE2. For increased reliability and T&D capacity expansion, baseline and project emissions should use Modules BE4 and PE4, respectively. For electrification, baseline and project emissions should use Modules BE3 and PE4, respectively.

Because increased reliability, capacity expansion, and electrification all use Module PE4 (emissions from the project grid) but have different quantities of incremental electricity supplied, Module PE4 must be applied separately to each project objective. In other words, the same equations are used for each of these three impacts, but with different input parameters for total incremental electricity.

Step 4: Calculate Baseline Power Generation Emissions for the T&D Projects

Technical Loss Reduction

Module BE2: Emissions from Existing Technical Loss Rate. The feasibility study does not provide figures on technical losses for each year, but rather on annual technical loss reductions in MWh for a 20-year period (2,900 MWh/year). This is incorporated into the model by designating this amount as the baseline losses and setting project losses to zero.

The results for this module are summarized below:

$$BE_2 = \sum_{y=1}^{n} (TL_{BL,y} \times EF_{CM})$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545

Year	$TL_{BL,y}$	BEy
	MWh	tCO_2
2012	2,900	1,898
2013	2,900	1,898
2014	2,900	1,898
2015	2,900	1,898
2016	2,900	1,898
2017	2,900	1,898
2018	2,900	1,898
2019	2,900	1,898
2020	2,900	1,898
2021	2,900	1,898
2022	2,900	1,898
2023	2,900	1,898
2024	2,900	1,898
2025	2,900	1,898
2026	2,900	1,898
2027	2,900	1,898
2028	2,900	1,898
2029	2,900	1,898
2030	2,900	1,898
2031	2,900	1,898
BE2		**37,961**

Increased Reliability

Module BE4: No Emissions in the Baseline. Because there is no source of alternative energy specified in the project documentation, the assumption is made that there would be no power consumption in the absence of the project (BE4 = 0).

T&D Capacity Expansion

Module BE4: No Emissions in the Baseline. Because there is no source of alternative energy specified in the project documentation, the assumption is made that there would be no power consumption in the absence of the project (BE4 = 0).

Electrification

Module BE3: Diesel Generator Emissions. The FSR identifies the cost of small-scale diesel as the alternative to the electrification project, so the emission factor for a diesel generator has been used.

The results for this module are summarized below:

$$BE_3 = \sum_{y=1}^{n} (IE_y \times EF_{AE})$$

Parameter	Unit	Value
EF_{AE}	tCO_2/MWh	0.8

Year	IE_y	BEy
	MWh	tCO_2
2012	3,350	2,680
2013	5,200	4,160
2014	7,250	5,800
2015	9,500	7,600
2016	11,950	9,560
2017	14,600	11,680
2018	17,450	13,960
2019	20,600	16,480
2020	24,050	19,240
2021	27,800	22,240
2022	31,850	25,480
2023	36,300	29,040
2024	41,150	32,920
2025	46,450	37,160
2026	52,250	41,800
2027	58,550	46,840
2028	65,450	52,360
2029	73,000	58,400
2030	81,200	64,960
2031	90,200	72,160
BE3		**574,520**

Step 5: Calculate Project Power Generation Emissions for the T&D Projects

Technical Loss Reduction

Module PE2: Emissions from Expected Project Loss Rates. Because the FSR only provides data on total loss reduction, this module is not necessary. Project losses are zero, and baseline losses represent the full benefit of the loss reduction.

Increased Reliability

Module PE4: Emissions from Project Grid. The feasibility study includes a table that summarizes the main operating parameters for the project's economic analysis. From this table, a figure of 1,900 MWh annual loss reduction is derived. "Annual loss reduction" in this context means reduction of financial losses in the form of lost MWh because of improved reliability. The emission factor used is from the IGES database for the grid emission factor (combined margin) for the Kenya grid. The results for this module are summarized below:

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	1,900	1,244
2013	1,900	1,244
2014	1,900	1,244
2015	1,900	1,244
2016	1,900	1,244
2017	1,900	1,244
2018	1,900	1,244
2019	1,900	1,244
2020	1,900	1,244
2021	1,900	1,244
2022	1,900	1,244
2023	1,900	1,244
2024	1,900	1,244
2025	1,900	1,244
2026	1,900	1,244
2027	1,900	1,244
2028	1,900	1,244
2029	1,900	1,244
2030	1,900	1,244
2031	1,900	1,244
PE4		**26,115**

T&D Capacity Expansion

Module PE4: Emissions from Project Grid. The feasibility study includes a table that summarizes the main operating parameters for the project's economic analysis. The table provides figures on incremental energy supplied to customers after grid extension, which increases from 6.7 GWh in 2012 to 180 GWh in 2031. However, the study does not clarify whether incremental energy supply is for connection of new consumers to the electricity grid (that is, electrification) or for supplying additional power generation to existing consumers where there is no alternative source of supply for these consumers. To test the modeling tool, it has been assumed that 50 percent of the incremental energy will be for capacity expansion and 50 percent for electrification. The critical difference here is not in project emissions, since Module PE4 would be the same for either project type. Rather, the difference is that the baseline alternative for electrification is diesel generators.

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	3,350	2,193
2013	5,200	3,403
2014	7,250	4,745
2015	9,500	6,218
2016	11,950	7,821
2017	14,600	9,556
2018	17,450	11,421
2019	20,600	13,483
2020	24,050	15,741
2021	27,800	18,195
2022	31,850	20,846
2023	36,300	23,758
2024	41,150	26,933
2025	46,450	30,402
2026	52,250	34,198
2027	58,550	38,321
2028	65,450	42,837
2029	73,000	47,779
2030	81,200	53,145
2031	90,200	59,036
PE4		**470,029**

Electrification

Module PE4: Emissions from Project Grid. As explained above, 50 percent of the incremental energy supplied is assumed to be for electrification.

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.6545
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	3,350	2,193
2013	5,200	3,403
2014	7,250	4,745
2015	9,500	6,218
2016	11,950	7,821
2017	14,600	9,556
2018	17,450	11,421
2019	20,600	13,483
2020	24,050	15,741
2021	27,800	18,195
2022	31,850	20,846
2023	36,300	23,758
2024	41,150	26,933
2025	46,450	30,402
2026	52,250	34,198
2027	58,550	38,321
2028	65,450	42,837
2029	73,000	47,779
2030	81,200	53,145
2031	90,200	59,036
PE4		**470,029**

Step 6: Summarize GHG Emissions Impacts

Table 7.3 presents a summary of the estimated GHG impacts from this project.

