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PRACTICAL BASELINE RECOMMENDATIONS FOR GREENHOUSE GAS MITIGATION PROJECTS IN THE ELECTRIC POWER SECTOR

INFORMATION PAPER

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FOREWORD

This document was prepared in May 2002 by the IEA Secretariat at the request of the Annex I Expert Group on the United Nations Framework Convention on Climate Change. The Annex I Expert Group oversees development of analytical papers for the purpose of providing useful and timely input to the climate change negotiations. These papers may also be useful to national policy makers and other decision-makers. In a collaborative effort, authors work with the Annex I Expert Group to develop these papers. However, the papers do not necessarily represent the views of the OECD or the IEA, nor are they intended to prejudge the views of countries participating in the Annex I Expert Group. Rather, they are Secretariat information papers intended to inform Member countries, as well as the UNFCCC audience.

The Annex I Parties or countries referred to in this document refer to those listed in Annex I to the UNFCCC (as amended at the 3rd Conference of the Parties in December 1997): Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, the European Community, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russian Federation, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, Ukraine, United Kingdom of Great Britain and Northern Ireland, and United States of America. Where this document refers to "countries" or "governments" it is also intended to include "regional economic organisations", if appropriate.

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Executive Summary

Emission baselines are necessary to determine the emission reductions resulting from a GHG mitigation project and calculating the associated emission credits. They seek to quantify the amount of greenhouse gas (GHG) emissions in the hypothetical "what would happen otherwise" case against which actual, monitored project emissions are compared. Emission baselines are thus required for the implementation of the Kyoto Protocol's project-based mechanisms, i.e. the Clean Development Mechanism (CDM) and Joint Implementation (JI). They are also required for any project-based trading programme to reduce GHG emissions. While the emphasis of this paper is on CDM mitigation projects in the electric power sector, the analysis and baseline recommendations may apply equally for electricity projects implemented in other contexts.

As the Executive Board (EB) of the CDM (or any entity involved in project development) takes on the task of developing and recommending "general guidance on methodologies relating to baselines,"[1] it will need to balance several considerations and criteria, including ensuring that baselines are suitably accurate and have manageable transaction costs. While most of the GHG-mitigation projects under the Activities Implemented Jointly (AIJ) pilot phase under the UNFCCC and other early credit trading projects have conducted project-specific baseline studies, the baselines used have not been particularly transparent or consistent and can present significant transaction costs. As a means to address these and other issues, the notion of baseline standardisation has gained considerable attention and support. Baseline standardisation, if done well and tailored to appropriate project types, can simultaneously promote consistency, limit the opportunities for gaming (selecting advantageous baselines), and reduce transaction costs.

This paper identifies workable methodologies, specifically with respect to standardising baselines for emission-reducing electricity projects. It is hoped that this work can contribute to the successful implementation of the CDM, which largely rests under the responsibility of the CDM Executive Board.

This report constructs a decision framework that can be applied to all electricity projects. No single methodology can suit all the potential diversity of CDM projects in the electricity sector, which span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. This diversity calls for a range of baseline approaches.

This paper proposes a three-category framework for the different projects (see Table ES-1), with baseline and additionality methods specific to each, in order to balance the objectives of low transaction costs and environmental accuracy. Two key factors are used to define these broad categories: *environmental risk*, the potential for significant crediting in excess of actual emission reductions, and *project scale*, an indicator of a project's ability to absorb the added costs of more thorough baseline analysis. Because the cost of a more project-specific baseline study could easily overwhelm the value of the CER revenues of a small project, simplified baseline methodologies are essential if smaller CDM projects are to be feasible. In contrast, since the cost of a project-specific baseline study will likely be a small fraction of the value of the revenues of a large project, then a more detailed baseline study would appear warranted and feasible to the extent that it adds rigor and reduces environmental risk. Moreover, the environmental risk for certain projects (such as fast-track renewable activities) is likely to be acceptably small, so the more rigorous baseline and additionality methodologies can be reserved for projects that present greater environmental risk, i.e. those projects employing more conventional technologies, especially at large scales.

[1] Decision 17/CP.7 Appendix C (a), http://unfccc.int/cdm/rules/modproced.html#MP41

The crux of the baseline challenge for electricity projects clearly resides in determining the "avoided generation", or what would have happened without the CDM or other GHG-mitigation project. The fundamental question is whether the *avoided generation* is on the "build margin" (i.e. replacing a facility that would have otherwise been built) and/or "operating margin" (i.e. affecting the *operation* of current and/or future power plants). Different methods are examined, with the *combined* margin approach, which is a combination of *build* margin and *operating* margin approaches, being recommended for most types of projects:

- ***Combined Margin*****:** Since most electricity projects are likely to affect both the operating margin (in the short run) and the build margin (in the long run), electricity baselines should reflect a combination of these effects. Standardised CDM baseline methods need to be transparent and widely applicable across non-Annex I countries given available data and resources, and recognise relevant COP decisions on crediting lifetimes, conservatism, and other criteria. Based on these considerations, a combined margin approach (i.e. an average of the operating margin and build margin) is recommended as the standardised baseline methodology for most electricity projects. Given the COP decision on CDM crediting lifetimes, an effective combined margin method consists of:

    - the average emissions rate of the operating margin baseline (system average minus low-cost/must-run resources) and the build margin baseline (based on the cohort of 20% most recently built or under construction, $BM_{historical}$) for the first 7 years of project crediting (or 10 years for projects electing 10 year credit lifetime), per the following equation:

$$Combined\_Margin_{1stCreditingPeriod} = \frac{OM_{year1} + BM_{historical}}{2}$$

    - the build margin baseline calculated based on new construction during the years 1-7 ($BM_{years\ 1\text{-}7}$) for any subsequent crediting periods:

$$Combined\_Margin_{2nd\&3rdCreditingPeriods} = BM_{years1-7}$$

  As demonstrated by the Dutch CERUPT methodology in use for small-scale projects, the data for an approach like this are readily available and the calculations are straightforward (CERUPT, 2001).

- ***Build Margin (BM)*****:** Even if a CDM project may not displace new plant additions, it is likely to delay them. Since this delay will typically affect all prospective new capacity[2], the build margin baseline should generally reflect all power plant types being added to a system. It is recommended that this be calculated using the generation-weighted average emissions rate of the most recent 20% of plants built (on a generation basis), or the most recent 5 plants, whichever is greater.

- ***Operating Margin (OM)*****:** Operating margin effects may predominate in the early years after CDM project implementation, before build margin effects take hold. Several operating margin methods have been suggested and applied. The most accurate operating margin methods use dispatch data or models. While useful in situations of high data and resource availability, these methods are unlikely

[2] Different project types may tend to have different lead-time and ownership characteristics that might affect how prone they are to delay or cancellation. For example, some countries may be looking at both independently-owned NGCCs with 1-2 year lead-time and longer lead-time state-owned hydro projects. However, these considerations vary among countries, are difficult to generalize, and should, in the longer run, have a limited impact.

to be widely applicable. The simplest method, a weighted-average of all resources, suffers from the potential for large inaccuracies. Therefore, we suggest a practical method – the weighted average of all resources *except* zero fuel-cost/must-run facilities -- that should in most cases approximate the operating margin calculated using more sophisticated techniques.[3]

There are some particular types of electricity projects for which a baseline based on a straight combined margin approach may not be the most appropriate option.

For brownfield (retrofit and fuel switch) projects, it is recommended that the emission rate of the existing facility may be a valid baseline up to the amount of generation that the existing facility produces. For power generation beyond this amount, the combined margin baseline methodology should apply.