Table 7.3: Summary of GHG impacts for Eldoret-Kitale Line (tCO_2)

Direct nongeneration impacts			
Embodied emissions	n.a.		
Energy in construction	n.a.		
Land clearing	13,860		
SF_6	7,490		
	Baseline	**Project**	**Net**
Direct generation impacts			
Technical loss reduction	37,961	0	–37,961
Indirect generation impacts			
Increased reliability	0	26,115	26,115
Capacity expansion	0	470,029	470,029
Electrification	574,520	470,029	–104,491
Cross-border trade	n.a.	n.a.	

Source: Authors' analysis.

Note: n.a. = not applicable.

Case Study 3: Eletrobras Distribution Rehabilitation Project, Brazil

The proposed project would strengthen the management, operations, and corporate governance of the six distribution companies managed by Eletrobras (Amazonas Energia, Eletroacre, Ceron, Boa Vista, Cepisa, and Ceal), through the following components and subcomponents.

- **Component 1**: Service Quality Improvement and Loss Reduction Program
  - Subtransmission and distribution network reinforcement
  - Advance metering infrastructure
  - Modernization of distribution company management information system
- **Component 2**: Institutional Strengthening

The subtransmission and distribution network reinforcement subcomponent aims to strengthen and rehabilitate the subtransmission and distribution grid, including 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 include distribution equipment for the supervisory control, voltage control, and switching needed to improve the reliability and quality of the electricity supply. This subcomponent, which would represent the bulk of the project investment, would help 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). It is this subcomponent that will lead to the impacts on emissions evaluated here.

The relevant data for this project was sourced from a number of World Bank documents, including the project concept note dated August 2009, the investment analysis spreadsheets dated September 2009, and the World Bank project appraisal document dated January 2009. No consultant feasibility study was made available for this project.

Description of Modules and Data Availability

Step 1: Determine Which Direct Nongeneration Emissions Will Be Included

The following table determines which direct nongeneration emissions calculation modules apply to this project.

Question	Answer
Are data available on materials consumption by the T&D project and on the origin of those materials?	No
Are data available on energy consumption during the construction phase of the T&D project?	No
Does the T&D project involve clearing any land?	No
Does the T&D project include new lines or capacity expansion that includes new SF_6-containing equipment?	No

None of the equipment to be installed will require additional right of ways, since the project will rehabilitate or strengthen existing distribution infrastructure only, and Module D3 is therefore not used. As this project involves only technical loss reduction and increased reliability, Module D4 (SF_6 Emissions) also does not apply because of the low-voltage level of the system. The project team confirmed with the distribution companies that SF_6 is not installed in low-voltage distribution lines, which is the main focus of the project.

Step 2: Calculate Direct Nongeneration Emissions for the T&D Projects

This step is not applicable, since none of the direct nongeneration emissions calculation modules apply to this project.

Step 3: Determine How Baseline and Project Emissions from Power Generation Should Be Calculated

This project leads to technical loss reduction and increased reliability. The decision trees for these project types are presented in figures 6.4 and 6.5, respectively. For technical loss reduction, baseline emissions should be calculated using Module BE2 and project emissions using Module PE2. For increased reliability, baseline and project emissions should use Modules BE4 and PE4, respectively.

Step 4: Calculate Baseline Power Generation Emissions for the T&D Projects

Technical Loss Reduction

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 (combined margin) for the Brazilian grid is also available from the IGES database (0.1045 tCO_2e/MWh).

The feasibility study does not provide figures on technical losses for each year, but rather provides figures on technical loss reductions in MWh for a 10-year period (5,464 GWh over 10 years). This information is incorporated into the model by designating this amount as the baseline losses and setting project losses to zero.

The results for this module are summarized below:

$$BE_2 = \sum_{y=1}^{n}(TL_{BL,y} \times EF_{CM})$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.1045

Year	$TL_{BL,y}$	BEy
	MWh	tCO_2
2012	546,400	57,099
2013	546,400	57,099
2014	546,400	57,099
2015	546,400	57,099
2016	546,400	57,099
2017	546,400	57,099
2018	546,400	57,099
2019	546,400	57,099
2020	546,400	57,099
2021	546,400	57,099
BE2		**570,988**

Increased Reliability

Module BE3: Emissions from Alternative Baseline Energy Source. The reduction in frequency and duration of interruptions in electricity supply because of improved service quality would result in an increase of electricity supply of 606.8 GWh over a 10-year period. Distribution company customers would be able to consume electricity during periods in which they currently experience interruptions in supply and abnormal voltage drops, thus resorting to reduced consumption or the use of alternative energy sources. The emission factors used are the default value for diesel generators taken from the CDM methodology AMS I.D. and from the IGES database. In this case study, it is assumed from country experience that only the medium- and high-voltage customers—which have been calculated to account for 43 percent of total consumption in the six distribution companies—will have access to alternative energy sources (diesel generator sets). Thus, for the baseline, 260.9 GWh (43 percent of 606.8 GWh) of the electricity supplied originates from the use of diesel generators (default value for diesel generators used). For the remainder of the electricity supplied (57 percent of 606.8 GWh), it is assumed that there would be no power consumption in the absence of the project (baseline BE4 = 0). The results for this module are summarized below:

$$BE_3 = \sum_{y=1}^{n}(IE_y \times EF_{AE})$$

Parameter	Unit	Value
EF_{AE}	tCO_2/MWh	0.8

Year	IE_y	BEy
	MWh	tCO_2
2012	26,092	20,874
2013	26,092	20,874
2014	26,092	20,874
2015	26,092	20,874
2016	26,092	20,874
2017	26,092	20,874
2018	26,092	20,874
2019	26,092	20,874
2020	26,092	20,874
2021	26,092	20,874
BE3		**208,736**

Step 5: Calculate Project Power Generation Emissions for the T&D Projects

Technical Loss Reduction

Module PE2: Emissions from Expected Project Loss Rates. As described above, technical losses in the project scenario are set to zero because all loss reductions are captured in the baseline.

Increased Reliability

Module PE4: Emissions from Project Grid. The results for this module are summarized below:

$$PE_4 = \sum_{y=1}^{n}(IE_y \times EF_{CM})/(1 - IL)$$

Parameter	Unit	Value
EF_{CM}	tCO_2/MWh	0.1045
IL	%	0

Year	IE_y	PEy
	MWh	tCO_2
2012	60,680	6,341
2013	60,680	6,341
2014	60,680	6,341
2015	60,680	6,341
2016	60,680	6,341
2017	60,680	6,341
2018	60,680	6,341
2019	60,680	6,341
2020	60,680	6,341
2021	60,680	6,341
PE4		**63,411**

Step 6: Summarize GHG Emissions Impacts

Table 7.4 presents a summary of the estimated GHG impacts from this project.