Off-grid projects also deserve particular treatment. It is critical that off-grid projects, such as solar home systems, hydro mini-grids, and biomass gasifiers, be provided with simplified, standardised baselines, given the small amount of CERs and potentially large development benefits they are likely to produce. Therefore we recommend that the standardised baseline algorithms for small off-grid projects recommended under the Dutch CERUPT programme be adopted. Detailed emission factors are provided for each type of off-grid project (in Annex B).

A combined-margin approach may not be sufficient for calculating emission baselines in cases where project proponents can clearly demonstrate that only one specific plant or plant type is being displaced by a category III project, e.g. higher-efficiency fossil plants[4] proposed to replace a lower-efficiency one at the same site. In such situations, *minimum performance parameters* (e.g., for efficiency and load factors) should be established to ensure that the baseline is not based on outdated or inefficient technology assumptions.

The recommended baseline approaches and suggested additionality tests[5] for each of the three project categories (table ES-1) are summarised as follows:

[3] Exceptions may need to be made for countries and regions with predominantly hydro resources.

[4] The burden of evidence for such projects may need to be significant where a developer wishes to use a fuel-specific baseline that is considerably higher than the standardized combined margin baseline would suggest. For instance, the developer of high-efficiency coal plant would need to demonstrate why oil, gas, or other plants are not competitive for meeting the same consumer loads.

[5] Although the focus of this study is on baselines, suggestions are also made for the treatment of additionality.

- **Category I:** offers the greatest degree of standardisation and lowest transaction costs and is applied to smaller-scale projects that present the least environmental risk. The baselines for grid-connected small project are calculated based on a combined margin approach; while the baselines for the different small-scale off-grid projects, as noted above, are based on standardised emission factors. Category I projects are considered to be additional by default and their performance would automatically be compared with a standardised baseline. Since the absence of an additionality evaluation presents some risk of generating credit to business-as-usual activities, the project types placed in Category I (vs. II or III) should be reviewed periodically. It is recommended that initially fast track renewable and off-grid projects be considered for Category I.[6] This approach is similar to the Dutch CERUPT electricity baseline methodology for small-scale renewable energy and efficiency projects.

- **Category II** projects are those that present somewhat greater environmental risk due their larger size *or* use of conventional fuels and technologies (compared to Category I). Suggested Category II projects include fast-track energy efficiency and fossil generation projects, and would be subject to a simple "additionality test", such as emitting at a lower level than a specified emissions rate. The recommended baseline is the same for Category I projects.

- **Category III** projects would need a more thorough, project-specific baseline scenario analysis as they are larger projects, and/or pose greater environmental risk. In addition, this category could be optional for any project that chooses to opt out of Category I or II approaches. Scenario analysis involves considering a set of plausible, alternative scenarios for what would happen in the absence of a CDM project, and then using a well-defined and reproducible process to determine the most likely baseline. Where the most likely scenario is determined to be the ongoing expansion and operation of the overall electricity grid, rather than any specific investment, it is recommended that the project adopt the same baseline approach as Category I and II projects. (This outcome could also arise if several new generation options are all plausible, and there is no compelling justification to deem one option among the "most likely".) If the most likely scenario is determined to be a specific investment, facility, or activity, the baseline emissions rate can be quantified directly based on the presumed characteristics of the baseline investment or facility.

[6] For instance, eventually (or in some particular cases) mature and frequently cost-effective renewable energy technologies, such as small-scale hydroelectricity plants could be potentially be moved to Category II. This would help address the concern expressed by some of this report's reviewers' concern with the recommendation that some fast-track projects, albeit quite small with low environmental risks, would not need to pass an additionality test.

Table ES-1. Classification of Electricity Project Types by Baseline Method Category*

Category	Eligible Project Types	Additionality Approach	Baseline Approach
Category I	• Fast-track new renewable projects (FT1a) • Fast-track off-grid projects (FT1b)	Additionality is automatically assumed.	Baseline emissions rate is predetermined, based on combined margin approach for grid-connected projects. Baseline emission factors are recommended for different types of off-grid projects.
Category II	• Fast-track energy efficiency projects (FT2) • Other fast-track projects (FT3) • Other projects, if deemed appropriate, e.g. possibly mid-size renewable technologies	Additionality is dependent on passing a simple additionality screen.	Baseline emissions rate is predetermined, based on combined margin approach for grid-connected projects.
Category III	• All other projects, including large, new (NFT1), brownfield (NFT4), efficiency (NFT2), and cogeneration (NFT3) projects • Projects qualifying for I or II, but claiming that the standardised baseline above is inapplicable	Additionality is dependent on outcome of scenario analysis.	Baseline emissions rate is either based on baseline scenario (if a specific alternative investment is identified) or is the predetermined level calculated from the combined margin approach.

* terms used in this table are explained below

* FT (fast-track) refers to projects that would be eligible under the simplified procedures and modalities for small-scale CDM project activities. NFT (non-fast track) are not eligible.

The methodology elaborated here is simple, robust, and comprehensive, and encompasses the diversity of projects that may arise in the electric sector. It identifies standardised, streamlined approaches to reduce transaction costs where feasible, yet relies on more detailed methods that are more rigorous for those classes of projects for which preserving environmental integrity is more likely to be an issue. The methodology is rendered as a step-by-step decision tree, as shown in Figure ES-1.

The paper also provides recommendations on the “geographic aggregation” of the baselines for projects in the electric power sector. It concludes that the default level for standardised electricity baselines should be the country level, with host countries able to define separate sub-national grids or combine with other countries, based on actual power system management practices and transmission availability.

It is recommended that project boundaries (i.e. which GHG emissions and sources associated with a project should be included in the emission baselines) for power generation projects be based on direct on-site emissions. The recommendations also make a distinction between (i) demand-side efficiency and distributed generation projects, and (ii) other supply-side projects in the electric power sector (e.g. a new grid-connected power plant). Demand-side efficiency and distributed generation projects should be credited for avoided transmission and distribution (T&D) losses, using average grid area losses (and excluding “non-technical losses”), or national average losses where grid-specific loss data are unavailable. T&D would not be taken into account for the other types of electricity projects, as they are likely to not have any impact on T&D losses. Other boundary issues, such as upstream natural gas leakage, might merit further examination, but are not included in the electricity baseline recommendations at this time.

Next steps: To ensure that the recommended methodology is indeed workable in most, if not all, electricity contexts, several next steps should be taken, including:

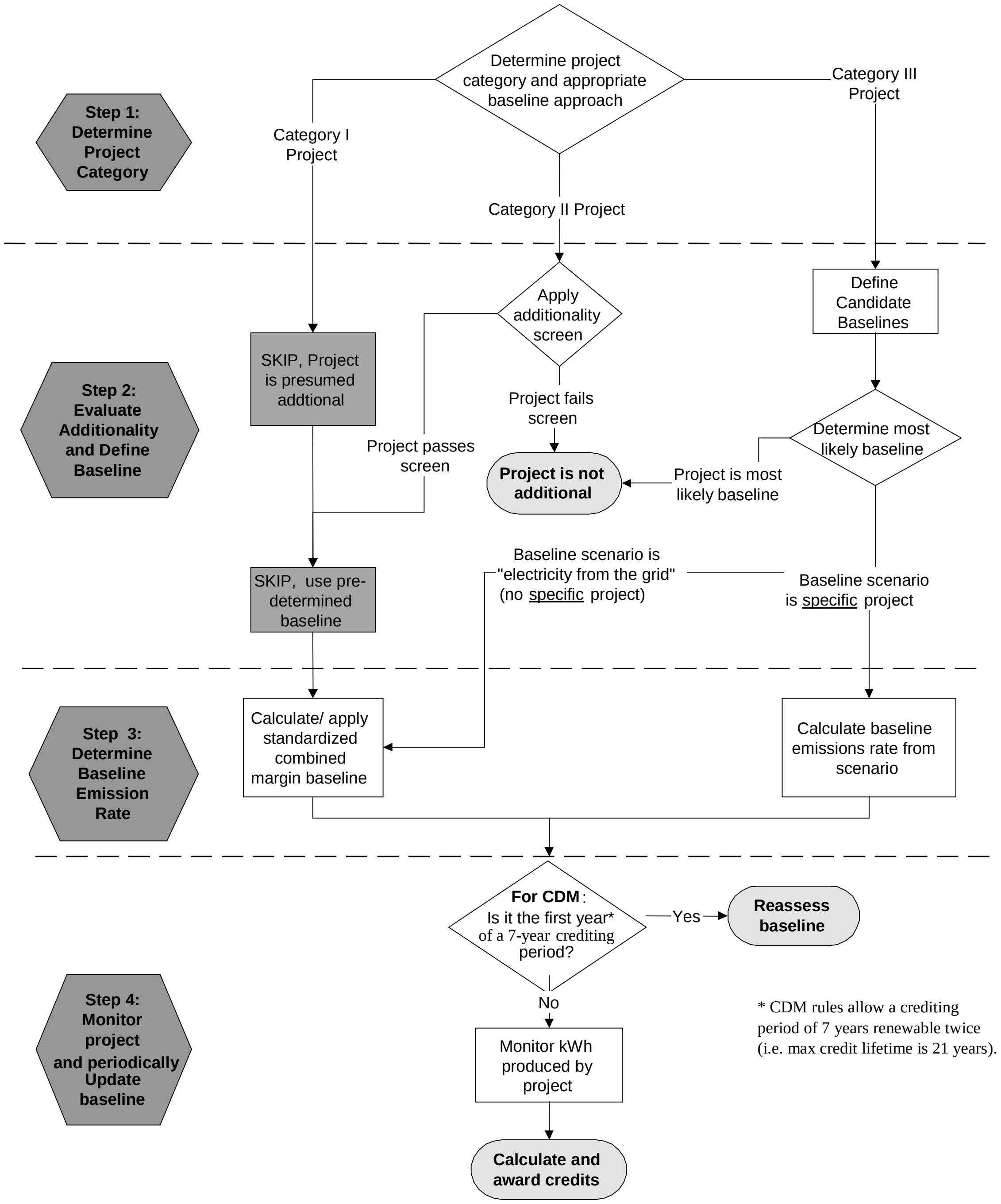
- further research and development of workable additionality testing procedures,
- review and input by host countries and other interested parties, and
- testing the recommended methodology in a number of countries using real or case study examples.

These steps will be essential in validating, as well as identifying any important elaboration and modifications to the recommended methodology that might be needed to improve the accuracy of the baseline and to better reflect various country-specific electricity contexts. Among the issues that will be important to consider are, for example:

a) Possibilities of additional break-down of project categories (and methodologies) to account for different contexts (e.g. situations of fully-met electricity demand vs. situations of under-capacity);
b) Application of the methodology on an *ex post* basis based on actual data for the period of project performance;
c) More detailed distinction of project types by category, in particular which require further additionality testing (Category II) or project-specific analysis (Category III);
d) Possibilities to refine the approach for hydro-rich countries;
e) Enhanced accounting for upstream emissions, particularly T&D losses and methane emissions from natural gas systems.

Once these revisions are incorporated, the methodology can then be translated into short and simple to use step-by-step guidelines, with possibly numerical examples, for host countries and project developers.

Figure ES-1. Overview of recommended baseline methodology



1. Background and Context

1.1 Introduction

The threat of global climate disruption resulting from greenhouse gas emissions is rapidly emerging as one of the great sustainable development challenges for policy makers in the 21st century. The Kyoto Protocol to the UN Framework Convention on Climate Change (UNFCCC), which appears to be moving toward ratification, represents a major step toward meeting this challenge. Countries, individually or jointly, are also developing domestic climate change programmes, which may apply prior to entry into force of the Protocol, or outside of the Protocol itself.

The Kyoto Protocol creates two distinct types of emissions trading to assist its Annex I Parties (the industrialised and transition economies) in achieving their binding emissions targets. The first, international emissions trading, is an *allowance* or “cap-and-trade” system, whereby emissions rights or assigned amount units (AAU) can be exchanged among Annex I countries. The second type is *credit* trading, embodied in the Clean Development Mechanism (CDM) and Joint Implementation (JI), which enables Annex I countries to purchase the emission reductions generated by specific project activities in developing (non-Annex I), transition and industrialised (Annex I) countries, respectively. Allowance and credit trading markets can also be developed at a national or regional level. The creation of these emissions trading markets offers Parties and entities the potential to increase the economic efficiency of meeting their emissions targets and simultaneously, to spur technology transfer and sustainable development in the developing world.

The success of all credit trading regimes depends on clear rules: technical, methodological, and administrative processes that ensure credits are awarded to projects in a fair, consistent and transparent manner. One of the principal challenges in awarding credits for GHG mitigation projects is the determination of emission baselines. Emission baselines are the best estimate or convention for what would have occurred in the absence of a project. Emissions credits, (under the Kyoto Protocol called Certified Emission Reductions (CERs) in the case of CDM or Emission Reduction Units (ERUs) in the case of JI), are then calculated as the difference between emissions of the project and its baseline.

Determining the emissions a project avoids poses two related and often difficult to answer counterfactual questions: 1) Is the project *additional* to normal business (or government) practice? In other words, is it being implemented because of the additional incentive provided by the credit-trading program? (“the additionality question”); 2) Assuming the project is additional, what is the quantity of net emissions reductions (or sequestration) it causes relative to what would have occurred in the absence of the proposed project? (“the baseline question”). In some senses, the two questions are inseparable; both involve an examination of the counterfactual situation. While presenting ways to address the first question (i.e. additionality), this study focuses on the question of baselines.

Since baseline methods determine how many emission credits a project will accrue, much is at stake. Systematic error in baseline estimation could result in a variety of undesirable outcomes. Overly lax (high) baselines will simply increase global emissions, since excess credits will enable increased emissions without truly compensating emissions reductions.[7] In so doing, lax baselines might undermine the credibility of credit trading, which is essential for its success. On the other hand, baselines set too

[7] Note this concern exists largely for the CDM. In the context of JI, where host countries have a fixed emission target, overly high baselines will simply reduce the amount of AAUs available for other purposes such as covering domestic emissions and engaging in emissions trading.

stringently (low) will reduce crediting and the economic incentive for GHG mitigation projects, and could result in lost opportunities to invest in GHG reductions in developing countries, and presumably higher costs for compliance with emissions targets.

As the Executive Board (EB) of the CDM (or any other body concerned with the development of project rules) takes on the task of developing and recommending "general guidance on methodologies relating to baselines,"[8] it must balance these concerns, while ensuring the reliability, consistency, and transparency at manageable transaction costs. Clearly, guidance on emission baselines produced by the CDM EB for CDM projects is also likely to be useful when developing baselines for JI, or other GHG mitigation, projects. (This paper refers to the CDM EB to simplify the text). Environmentally beneficial projects might not be initiated if developers perceive the transaction costs and uncertainty involved with baseline determination as a major barrier. While most of the projects under the Activities Implemented Jointly (AIJ) pilot phase and other early credit trading projects have conducted project-specific baseline studies, they have not been particularly transparent or consistent (UNEP/OECD/IEA 2001; Parkinson et al, 1999) and can be costly. As a means to address these and other issues, the notion of baseline standardisation has gained considerable attention and support. Baseline standardisation (i.e. standardised emission rates, parameters and/or methodologies), if done well and tailored to appropriate project types, can simultaneously promote consistency, limit the opportunities for gaming (selecting advantageous baselines), and reduce transaction costs.