Table 7.4: Summary of GHG Impacts for Eletrobras Distribution Rehabilitation Project (tCO_2)

Direct nongeneration impacts			
Embodied emissions	n.a.		
Energy in construction	n.a.		
Land clearing	n.a.		
SF_6	n.a.		
	Baseline	**Project**	**Net**
Direct generation impacts			
Technical loss reduction	570,988	0	−570,988
Indirect generation impacts			
Increased reliability	208,736	63,411	−145,325
Capacity expansion	n.a.	n.a.	
Electrification	n.a.	n.a.	
Cross-border trade	n.a.	n.a.	

Source: Authors' analysis.

Note: n.a. = not applicable.

Summary of Results and Conclusions from the Three Case Studies

Table 7.5 summarizes the results from the three case studies presented above:

Some important conclusions on the feasibility of implementing the proposed approach can be gleaned from the three case studies. While the approach requires a certain amount of data analysis and processing, the additional effort will not drastically increase the effort required to perform economic and technical analysis. For a typical project component where two or three GHG estimation modules may be required, approximately three days are needed for data collection and setup plus a day of analysis. Some knowledge of GHG accounting will be required on the part of the analyst, especially to interpret the modules and understand the data requirements. For a typical Bank project, which may include one component in transmission and one in distribution, the total cost would be four days of work by a research analyst. Strong collaboration between this analyst and the project team—especially with those team members or consultants dealing with the economic and social and environmental evaluations of the projects—will be required in order to gather the data. Referring to this document, those team members performing the technical and economic evaluation should be able to conduct the analysis by themselves in the same number of days.

While current project preparation procedures already provide most of the data that will be important to estimate net impacts, some improved data collection will be needed, especially for the direct nongeneration emissions modules. Determining the type of incremental demand being served by the T&D project is also important for the correct application of some modules, such as electrification and capacity expansion. Some of the issues regarding data availability are further developed below.

Table 7.5: Summary Results for Three Case Studies (tCO_2)

			Case 2		
		Case 1	Project I	Project II	Case 3
Direct non-generation impacts	Embodied emissions	n.a.	n.a.	n.a.	n.a.
	Energy in construction	n.a.	n.a.	n.a.	n.a.
	Land clearing	554,400	2,244	13,860	n.a.
	SF_6	249,971	n.a.	n.a.	n.a.
Direct generation impacts	Technical loss reduction	n.a.	−83,541	−37,961	−570,988
Indirect generation impacts	Increased reliability	n.a.	42,032	26,115	−145,325
	Capacity expansion	n.a.	66,255	470,029	n.a.
	Electrification	n.a.	n.a.	−104,491	n.a.
	Cross-border trade	−69,817,071	n.a.	n.a.	n.a.

Source: Authors' analysis.

Note: A negative total represents a reduction in GHG emissions. Project I refers to the Kisii-Awendo transmission project; Project II refers to Eldoret-Kitale. n.a. = not applicable.

Embodied Emissions in Materials

This impact can only be evaluated where the project preparation documentation provides the necessary data. Data on materials that would be used during construction may be available only for large projects (for example, large transmission interconnectors). Such data are not usually collected for smaller projects (for example, distribution rehabilitation). The origin of materials is generally not known during the project preparation phase, but rather only after the construction contracts are awarded, according to Bank procurement rules. Emissions from energy use in construction have similar data collection needs.

Land Clearing

The impacts of land clearing can be estimated more easily. Information is usually available as part of the project's environmental and social analysis. If this information is not available, standard right-of-way widths can be used for each voltage level. The length of the line would almost always be available during project preparation. Vegetation type was not always available in the documentation provided, and was not described using the same classification as the IFC CEET table or other sources that provide emission factors for different vegetation types (for example, annex A, table A.1).

SF_6 Emissions

Data were not available on the nameplate capacity of the SF_6-containing equipment to be installed in most cases. This may be because such equipment is not installed for all T&D projects, especially for low-voltage distribution lines. When such equipment is installed, data on SF_6 capacity and leakage rates are not traditionally collected. A systemwide average SF_6 emission factor can be applied where project-specific equipment data are not available. This emission factor should reflect the fact that most SF_6 emissions will be from high-voltage equipment.

Technical Loss Reduction

Figures for technical loss reduction rates were available for most case studies, although the information was not always provided in the format used in the relevant module. This will not affect the accuracy of the results, as long as total reduction in losses is available in the project documentation.

Increased Reliability

In the two case studies where increased reliability is an important project component, relevant data on increased energy supply was available, so this module could be applied successfully. Energy demand not served because of reliability problems is a parameter input for most economic evaluations of T&D projects.

T&D Capacity Expansion and Electrification

The most challenging task in these two modules is to identify the type of incremental demand that will be served by the project. Project teams will need to differentiate between suppressed demand and demand that, in the absence of the project, will be supplied by alternative on-site electricity supply. Not all demand forecasts used in economic evaluation of distribution projects will make this distinction, which has an important impact on emissions as presented in the examples.

Cross-Border Trade

This module was only used for the first case study and did not pose any particular difficulties. International interconnector projects are likely to have power system and generation simulation scenarios that can provide most of the information required.

Project lifetimes of between 10 and 21 years were used in the economic analysis of the projects based on the information available in the feasibility studies. This lifetime may be appropriate, given the different technologies and equipment installed. For the proposed approach, the time frame for assessing GHG accounting should be consistent with that used for the economic analysis.

Nongeneration versus Generation Emissions

The three cases explored indicate that direct nongeneration emissions are relatively small compared to direct and indirect impacts on power generation. This is supported by evidence from the literature review. In all cases, direct nongeneration emissions range from 0 to 6 percent of generation impacts. The direct nongeneration emissions for the interconnection between Ethiopia and Kenya are estimated at +804 $ktCO_2$, largely from land clearing, while the indirect impact on power generation is estimated at −69,812 $ktCO_2$ because of the displacement of power from a higher emissions grid. For one of the transmission projects in Kenya, direct nongeneration emissions are estimated at +14 $ktCO_2$, while the direct generation impact is −38 $ktCO_2$ and the indirect generation impact is +392 $ktCO_2$. The T&D rehabilitation project in Brazil results in a direct generation impact of −571 $ktCO_2$ and an indirect generation impact of −145 $ktCO_2$, and has no direct nongeneration emissions.

8. Conclusions

The objective of this study was to review existing methodologies and to recommend feasible ones that capture the most relevant GHG impacts of T&D projects in the context of the World Bank project preparation cycle. The diversity and quantity of T&D interventions, their varied technical and economic impacts, and data availability at the time of project preparation emphasize the necessity of a flexible, modular approach. The study approach and conclusions are not intended to be the final word on T&D project GHG emissions accounting, but instead viewed as a starting point for accurately understanding the most important implications of T&D interventions using a framework that can be implemented credibly in the context of project preparation.

Importance of Net Emissions Accounting and Including Power Generation Emissions Impacts

The survey of methodologies and case studies indicate that direct nongeneration emissions for T&D projects are well covered by many existing approaches. There is broad consistency on the type of emissions that are relevant and how they can be estimated. In addition to data now being collected for technical and economic assessment of projects, some additional data are needed to estimate emissions. Direct nongeneration emissions from T&D projects are small when compared to the impacts of T&D projects on power generation emissions.

There is very little experience with the analysis of the effects of T&D projects on emissions from power generation. Several key project types have no accepted methodologies at all in the context of climate financing mechanisms such as the CDM, which underscores the importance of this study. The direct generation impacts of technical loss reduction and the indirect generation impacts of electrification are noted in several methodologies and international studies, including the World Bank's *GHG Assessment Handbook*. However, impacts such as increased reliability and T&D capacity expansion have not been analyzed for their GHG impacts. Cross-border trade, although discussed by several proposed CDM methodologies, also does not have an accepted standard of analysis.

One of the most important conclusions of this work is that the impacts of T&D projects on power generation emissions are likely to be much greater than direct nongeneration emissions. For some projects, the net emissions impacts could be negative; that is, the project contributes to reduced overall power system emissions even though direct nongeneration emissions are positive. Although this increases the level of effort required to assess the impacts on power generation, not analyzing the impacts on generation emissions could significantly underestimate the impact of T&D projects on GHG emissions.

Implementation Issues: Level of Effort, Data Collection, and Uncertainty

While the proposed approach is relatively simple and robust for estimating the most important GHG impacts of World Bank T&D interventions, this analysis will require some additional effort from project teams. For some projects, this effort will involve additional data collection; mainly, it will entail additional time in applying the modules. This assessment is based on the work entailed in screening the project appraisal documents listed in annex B and for the three case studies presented in chapter 7 and the projects under preparation used in this report to perform GHG accounting with the proposed approach. For a typical two-component project, the research and analysis required to perform GHG accounting using the proposed approach should take a research analyst a total of 8 days, working in coordination with the team members performing the technical and economic evaluation of the project.

Some data collection issues that project teams need to be aware of include the following:

- For direct nongeneration emissions accounting, the quantity of construction materials required for different projects is not usually known with certainty at the time of project preparation because the detailed feasibility studies have not yet been completed. The relatively small size of this impact would not merit additional effort by project teams.
- While land clearing is generally covered in the environmental and social impact assessments, the project documentation should clarify the IPCC-defined vegetation types so the correct emission factors can be used.
- Detailed data on equipment containing SF_6 is a gap that must be addressed, particularly for high-voltage equipment. Existing environmental and social safeguards require regulated handling of SF_6, but there is no requirement to quantify fugitive emissions or specify the characteristics of all equipment being installed.

The review of existing studies and the case studies indicate that direct nongeneration emissions from T&D projects are small relative to power generation emissions impacts. Erring on the high side of estimating direct nongeneration emissions is preferable to underestimating them. The best solution is to integrate the data collection process into the project preparation cycle.

Some limited additional data are needed to assess the impact on power generation emissions. The majority of these modules require some of the marginal grid emission factors. Although emission factors from the IGES CDM database or a registered CDM project can be used, project teams could consider collecting primary data from a national utility or similar source during project preparation. Projects that conduct a power generation simulation for their economic analysis will have this information. However, distribution and electrification projects generally will not collect such information.

An important challenge in assessing net impacts of increased reliability, technical loss reduction, and capacity expansion projects is the clear separation of the impacts of these objectives, both theoretically and practically. While load flow and long-term economic dispatch simulations could provide reliable information to supplement all the modules, they are not conducted for all types of projects. If the impacts on losses and reliability are determined separately, it is essential that the teams use consistent baselines and project scenarios. For instance, if the impact in losses of the project is estimated for an entire network, then the impact of the project on increased transmission capacity should also be analyzed for the entire network.

For capacity expansion projects and, to a lesser extent, electrification projects, an additional source of uncertainty is in the manner in which the baseline captures alternatives to the grid. In other words, if a capacity expansion project were not implemented, would the customers find other equivalent power sources? This is both a question of principle and of practice. The principle issue is that economic development will drive the need for more power, and must be provided by the grid or by other sources. Even if those alternatives are not currently in place, to exclude them from the baseline would be in essence to assume that the demand for power is not growing. At the same time, the reality is that the lack of power is a major constraint to development, and there are many large industrial projects that would not be implemented without significant T&D capacity expansion. The practical issue is whether the project's technical and economic analysis provides information on how electricity demand will be supplied if the project is not implemented. Uncertainty is always present in project evaluation and will affect the credibility of the baseline and project scenarios. The approach should be consistent and applicable to current project preparation practices. Thus, if alternative power sources have been identified in a project's technical and economic assessment, they should be used to define the baseline emissions. A zero emissions baseline should be assumed if no alternative source is identified.

For cross-border trade projects where load flow and long-term dispatch modeling data exist, estimating emissions impacts is straightforward. This is likely to be the case for some large interconnector projects, but certainly not for all. Where these data are not available, the challenge is to determine whether the use of marginal emission factors for the grid accurately represents the impacts on dispatch caused by the project. The answer to this will depend on the dispatch systems used for both grids, their level of integration, and the grid characteristics. Using marginal grid emission factors is feasible and in line with some of the proposed CDM methodologies, but sacrifices a certain level of accuracy.