With this in mind, the Conference of the Parties (COP) to the UNFCCC also tasked the EB to provide specific guidance on:

- "the appropriate level of standardisation of methodologies to allow a reasonable estimation of what would have occurred in the absence of a project activity wherever possible and appropriate...,
- decision trees and other methodological tools, where appropriate, to guide choices in order to ensure that the most appropriate methodologies are selected, taking into account relevant circumstances, and in
- the breadth of the baseline, e.g. how the baseline makes comparisons between technology/fuel used and other technologies/fuels in the sector" (Appendix C of Decision 17/CP.7).

This paper provides insights on these issues, specifically with respect to standardisation of baselines for GHG mitigation projects in the electric power sector. Electricity baselines are a natural starting point for baseline standardisation because of:

- The sizeable market opportunities in this sector. Based on International Energy Agency data (IEA, 2000), roughly 560 GW of new power plants will come on-line in non-Annex B countries between 1997 and 2010, producing roughly 2000 MtC (or 7200 MtCO2) during that time. In fact, coal is expected to continue to be the world's largest source of power generation through to 2020, and the most important new generation source in many developing countries. The CDM could shift that mix of plants towards lower carbon technologies.
- The diversity of project types that would require an electricity baseline to assess their emission reductions. A variety of projects -- from new large-scale power plants to energy efficiency improvements and landfill gas capture – will result in the increase or decrease of electricity generation or shifting among generation sources.
- The need for simplified procedures for small-scale electricity projects to be developed soon, pursuant to the fast track provisions of the COP7 (or "Marrakech Accords") (Decision 17/CP.7,6c)

[8] Decision 17/CP.7 Appendix C (a), http://unfccc.int/cdm/rules/modproced.html#MP41

- The substantial base of research on and practical experience with standardisation of electricity baselines.

This paper begins by reviewing some of the key insights from past work on electricity baselines. Section 2 describes the overall study objectives and approach, and lays out some key criteria and project typologies before using them to evaluate specific electricity baseline options. Section 3 presents some practical recommendations for standardising baselines methodologies across all electricity project types, using a decision tree approach. And finally Section 4 provides some conclusions with respect to moving forward. It is important to note that while the emphasis here is on baselines for CDM projects, many of the recommendations may apply equally well in the context of Joint Implementation (as electricity systems in Central and Eastern Europe face many of the same planning and operational considerations as those in the rest of the world), as well as to domestic credit schemes.

1.2 Electricity baselines: literature and experience

Over the past five years, research, case studies, and pilot projects have generated substantial literature and lessons learned related to electricity baseline methodologies. This experience is summarised in Table 1-1. Across the many project and case study contexts shown, many projects have established baselines using project-specific, scenario analysis methods. Scenario analysis involves creating a set of plausible propositions as to what would happen in the absence of a CDM investment (including the project itself), and then to identifying the most likely baseline scenario from among them. This baseline identification process can either be done on an ad hoc basis (e.g. as often the case for AIJ projects) or using more well-defined and reproducible methods, such as regulatory and policy assessment, investment analysis, market barrier analysis, risk analysis, and conservatism principles (ERUPT, CERUPT, UNIDO, and PCF).[9] Once the most likely baseline scenario is identified – e.g. a lower-efficiency power plant that will no longer be built as a result of the project – then it can be translated into a baseline emission rate, expressed in gCO_2eq/kWh.

However, such ad-hoc project-specific methods as noted above have tended to result in inconsistent and non-transparent baselines, and can introduce costs, and uncertainties, that some projects would not be able to bear. Thus the greater focus in this paper is on identifying opportunities and approaches to develop recommendations for standardised baseline emission rates or methodologies (actual values or algorithms to determine them, often referred to "multi-project" baselines), based on pre-determined notions of what the baseline scenario is for all relevant electricity projects. Standardised baseline approaches have already been adopted by the Dutch CERUPT and the Oregon Climate Trust to award emission credits to electricity projects, by various voluntary programs (such as the US 1605b program), and are under active consideration in Mexico (ATPAE/USAID, 2002). In each case, a specific methodology is used to calculate a corresponding electricity baseline emission rate (in gCO_2eq/kWh), which is then available to all projects that are judged eligible and approved. In the case of the CERUPT procedures, for instance, only small-scale (fast track) projects are eligible for this pre-determined baseline.

[9] Sources include ERUPT (2001), CERUPT (2001), PCF (2000 and 2001), UNIDO, (2001), USDOE (2001), and many others.

Table 1-1. Emission credit trading programmes and efforts to standardise electricity baselines

Sponsoring Institution or Emissions Trading Initiative	**Relevant Documents**	Executed credit trades/sales	**Standardisations discussed/proposed (D) or implemented (I)**
Activities Implemented Jointly under UNFCCC	Project documents available at UNFCCC website	Not under UNFCCC	None (Projects used ad hoc project-specific methods)
Prototype Carbon Fund (PCF)	Several baseline studies for electricity projects. Methodology papers	Yes	None (Learn-by-doing approach and use of several scenario-based, project-specific methods)
ERUPT	Step-wise guideline documents, including specific to the electricity sector	Yes	Parameters for project-specific scenario analysis T&D loss factors (I)
CERUPT	Similar to ERUPT	Yes	Parameters for project-specific scenario analysis Electricity baseline emissions rate for small-scale projects (I) T&D loss factors (I)
OECD/IEA (for the Annex I Expert Group on the UNFCCC)	Research papers and books	No	Several standardised electricity baseline methodologies (D)
UNEP/OECD/IEA	International Baseline Workshop and Proceedings	No	Recommendations on elements of standardised electricity baselines (D)
Japanese Government Working Group	“Simplified Methodology” proposed	No	Decision trees for guiding project-specific baseline scenario analysis
PROBASE/EU	Research Papers	No	Standardised electricity baseline methodologies (D)
US government and national laboratories (EPA, DOE, LBNL)	Research papers Case studies in non-Annex I countries	No	Several standardised electricity baseline methodologies (D)
UNIDO	Research papers on industrial projects Case studies in non-Annex I countries	No	Decision trees for additionality testing/baseline scenario selection (D)
Oregon Climate Trust	Guidelines available	Yes	Electricity baseline emissions rate (I)
US Voluntary Reporting (1605b)	Guidelines available	No	Electricity baseline emissions rate (I)
Canadian Greenhouse Gas Emission Reduction Trading Pilot	Research papers Alberta Emissions Quantification Working Group Report	Yes	Recommended electricity baseline method ()
Mexico (ATPAE/CONAE)	Research papers, recommended baseline methods, decision process	No	Electricity baseline emissions rate (D/I)

Several institutions, including OECD/IEA, USEPA, USDOE, UNEP, and others have sponsored research and case studies to evaluate alternative methods for developing electricity baselines that are sufficiently accurate, applicable across many different contexts, and feasible given data and institutional constraints (OECD/IEA, 2000; Ellis and Bosi, 1999; Sathaye et al, 2001; USDOE/SAIC, 2001; Lazarus et al, 1999 and 2000). These reports have raised a number of questions that need to be addressed to standardise baselines: basis (underlying suppositions about sources of avoided generation), geographical aggregation, dynamics, and stringency. These issues and options are discussed in further detail in Section 2.