For electrification, the main challenge lies in addressing the displacement of fuels other than electricity. All the existing methodologies only look at the displacement of alternative forms of electricity by grid power installed. This is even true of the small-scale CDM methodologies applied to renewable energy systems for individual households. While electricity will clearly displace some other energy sources, such as kerosene use for lighting, the quantity displaced, the time frame, and the displacement conditions are complex issues that need significant attention. The World Bank is undertaking additional work on this important subject.

Lessons for the Bank's Overall Effort on GHG Accounting under the SFDCC

This study has shown that simple, feasible, and credible methodologies for direct nongeneration impacts and generation emissions impacts of T&D interventions can be applied to World Bank projects. While the Bank's interventions differ significantly from private sector transactions and traditional CDM projects, the existing project preparation cycle and formal requirements for technical, economic, and environmental analysis of projects provide a good starting platform for GHG accounting in the T&D sector. Implementing GHG accounting with the proposed approach does not present a major burden to project teams, although certain data collection issues do need to be addressed.

The review and results obtained emphasize the importance of the T&D infrastructure sector in achieving lower-carbon development paths in the power sector, which has historically been largely overlooked. The T&D sector is particularly significant in World Bank operations in client countries where losses are high or electricity systems are weak and relatively small. An efficient and integrated grid can enable large-scale investment in clean technologies and increase the operational efficiency of existing power generation sources, potentially reducing emissions. In electricity systems where reliability is low and technical losses in the T&D sector are high, T&D investments can have major impacts on low-carbon growth.

As some of the case studies show, a reliable and efficient transmission system can contribute to the fulfillment of the twin objectives of efficient and reliable energy supply and a contribution to reduced emissions. This is especially true in situations where low reliability and losses lead to wasteful use of power generation sources and therefore to increased emissions. It is also true where transmission systems in developing and developed countries are challenged by the need to connect more renewable energy sources. The transmission system will be an important enabler to ensure that the power sector can move toward lower-carbon power generation options. This work provides a platform to estimate the GHG impacts of T&D projects and contributes to the ongoing work on low-carbon development planning being undertaken at the World Bank.

The SFDCC clearly states that GHG accounting is an analytical exercise and should not be used as a decision-making tool for Bank-financed projects. The purpose of this effort is to increase knowledge and capacity building, understand the implications of new approaches on GHG accounting, and facilitate the use of emerging climate financing funds. This work has also aimed at increasing knowledge and understanding of the implications of new approaches and Bank interventions. The formal adoption of GHG accounting procedures for Bank operations may require some uniformity and consistency across all sectors. As the work on piloting GHG accounting in other sectors moves forward, a Bank-wide proposal on GHG analysis should be proposed to the Board as envisaged by the SFDCC.

The proposed approach has been designed to suit the structure of Bank projects that contain T&D components that can be categorized as subsectoral programs and not discrete projects, such as many carbon financing transactions. The move toward more comprehensive or sector-based approaches by climate financing mechanisms is increasingly being recognized as a possible solution to the drawbacks of project-based climate financing mechanisms (Bodansky 2007; CCAP 2008).

Annex A: Data Tables for Methodology Proposals

Table A.1: Carbon Density in Biomass Types

Type of tree (Please select from drop-down list)	(B) Above-ground biomass (t dry matter/ha)	(C) Above-ground biomass (t C/ha = AxB)	(E) Below/above ground ratio (t d.m.)	(F) Below-ground biomass (t C/ha = CxE)	Carbon fraction (t C/t dry matter)
Natural Forest—Tropical (avg)	164.0	77.1	0.34	25.9	0.47
Natural Forest—Tropical rainforest	300	141.0	0.37	52.2	0.47
Natural Forest—Tropical moist deciduous	180	84.6	0.22	18.6	0.47
Natural Forest—Tropical dry	130	61.1	0.42	25.7	0.47
Natural Forest—Tropical shrubland	70	32.9	0.40	13.2	0.47
Natural Forest—Tropical mountain systems	140	65.8	0.27	17.8	0.47
Natural Forest—Subtropical (avg)	140	65.8	0.32	21.1	0.47
Natural Forest—Subtropical humid	220	103.4	0.22	22.7	0.47
Natural Forest—Subtropical dry	130	61.1	0.42	25.7	0.47
Natural Forest—Subtropical steppe	70	32.9	0.32	10.5	0.47
Natural Forest—Subtropical mountain systems	140	65.8	n.a.	n.a.	0.47
Natural Forest—Temperate (avg)	133.3	62.7	0.25	15.5	0.47
Natural Forest—Temperate oceanic	180	84.6	0.22	18.6	0.47
Natural Forest—Temperate continental	120	56.4	0.26	14.7	0.47
Natural Forest—Temperate mountain systems	100	47.0	0.26	12.2	0.47
Natural Forest—Boreal (avg)	31.7	14.9	0.39	5.8	0.47
Natural Forest—Boreal coniferous	50	23.5	0.39	9.2	0.47
Natural Forest—Boreal tundra woodland	15	7.1	0.39	2.7	0.47
Natural Forest—Boreal mountain systems	30	14.1	0.39	5.5	0.47

Type of tree (Please select from drop-down list)	(B) Above-ground bio-mass (t dry matter/ha)	(C) Above-ground bio-mass (t C/ha = AxB)	(E) Below/above ground ratio (t d.m.)	(F) Below-ground bio-mass (t C/ha = CxE)	Carbon fraction (t C/t dry matter)
Plantation Forest—Tropical (avg)	90.0	42.3	0.34	14.2	0.47
Plantation Forest—Tropical rain forest	150	70.5	0.37	26.1	0.47
Plantation Forest—Tropical moist deciduous forest	120	56.4	0.22	12.4	0.47
Plantation Forest—Tropical dry forest	60	28.2	0.42	11.8	0.47
Plantation Forest—Tropical shrubland	30	14.1	0.40	5.6	0.47
Plantation Forest—Tropical mountain systems	90	42.3	0.27	11.4	0.47
Plantation Forest—Subtropical (avg)	80.0	37.6	0.32	12.0	0.47
Plantation Forest—Subtropical humid forest	140	65.8	0.22	14.5	0.47
Plantation Forest—Subtropical dry forest	60	28.2	0.42	11.8	0.47
Plantation Forest—Subtropical steppe	30	14.1	0.32	4.5	0.47
Plantation Forest—Subtropical mountain systems	90	42.3	0.00	n.a.	0.47
Plantation Forest—Temperate (avg)	120.0	56.4	0.25	13.9	0.47
Plantation Forest—Temperate oceanic forest	160	75.2	0.22	16.5	0.47
Plantation Forest—Temperate continental forest	100	47.0	0.26	12.2	0.47
Plantation Forest—Temperate mountain systems	100	47.0	0.26	12.2	0.47
Plantation Forest—Boreal (avg)	28.3	13.3	0.39	5.2	0.47
Plantation Forest—Boreal coniferous forest	40	18.8	0.39	7.3	0.47
Plantation Forest—Boreal tundra woodland	15	7.1	0.39	2.7	0.47
Plantation Forest—Boreal mountain systems	30	14.1	0.39	5.5	0.47
Cropland—Temperate (all regions), woody biomass	n.a.	63	n.a.	n.a.	0.47
Cropland—Tropical (dry region), perennial woody biomass	n.a.	9	n.a.	n.a.	0.47
Cropland—Tropical (moist region), perennial woody biomass	n.a.	21	n.a.	n.a.	0.47
Cropland—Tropical (wet region), perennial woody biomass	n.a.	50	n.a.	n.a.	0.47
Cropland—Annual crops (all)	10	4.7	n.a.	n.a.	0.5
Grassland—Boreal (dry and wet)	1.7	0.68	4.0	1.6	0.4
Grassland—Cold Temperate (dry)	1.7	0.68	2.8	1.1	0.4

Type of tree (Please select from drop-down list)	(B) Above-ground biomass (t dry matter/ha)	(C) Above-ground biomass (t C/ha = AxB)	(E) Below/above ground ratio (t d.m.)	(F) Below-ground biomass (t C/ha = CxE)	Carbon fraction (t C/t dry matter)
Grassland—Cold Temperate (wet)	2.4	0.96	4.7	1.9	0.4
Grassland—Warm Temperate (dry)	1.6	0.64	2.8	1.1	0.4
Grassland—Warm Temperate (wet)	2.7	1.08	4.0	1.6	0.4
Grassland—Tropical (dry)	2.3	0.92	2.8	1.1	0.4
Grassland—Tropical (moist and wet)	6.2	2.48	1.6	0.6	0.4
Settlement—Construction	n.a.	n.a.	n.a.	n.a.	n.a.

Source: IPCC 2006.

Note: Entries in blue are an average of IPCC values. n.a. = not applicable.

Table A.2: Default Emission Factors for Generator Systems in Small-Scale Diesel Power Plants for Three Load Factor Levels (kg CO_2e/kWh)

Case	Load factor (%)		
	Minigrid with 24-hour service (25%)	Minigrid with temporary service (4–6 hr/day; productive applications; water pumps) (50%)	Minigrid with storage (100%)
< 15 kW	2.4	1.4	1.2
≥ 15 < 35 kW	1.9	1.3	1.1
≥ 35 < 135 kW	1.3	1.0	1.0
≥ 135 < 200 kW	0.9	0.8	0.8
> 200 kW[a]	0.8	0.8	0.8

Source: UNFCCC 2009a.

Note: A conversion factor of 3.2 kg CO_2 per kg of diesel has been used (following revised 1996 *IPCC Guidelines for National Greenhouse Gas Inventories*). Values are derived from fuel curves in the online manual of RETScreen International's PV 2000 model, downloadable from http://retscreen.net/.

a. Default values.

Table A.3: Default Energy Efficiencies of Different Power Plant Types (%)

Power plant type	Old (before 2000)	New (after 2000)
Coal		
Subcritical	37	39
Supercritical		45
Ultrasupercritical		50
IGCC		50
FBS	35.5	
CFBS	36.5	40
PFBS		41.5
Oil		
Steam turbine	37.5	39
Open cycle	30	39.5
Combined cycle	46	46
Natural gas		
Steam turbine	37.5	37.5
Open cycle	30	39.5
Combined cycle	46	60

Source: UNFCCC 2009e.

Annex B: World Bank T&D Projects

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2003	P063913	ID-Java-Bali Pwr Sector & Strength	EAP	Indonesia	IDA	99.09	P063913
2003	P043311	Power Development Project	SAR	Nepal	IDA	26.55	P043311
2004	P083908	Emergency Power Rehabilitation Project	SAR	Afghanistan	IDA	84.75	P083908
2004	P064844	KH-Rural Electrif. & Transmn	EAP	Cambodia	IDA	16.97	P064844
2004	P069183	MZ—Energy Reform and Access SiL (FY2004)	AFR	Mozambique	IDA	30.60	P069183
2004	P066532	PH-GEF-Electric Cooprtv System Loss Redu	EAP	Philippines	GEF	12.00	P066532
2005	P094735	Emerg National Solidarity—Supplemental	SAR	Afghanistan	IDA	5.60	P094735
2005	P075994	3A-WAPP Phase 1 APL 1 (FY2005)	AFR	AFR Region	IDA	40.00	P075994
2005	P090656	ECSEE APL2 (Albania)	ECA	Albania	IDA	27.00	P090656
2005	P083341	Power Transmission	ECA	Azerbaijan	IDA	48.00	P083341
2005	P079633	BJ-Energy Srvc Delivery APL (FY2005)	AFR	Benin	IDA	28.80	P079633
2005	P076807	CL-Infrastructure for Territorial Dvlpmt	LCR	Chile	IBRD	4.52	P076807
2005	P088619	CD-Emergen Living Conditions Impr (FY2005)	AFR	Congo, Dem. Rep.	IDA	12.30	P088619
2005	P082712	DO Power Sector Program Loan	LCR	Dominican Republic	IBRD	150.00	P082712