In May 2001, UNEP, OECD, and IEA jointly held an international workshop to examine options for standardising baselines. The electricity sector working group was by far the most heavily attended, a sign of intense interest and relevance of this sector. The working group came to the following conclusions, which are reflected in the Chairman's report (UNEP/OECD/IEA, 2001):

- Different project types may need different baselines.
- In particular, grid and off-grid projects should be distinguished from one another.
- Greenfield and retrofit projects should also be distinguished, with the retrofit project potentially able to use previous plant emission levels (pre-retrofit) as a baseline for generation up to pre-project output levels.
- Default baseline values are recommended for small off-grid renewable projects.
- For grid-connected projects, baselines should take into account a specific regional, national, or sub-national grid's characteristics, as defined by transmission, power pooling, or other operational considerations.
- Electricity baselines should be expressed in gCO_2 equivalent per kWh.
- All direct on-site GHG emissions from electricity generation should be included.
- Baseline calculation methods should account for the fact that some power sector data may be difficult to obtain, especially for proprietary or cost reasons.

The workshop debate reflected "a clear need for more work and discussion in order to reach concrete baseline recommendations for different types of possible JI and CDM projects." This study seeks to build on this workshop's conclusions, as well as project experience and analytical baselines work.

1.3 Approach

It is timely to distil experience with developing emission baselines for electricity projects and develop specific baseline recommendations. The intent of this paper is to contribute to progress towards common, widely accepted practice. By doing so, this effort can help to reduce uncertainties for all parties and stakeholders, to enhance environmental integrity (e.g. through greater transparency and consistency), and thus to enhance the flow of sound projects. It can also contribute to facilitating the task of operational entities charged with the validation and verification of projects.

For the purposes of this analysis, "electricity projects" encompass activities that affect either power supply or demand, including new generating units, retrofits or changed practices at existing facilities, off-grid electricity provision, energy efficiency, and cogeneration installations. However, given that calculating emission reductions for the latter two activities involves a greater number of steps (e.g. baselines for energy efficiency are based on a two-step approach: (i) the calculation of energy use baselines; and (ii) the "translation" of this energy use baseline into GHG emissions, using a baseline for avoided electricity emissions)[10] emission baselines for these two types of projects are only partially addressed here. Thus, the principal focus of this paper is on the <u>supply-side</u> of the electric power sector.

[10] For more information on baseline methodologies for energy efficiency projects, see OECD/IEA (2000).

The approach undertaken involved:

1. Reviewing the body of accumulated research and experience with electricity baselines, as summarised (Section 1.2);
2. Identifying commonly-accepted criteria for baseline methodologies (Section 1.4);
3. Developing a typology of electricity projects with the intent of identifying appropriate baseline approaches for each. (Section 1.5)
4. Laying out a framework for comparing baseline methods (Section 2.1)
5. Defining the emission boundaries under consideration and the geographic coverage of proposed electricity baselines (Section 2.4)
6. Reviewing fundamental baseline approaches and discrete standardisation options, their advantages and disadvantages. (Section 2.2, 2.5-2.10)
7. Recommending specific baseline and additionality approaches, matching methods with project characteristics (Section 3)

The recommendations are outlined in step-by-step procedures, and displayed schematically in a decision tree, to help the reader – and eventually the project proponents – follow the process. The goal of this paper is to provide a stepping-stone to CDM baseline guidelines that might ultimately resemble the straightforward IPCC inventory guidelines, procedures sufficient clear for application by institutions in nearly all countries. To this end, this paper suggests default methodologies, and where possible, discrete algorithms for calculating project baselines. And as with the IPCC Guidelines for National GHG Inventories, the approach recommended here allows project developers to opt for more detailed and thorough baseline methodologies, where desired and justified.

1.4 Criteria for evaluating baseline methodologies

The numerous baseline documents to date (see Section 1.5) have elaborated several key criteria to use in evaluating baseline methods and selecting specific baseline scenarios. Most of these criteria are well summarised in a few lines from the COP7 decision that, "recognising the need for establishing *reliable*, *transparent* and *conservative* baselines…", issues terms of reference for baseline methodologies in order to: "promote *consistency*, *transparency* and *predictability…*; provide *rigour* to ensure that net reductions in anthropogenic emissions are real and measurable, and an *accurate* reflection of what has occurred within the project boundary…; ensure *applicability in different geographical regions* and to those project categories which are eligible in accordance with decision 17/CP.7 and relevant decisions of the COP/MOP…; [and] be *conservative* [in standardisation] in order to prevent any overestimation of reductions in anthropogenic emissions." (App.C/Decision 17/CP.7, (a)(ii-iv) and (b)(v))

These recommendations echo criteria that have been presented in several preceding baseline studies (e.g., Ellis and Bosi, 1999; Puhl, 2001; Lazarus and Kartha, 2001). A comprehensive listing of the key criteria used here to judge baseline methodologies is:

- **Accuracy and rigour**: to ensure reductions are real and measurable and projects are additional;
- **Transparency**: to enhance credibility by making methods and assumptions clearly explained and to make baseline reports accessible for review;
- **Cost-effectiveness**: to ensure the transaction cost of baseline development is justified by its contribution to a more accurate baseline, and acceptable given the scale of the project and the economic value of credits likely to be awarded;
- **Maintenance of adequate incentives:** to ensure that baselines are not unduly stringent, thereby discouraging CDM projects that would in fact be additional and beneficial to host countries in terms of sustainable development.
- **Practicality**: to account for data and institutional constraints and ensure ease of implementation

- **Wide applicability:** to enable use across many national contexts;
- **Consistency**: to level the playing field among similar projects in similar circumstances, and to assist the verification/validation process.
- **Reproducibility**: to yield similar results each time method applied, as a sign of objective, systematic procedure;
- **Conservatism**: to promote environmental integrity, e.g. by selecting the lower end of a range of plausible baseline emissions if there is uncertainty;

Clearly, it will be nearly impossible for an individual methodology to rate highly in all nine criteria, given that some, such as conservatism and maintenance of incentives, might point in opposite directions. Tradeoffs among these criteria will ultimately need to be made.

One key criteria for this study is "practicality", as data availability is essential for developing implementable and *practical* baseline recommendations.

1.5 A typology of potential GHG mitigation projects in the electric power sector

Electricity baseline procedures need to anticipate and address a wide diversity of projects – from remote and off-grid solar installations to new, large-scale power plants to refurbishment of aging infrastructure to innovative efficiency programs. Table 1-2 provides a scheme for classifying the various project types, and match types of electricity projects with recommended baseline methods.

Though each project type presents different plausible baselines, and risks to investors, buyers, and the environment, there are also common elements among most of them. Nearly all but the remote and off-grid projects will displace electricity from the local grid system, and the displaced electricity generation is the element that presents the most important opportunity for standardisation across GHG mitigation projects in the electric power sector.

As mentioned above, it will be more challenging to develop simple, comprehensive emission baseline methods for energy efficiency and cogeneration projects. This analysis considers, for these projects, only the part of the baseline exercise dealing with emissions savings attributable to displaced electricity generation.