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2005	P057929	ER-Power Distribution SIL (FY2005)	AFR	Eritrea	IDA	45.00	P057929
2005	P083131	KE-Energy Sec Recovery Prj (FY2005)	AFR	Kenya	IDA	68.00	P083131
2005	P090194	RW-Urgent Electricity Rehab SIL (FY2005)	AFR	Rwanda	IDA	3.00	P090194
2005	P073477	SN-Elec Sec Effi. Enhanc. Phase 1 APL-1	AFR	Senegal	IDA	8.60	P073477
2005	P085708	SN-Elec. Serv. for Rural Areas (FY2005)	AFR	Senegal	IDA	17.04	P085708
2005	P088867	ECSEE APL #2 (Serbia)	ECA	Serbia	IBRD	21.00	P088867
2005	P087203	SL-Power & Water SIL (FY2005)	AFR	Sierra Leone	IDA	15.40	P087203
2005	P094176	ECSEE APL #2 (Turkey) (CRL)	ECA	Turkey	IBRD	66.00	P094176
2005	P074688	VN-Rural Energy 2	EAP	Vietnam	IDA	220.00	P074688
2006	P094917	3A-WAPP APL 1 (CTB Phase 2) Project	AFR	AFR Region	IDA	3.00	P094917
2006	P094917	3A-WAPP APL 1 (CTB Phase 2) Project	AFR	AFR Region	IDA	27.00	P094917
2006	P094917	3A-WAPP APL 1 (CTB Phase 2) Project	AFR	AFR Region	IDA	27.00	P094917
2006	P090666	ECSEE APL3-BiH	ECA	Bosnia and Herzegovina	IDA	36.00	P090666
2006	P093787	BR Bahia State Integ Proj Rur Pov	LCR	Brazil	IBRD	8.70	P093787
2006	P052256	BR-MG Rural Poverty Reduction	LCR	Brazil	IBRD	8.75	P052256
2006	P096305	CD-Emerg MS Rehab & Recov ERL Sup (FY2006)	AFR	Congo, Dem. Rep.	IDA	10.00	P096305
2006	P086379	DJ-Power Access And Diversification	MNA	Djibouti	IDA	1.54	P086379
2006	P097271	ET-Electricity Access (Rural) Expansion	AFR	Ethiopia	IDA	130.73	P097271
2006	P097975	GW-MS Infrastructure Rehab SIM (FY2006)	AFR	Guinea-Bissau	IDA	6.00	P097975
2006	P086775	HN (CRL1) Rural Infrastructure Project	LCR	Honduras	IDA	3.76	P086775

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2006	P086414	Power System Development Project III	SAR	India	IDA	400.00	P086414
2006	P091299	JM Inner City Basic Services Project	LCR	Jamaica	IBRD	1.47	P091299
2006	P095155	N-S Elec Transm	ECA	Kazakhstan	IBRD	100.00	P095155
2006	P100160	LR-Emergency Infrastructure ERL (FY2006)	AFR	Liberia	IBRD	2.70	P100160
2006	P082337	ECSEE APL #3 (Macedonia, FYR)	ECA	Macedonia, FYR	IBRD	25.00	P082337
2006	P057761	MW-Infrastr Srvcs SIM	AFR	Malawi	IDA	5.20	P057761
2006	P096598	ECSEE APL #3—Montenegro	ECA	Montenegro	IBRD	1.71	P096598
2006	P090104	NG-Natl Energy Dev SIL (FY2006)	AFR	Nigeria	IDA	146.20	P090104
2006	P088181	TP Consolidation Support Program (CSP) 1	EAP	Timor-Leste	IDA	0.07	P088181
2006	P096400	ECSEE APL #3 (Turkey)	ECA	Turkey	IBRD	150.00	P096400
2006	P084871	VN-Trans & Distrib 2	EAP	Vietnam	IDA	200.00	P084871
2006	P086865	RY-Power Sector	MNA	Yemen, Rep.	IDA	44.00	P086865
2006	P086865	RY-Power Sector	MNA	Yemen, Rep.	IDA	6.00	P086865
2007	P090928	AF PSD Support Project	SAR	Afghanistan	IDA	7.50	P090928
2007	P095229	AO-MS ERL 2	AFR	Angola	IDA	25.50	P095229
2007	P105329	KH-GMS Power Trade Project	EAP	Cambodia	IDA	18.50	P105329
2007	P094306	JO-Amman East Power Plant	MNA	Jordan	Guarantees	45.00	P094306
2007	P098949	VIP 2	ECA	Kyrgyz Republic	IDA	1.20	P098949
2007	P105331	LA-GMS Power Trade Project	EAP	Lao PDR	IDA	12.90	P105331
2007	P104774	LB-Emergency Pwr Reform Capacity Reinfor	MNA	Lebanon	SF	2.50	P104774
2007	P095240	MG—Pwr/Wtr Sect. Recovery and Restruct.	AFR	Madagascar	IDA	6.30	P095240

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2007	P096801	Elect Distrib Rehab	ECA	Turkey	IBRD	269.40	P096801
2007	P069208	UG-Power Sector Dev. Project (FY2007)	AFR	Uganda	IDA	288.00	P069208
2007	P074594	GZ-Emergency Municipal Service Rehab II	MNA	West Bank and Gaza	SF	2.30	P074594
2008	P106654	ARTF Kabul-Aybak MazareSharif Power Proj	SAR	Afghanistan	RE	52.44	P106654
2008	P084404	3A- MZ-MW Transmission Interconnection	AFR	AFR Region	IDA	93.00	P084404
2008	P109885	Rural Investment (AZRIP) Additional Financing	ECA	Azerbaijan	IDA	1.40	P109885
2008	P108843	Bangladesh DSC IV-Supplemental Financing	SAR	Bangladesh	IDA	19.50	P108843
2008	P110110	BD DSC IV-Supplemental Financing II	SAR	Bangladesh	IDA	25.00	P110110
2008	P111019	Additional Financing For The Benin Energy Services Delivery Project	AFR	Benin	IDA	7.00	P111019
2008	P078091	BF-Energy Access SIL	AFR	Burkina Faso	IDA	17.46	P078091
2008	P097974	BI-Multisectoral Water & Electricity Inf	AFR	Burundi	IDA	16.80	P097974
2008	P108905	ZR-EMRRP Supp 2 ERL (FY2008)	AFR	Congo, Dem. Rep.	IDA	7.90	P108905
2008	P109932	DO Emergency Recovery & Disaster Mgmt	LCR	Dominican Republic	IBRD	20.80	P109932
2008	P110202	ER-Add-Fin Power distr & rural electric	AFR	Eritrea	IDA	15.80	P110202
2008	P074011	ET/Nile Basin Initiative:ET-SU Interconn	AFR	Ethiopia	IDA	41.05	P074011
2008	P101556	ET-Elect. Access Rural II SIL (FY2007)	AFR	Ethiopia	IDA	122.20	P101556
2008	P074191	GH-Energy Dev & Access SIL (FY2008)	AFR	Ghana	IDA	77.40	P074191