Table 1-2. Typology of potential CDM electricity projects

Code	Project type	Examples
Fast track (FT) [11]		
FT1a	New renewable on-grid electricity projects (< 15 MW)	• 10 MW windfarm • 5 MW hydro facility
FT1b	New remote and off-grid renewable electricity projects	• Solar PV home system project • Remote hydro mini-grid
FT2	Energy efficiency projects (< 15 GWh/yr)	• Efficient motor replacement program
FT3	Other small projects (<15 $kTCO_2eq$/yr)	• Gas-fired combined heat-and-power project • Fuel switch from higher carbon to lower carbon fuels (e.g. gas or biomass)
Non-fast track (NFT)[12]		
NFT1a	New/Greenfield (zero or low carbon)	• New 100 MW windfarm • New 500 MW hydro
NFT1b	New/Greenfield (fossil)	• New 500 MW supercritical (high-efficiency) coal plant
NFT2	Energy efficiency	• Major industrial process change (> 15 GWh/yr saved)
NFT3	Cogeneration	• 300 MW combined heat-and-power project
NFT4a	Existing/brownfield – Higher efficiency or increased output, same fuel	• Repowering a single cycle gas-fired turbine to combined cycle operation • Retrofitting and improving performance at poorly performing fossil-fired plant • Adding turbines to an existing hydro dam
NFT4b	Existing/brownfield – Fuel switch	• Converting coal or fuel oil plant to burn gas • Co-firing biomass at a large coal plant

[11] The sizes shown for "fast-track" projects reflect the decision in the Marrakech Accords on simplified modalities and procedures for small-scale CDM projects. Further guidance from the CDM Executive Board is expected on the project types and sizes eligible under each of these categories. "Non-fast track" projects are those currently excluded from this decision.

[12] Non-fast-track (NFT) project types might conceivably include some off-grid projects, such as large-scale generation for industrial facilities that choose to self-generate their electricity. Additional work would be needed to examine baselines for such projects.

2. Electricity Baseline Issues and Options

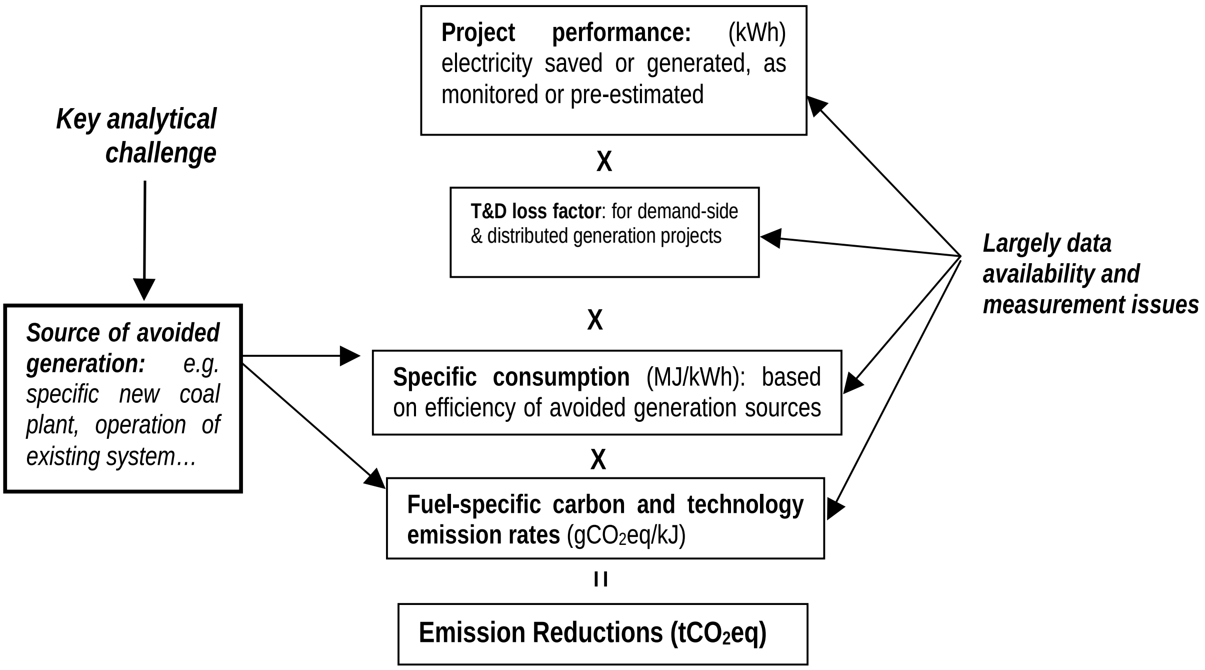
This section reviews and evaluates specific options for standardising electricity baseline emission rates. It begins by introducing a simple framework that identifies the key analytical challenge – identifying the generation resources avoided by a CDM project (i.e. "what would happen otherwise"). It discusses the fundamental question of whether the *avoided generation* is on the "build margin" (i.e. replacing another new source of electricity) or "operating margin" (i.e. affecting the operation of current or future power plants). It then outlines a few key issues –project/baseline boundaries, baseline dynamics (updating and revision), and geographical aggregation – before evaluating specific standardised baseline methods for typical on-grid projects. Finally, it suggests an approach for a couple of special cases, i.e. brownfield and off-grid projects, which require somewhat different baseline approaches. The case of projects displacing a *specific* project is also discussed.

2.1 Framing the analytical question

It is generally straightforward to determine how much electricity a GHG mitigation project in the electric power sector generates through metering and monitoring. However, determining how a project's generation affects the operation or construction of other electricity plants on an interconnected grid is another challenge altogether. If one could simply say that project X avoids electricity generation from existing electricity plant Y, then the calculation of emission savings associated with project X would be a simple calculation. Only the amount and type of fuel burned at plant Y (or a generic figure for that plant type), and the appropriate emission factors for that fuel and technology need to be determined. These data are relatively well established and available. However, real-life situations are rarely so straightforward.

Figure 2-1 shows how to calculate emission reductions from grid-connected electricity projects. It illustrates the two types of challenges in calculating project emission reductions: those of data availability or measurement (such as fuel carbon contents, plant efficiencies or specific consumption), and those of a more fundamental analytical nature, i.e. what source(s) of generation are actually displaced by a project. While much of this section focuses on options for determining avoided generation sources (highlighted box), the feasibility of these options is often driven by data constraints.

Figure 2-1. Key variables in determining emission savings for grid-connected electricity projects



2.2 Build, operating, or combined margin? A key question for electricity baselines

Many studies have pointed out the need for emission baselines to take into account what is happening at the *margin* (rather than on *average*), as it is a better reflection of "what would happen otherwise" (e.g. Lazarus et al., 1999; and OECD/IEA, 2000). But there are different methods and approaches to estimate the *margin*.

The choice of baseline for electricity projects often revolves around the choice between *operating margin* versus *build margin*, and the question of which best represents the source(s) of avoided generation.

Some baseline scenarios or methodologies reflect the belief that a given project will have no effect on other power sector investments, either because it is too small or because it brings additional investment to a sector that is short on capital for new power plant investments. These scenarios are *operating margin* scenarios, in that they assume the principal effect of a new project would be on the operation of current or future power plants.

In contrast, some baseline scenarios and methodologies implicitly presume that a proposed project is an alternative to investing in another specific new source of electricity (e.g. "if not this geothermal facility, then a coal plant would have been built") or some other unspecified source of electricity. Or they may assume that rather than cancel the planned construction of another facility, a project merely delays its online date. In fact, this "delay effect" is a reasonable assumption where a) there is a planned or unplanned sequence of new facilities to be built, and b) the timing of construction is affected by the need to balance supply and demand, either through maintaining the reserve margin above a threshold level (in planned systems) or through the price signals created by rising demand that motivate new investments. By increasing generation or reducing load, a new project will increase reserve margins or dampen price signals, delaying the timing of the series of planned or market-induced investments in new power supply, as illustrated in Box 1. [13] All of these scenarios are, in essence, *build margin* scenarios, since they assume the project affects what and/or when new facilities will be built.

It is important to consider the "delay effect", especially given that it is more likely to occur under most power sector circumstances than the "cancel effect" (i.e. not building another plant altogether)[14]:

- the effect should be manifested in the delayed construction, even if slight, of a series of new facilities, not just the next plant in line; therefore,
- build margin baselines should thus ideally reflect a composite of power plant investments, and not necessarily a single one;
- simple baseline scenarios pointing to a single power plant or power plant type may be insufficient for developing robust baseline emission rates, except in situations where a single plant type is dominant for new construction (for example, as has been the case for natural gas combined cycle plants in some regions).

As a consequence, unless a project can be clearly shown to displace another specific power plant (e.g. a high-efficiency coal plant being built instead of a lower efficiency one at the same site), standardised *build margin* baseline emission rates that are drawn from a mix of likely capacity additions are preferable to "single plant" baselines.

Another implication of the delay effect is that, up until the time at which the delay effect takes hold – and it could take several years if there are plants with long lead times under construction, the CDM project could have an effect only on the *operating* margin. This in turn suggests that the ideal baseline approach might be one that combines both the *operating* and *build* margin effects, evolving from the former in early years, toward the latter in later years.

As shown, later in this section, standardised electricity baseline approaches proposed by various parties generally fall into either the operating or build margin category, or represent some combination of the two, by reflecting both operating and build margin effects. First, however, we turn to some key aggregation and boundary issues that will influence how these methods can be applied.

[13] Investments in transmission may also be affected, such as interconnections that would enable power purchases from other grids, or simply the bulk or local transmission needed to get new supplies to the power market. Major transmission interconnections for increasing power imports should ideally be considered as one of the marginal options in a build margin analysis, but can present tricky baseline aggregation questions.

[14] It can be argued that CDM projects, especially smaller ones, will have no effect whatsoever on other plant construction in situations where local price signals and reserve margins are not the main drivers for new investment. Indeed in many countries, capital availability and other intangible factors (e.g. politics) may be a principal driver. These situations will generally be difficult to identify and may be short-lived. Moreover, as in other situations of supply-demand imbalances, such situations pose a more fundamental additionality question regarding whether a new CDM project will supplement rather than displace electricity generation and its emissions (see e.g. USDOE/SAIC, 2001). Some have argued that projects that increase overall electricity supply above the counterfactual level should still be eligible, given that simultaneous increasing energy service provision and orienting power sector towards lower carbon development is consistent with the sustainable development principles of the CDM. (PCF, 2001b)

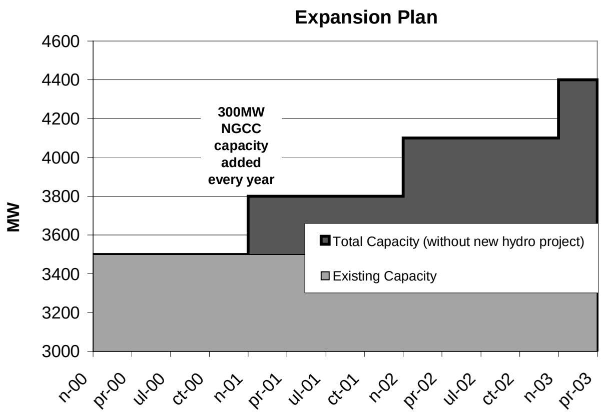
Box 1. The delay effect: how even small projects can affect new construction

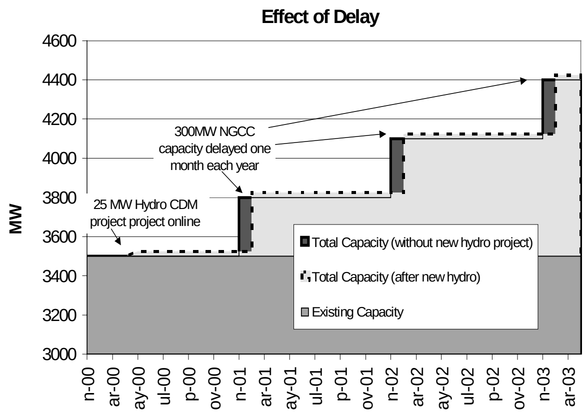
It is sometimes argued that emission reduction projects, especially smaller energy efficiency and renewable energy projects, will have little or no effect on what plants are built or retired, and thus avoid generation only from existing plants. Such an argument suggests that for smaller projects the *operating* margin provides a more relevant baseline than the *build* margin. However, it is worth examining this assumption more closely.

Consider, for example, a power system of 3500 MW total generating capacity. Due to rapid growth in electricity demand, a new 300 MW natural gas combined cycle (NGCC) plant is expected to be built approximately every 12 months. This expectation might be based on an expansion plan in centrally-planned single utility system (e.g. Mexico or India), or on expected response to price signals in a competitive wholesale electricity market (e.g. Chile or Argentina). This expansion is reflected in the chart on below.

Now assume a new 25 MW hydro project comes online, as shown by the dotted line beginning on the right of the second chart below, which shows total system capacity versus time. (In this fictive example, the hydro plant begins operating in May of year 0.) This project adds about 1/12th the electricity of a new NGCC plant, a small amount, but sufficient to delay the need for this new plant by one month. In a planned system, delaying the series of plant additions by one month could save the utility (and its ratepayers) a considerable sum in plant operating costs and interest payments on the capital required. In a fully-functioning competitive market situation, the addition of the hydro plant will delay the time at which supplies get tight by about one month, and dampen price signal sufficiently for investors to delay their investments by one month on average.

If this delay does occur, as shown in the right-hand chart, the whole series of expected plant additions is put off, each by about one month. By displacing a 300 MW NGCC for one month each year, the 25 MW hydro plant is avoiding the equivalent of 25 MW of NGCC each year (300MW x 1/12 year). In other words, in this simplified example, there is a one-to-one correspondence between the amount of credit generation and avoided generation at the *build* margin, beginning with the delay of the first NGCC plant. Reality of course is more complex. Due to the inertia of power system investments, it may take a few years for a project to actually have this effect, and in the meantime it might be affecting only the operating margin. Yet the effect demonstrated by this example should hold in most power systems: even small projects should have some effect on displacing electricity generation from new plants on the *build* margin.





2.3 Baseline dynamics and crediting lifetimes

There are several issues of baselines "dynamics" that have been discussed extensively in the literature (OECD/IEA, 2000; Lazarus, Kartha, and Bernow, 2000), most notably:

- Should a standardised baseline be determined on an *ex ante* or *ex post* basis?
- How long should a given ex ante baseline emission rate apply before it is subject to possible revision (or ex post method subject to change) for a given project (crediting period)?
- Should an ex ante baseline emission rate have single fixed value or perhaps decline over time?
- How often should ex ante standardised baseline emission rates be updated for new projects?