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2008	P101653	Power System Development Project IV	SAR	India	IBRD	600.00	P101653
2008	P106899	ECSEE APL #3—Montenegro	ECA	Montenegro	IDA	8.20	P106899
2008	P104265	MA–One Support Project	MNA	Morocco	IBRD	123.00	P104265
2008	P095982	Electricity Distribution and Transmission	SAR	Pakistan	IDA	76.45	P095982
2008	P095982	Electricity Distribution and Transmission	SAR	Pakistan	IBRD	159.71	P095982
2008	P106262	PH- Bicol Power Restoration Project	EAP	Philippines	IBRD	12.94	P106262
2008	P101645	TZ-Energy Development & Access Expansion	AFR	Tanzania	IDA	90.30	P101645
2008	P096207	Power Transmission Project	ECA	Ukraine	IBRD	200.00	P096207
2008	P099211	VN-Rural Distribution Project	EAP	Vietnam	IDA	150.00	P099211
2008	P084461	GZ–Electric Utility Management	MNA	West Bank and Gaza	SF	7.40	P084461
2008	P077452	ZM–Incr. Eff. & Access to Elec SIL (FY2008)	AFR	Zambia	IDA	5.12	P077452
2009	P111943	ATRF–Power System Development	SAR	Afghanistan	RE	35.00	P111943
2009	P105654	3A–S. Afr Power Market—Add.Fin. APL1	AFR	AFR Region	IDA	180.62	P105654
2009	P112242	Power Distribution Privatization PRG	ECA	Albania	Guarantees	78.00	P112242
2009	P095965	Siddhirganj Peaking Power Project	SAR	Bangladesh	IDA	43.30	P095965
2009	P110614	BR–Sergipe State Int. Project: Rural Pov	LCR	Brazil	IBRD	3.12	P110614
2009	P105651	GPOBA W3–Ethiopia Rural Elect Expn, Ph2	AFR	Ethiopia	RE	7.00	P105651
2009	P114167	Supplemental Credit for PRSO IV	ECA	Georgia	IDA	8.00	P114167
2009	P112798	Power Sys Dev IV Addl Financing	SAR	India	IBRD	400.00	P112798

FY	Project ID	Project Name	Region	Country	Product line	$ millions	URL
2009	P110173	KE–ESRP Additional Financing SIL	AFR	Kenya	IDA	71.40	P110173
2009	P096648	NG–Commercial Agriculture Development	AFR	Nigeria	IDA	27.00	P096648
2009	P113159	PH–Additional Financing for RPP	EAP	Philippines	IBRD	20.00	P113159
2009	P112334	UG–Energy for Rural Transformation APL2	AFR	Uganda	IDA	26.60	P112334
2009	P113495	Rural Energy II–Additional Financing	EAP	Vietnam	IDA	200.00	P113495
2009	P116854	GZ–Electric Utility Management Add. Fin.	MNA	West Bank and Gaza	SF	2.50	P116854
2009	P092211	RY–Rural Energy Access	MNA	Yemen, Rep.	IDA	16.02	P092211

Source: World Bank.

Note: IBRD = International Bank for Reconstruction and Development; IDA = International Development Agency.

Glossary

Additionality. A criterion often applied to GHG projects, stipulating that project-based GHG reductions should only be quantified if the project activity would not have happened anyway—that is, that the project activity (or the same technologies or practices it employs) would not have been implemented in its baseline scenario and/or that project activity emissions are lower than baseline emissions.

Baseline emissions. An estimate of GHG emissions, removals, or storage associated with a baseline scenario.

Baseline scenario. A hypothetical description of what would most likely have occurred in the absence of any considerations about climate change mitigation.

Build margin. The grid electricity emission factor that reflects how a new power generation or saving project activity affects the construction of new power plants.

Carbon dioxide equivalent. The universal unit of measurement used to indicate the global warming potential of GHGs. It is used to evaluate the impacts of releasing (or avoiding the release of) different GHGs.

Clean Development Mechanism (CDM). A mechanism established by Article 12 of the Kyoto Protocol for project-based emissions reduction activities in developing countries. The CDM is designed to meet two main objectives: to address the sustainability needs of the host country and to increase the opportunities available to Annex I parties to meet their GHG reduction commitments. The CDM allows for the creation, acquisition, and transfer of certified emissions reductions from climate change mitigation projects undertaken in non-Annex I countries.

Combined margin. The weighted average of the operating and build margins.

Emission factor. A factor relating GHG emissions to a level of activity or a certain quantity of inputs or products or services (for example, tonnes of fuel consumed, or units of a product). For example, an electricity emission factor is commonly expressed as tCO_2eq/MWh.

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

GHG accounting. The process of quantifying the impacts on GHG emissions from an activity or organization/institution.

GHG emissions. GHGs released into the atmosphere.

GHG Protocol. A multistakeholder partnership of businesses, nongovernmental organizations, governments, academics, and others convened by the World Business Council for Sustainable Development and the World Resources Institute to design and develop internationally accepted GHG accounting and reporting standards and/or protocols, and to promote their broad adoption.

GHG source. Any physical unit or process that releases GHGs into the atmosphere.

Global warming potential. A factor describing the radiative forcing impact (degree of harm to the atmosphere) of one unit of a given GHG relative to one unit of CO_2.

Greenhouse gases. Gases that absorb and emit radiation at specific wavelengths within the spectrum of infrared radiation emitted by the Earth's surface, the atmosphere, and clouds. The six main GHGs whose emissions are human-caused are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Intergovernmental Panel on Climate Change (IPCC). International body of climate change scientists. The role of the IPCC is to assess the scientific, technical, and socioeconomic information relevant to the understanding of the risk of human-induced climate change (www.ipcc.ch).

Inventory. A quantified list of a project's, organization's, or country's GHG emissions and sources.

Life-cycle analysis. Assessment using a "cradle-to-grave" approach of the sum of a product's effects (for example, GHG emissions) at each step in its life cycle, including resource extraction, production of material, use, and waste disposal.

Net GHG accounting. Quantification of the difference between all GHG emissions from GHG sources within the project boundary after the implementation of the project and the GHG emissions that would have occurred in a "without project" baseline scenario.

Operating margin. The grid electricity emission factor that reflects how a new power-generation or -saving project activity affects the operation of existing power plants.

Project boundary. The physical location of the activities that are evaluated for their GHG impacts and the list of GHG sources that are included in a GHG accounting exercise. Under the CDM, the project boundary is "all anthropogenic emissions by sources of GHGs under the control of the project participants that are significant and reasonably attributable to the CDM project activity."

Project emissions. An estimate of GHG emissions, removals, or storage associated with a project scenario.

Project scenario. A description of the technology and operational characteristics of the project activity implemented.

Value chain. All the upstream and downstream activities associated with the production of goods or services.

Sources: Adapted from GHG 2005a and UNFCCC 2009c.

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