While many of these questions may still not been fully answered for JI/CDM projects, they can at least be put to rest for the time being in light of recent COP decisions, and some can be answered by relying on the recommendations of the May 2001 UNEP/OECD/IEA baseline workshop (UNEP/OECD/IEA, 2001) and insights from baseline studies. The COP decision on crediting periods[15] means that CDM project proponents will have the choice between up to three consecutive 7-year crediting periods, with baseline revisions possible at the start of the second and third periods, or a single 10 year crediting period. In both cases, no emission reductions occurring beyond year 21 or 10, respectively would be eligible for credits. These decisions can be interpreted as a compromise on the question of baselines, between investor certainty (providing fixed periods for crediting) and environmental integrity (by fully discounting any emission reductions beyond years 10 or 21 in response). For the purpose of this paper, these decisions are interpreted as implicitly favouring *ex ante* baselines, which can only be revised for a given project in years 8 and 15, if the proponent selects the 21-year crediting period. This seems consistent with the COP7 decision on the CDM stating that "any revision to an approved methodology shall only be applicable to project activities registered subsequent to the date of revision and shall not affect existing registered project activities during their crediting periods"(Decision 17/CP.7, paragraph 39 of the Annex). These *ex ante* baselines could take the form of either specific emissions intensities or algorithms for calculating emissions intensities. While there may still be scope for an *ex post* approach, which can be quite well suited to standardised *operating* margin baselines, it is not further considered here.

2.4 Geographic aggregation

As noted above, experts at the May 2001 UNEP/OECD/IEA baseline workshop concluded that for grid-connected projects, baselines should account for regional, national, or sub-national grid characteristics, as defined by transmission, power pooling, or other operational considerations. Ideally, then, electricity baselines should be specific to individual "grid areas", and in that way more accurately reflect the generation (and if relevant, T&D losses) that a project would most likely avoid, based on its location. Differences in carbon emissions intensity among distinct regions of a country can often be quite significant (example here, e.g. North/South Brazil, East/West China, North/South India), due to different resource availabilities and fuel prices. The challenge is to find a workable definition of a grid area that can be based on data suitably disaggregated to allow baselines to be calculated in this manner.

The grid area can be defined by transmission constraints planning areas, power pooling agreements, or commonly accepted norms for what constitutes a well-interconnected system that is operated in a joint manner. A country may comprise more than one such grid. For example, Mexico currently contains four semi-autonomous regions for grid operation and power plant operations. Largely due to limited

[15] Decision 17/CP.7. www.unfccc.int/cdm/rules/modproced.html

transmission connections among them (Baja California South, Baja California North, the Northwest, and the rest of the country), and the availability of detailed data, baselines could be developed separately for each grid (ATPAE/USAID, 2002). Or multiple countries may plan and operate their electricity systems in a joint fashion. There are several power pooling associations around the world, including SIEPAC (Sistema de Interconexion Electrica Para America Central with Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, Panama) and SAPP (the South African Power Pool with Botswana, Lesotho, Mozambique, Namibia, South Africa, Swaziland, Zambia, Zimbabwe). Though such associations often facilitate power sales and joint resource development, they rarely act to operate or dispatch the entire system in a joint manner. The appropriateness of aggregating baselines to regional power pool levels needs to be evaluated on a case-by-case basis, and, most likely, to be based on the mutual consent of all countries involved.

Therefore, we recommend that while the default level of geographical aggregation be at the country level, host countries, for the purposes of electricity baselines, be allowed to: a) define separate sub-national grids; b) combine with other countries with whom power pooling or other joint planning/operation agreements exist. The resulting *grid area* definitions would need to be supported by evidence of: management of the individual grid areas on joint (multinational) or separate (sub-national) basis; and adequate transmission interconnections (multinational) or significant transmission constraints (sub-national).

2.5 Project boundary issues

Another fundamental question is what project boundaries to assume for electricity projects, i.e. what emissions and emission sources should be counted. Since electricity projects can result in emissions reductions or emissions savings distant from the site of project activity – e.g., a project to replace a fossil fuel with biomass fuel may cause the absorption of carbon in a distant forest – geographic and temporal limits for emissions accounting or “boundaries” are necessary. The question of which emission sources to include in the accounting for emissions reductions has been widely discussed (WBSCD/WRI, 2001; OECD/IEA, 2000; Lazarus and Kartha, 2001). It is a question that relates equally to the project and its baseline, and has important implications for how projects are monitored. In fact, a separate OECD/IEA Information Paper (Ellis, 2002) delves into this question in much greater detail, and thus only some summary comments are presented here.

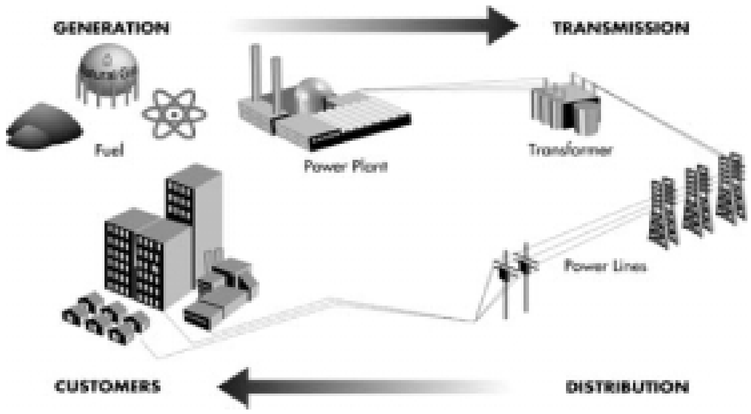
Various principles have been suggested to guide which emission sources and sinks to include:

- **Materiality (or “significance”):** By this principle, emissions sources and sinks should be analysed only if they will significantly affect the calculation of the project’s total emissions impacts. The CDM rules elaborated in the Marrakesh Accords state that project boundaries must encompass “emissions by sources of greenhouse gases [...] that are *significant*...” (Decision 17/CP.7, paragraph 52 of the Annex). A materiality (or “significance”) threshold (e.g. > 5% of total emissions for small, and > 1% for large projects, as suggested at the May 2001 UNEP/OECD/IEA baselines workshop) might assist proponents in knowing which effects to neglect. Putting such a threshold in effect might require first preparing simple estimates, providing default assumptions, and appealing to expert judgement to set general guidelines. Ellis (2002) rejects the idea of defining “materiality” or “significance” in terms of a project’s **total** emissions, in favour of defining it in terms of the project’s **largest** emissions source.
- **Control over emissions and the maintenance of proper incentives:** By corresponding to those emissions over which the proponent can exercise control, system boundaries can provide opportunities and incentives to achieve emissions reductions whether on-site or off-site. For example, narrow boundaries could create perverse incentives, for example if credits were claimed for activities that simply outsourced emissions (e.g., by replacing on-site with grid electricity

generation that was not accounted for[16]). The project boundaries agreed in the Marrakesh Accords encompass "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". However, control over emissions can be defined either of two ways: equating control with proponents' ownership or management of facilities (WBSCD/WRI, 2001) or considering control to mean 'control over whether or not emissions occur'.

- **Leakage.** To account for projects where the stated boundary does not encompass certain potentially significant emissions sources, the Marrakesh Accords define leakage "as the net change of anthropogenic emissions by sources of greenhouse gases which occurs outside the project boundary, and which is measurable and attributable to the CDM project activity". The CDM rules further state that "Reductions in anthropogenic emissions by sources shall be adjusted for leakage", and call for guidance on "methods for the ex post evaluation of the level of leakage" (Decision 17/CP.7).
- **Avoidance of double counting.** Multiple proponents should not get credit for the same emissions reductions. For a simple example, one proponent switching a boiler from coal to biomass should not claim upstream benefits for reducing coal-bed methane emissions, if a second project developer simultaneously claimed credits for methane capture at coal mines. Double counting will be limited if either a) baselines and project boundaries are defined narrowly, excluding most off-site emissions sources; or b) each project's baseline takes into account the impacts of other projects. For example, the boiler project could either a) ignore upstream methane emission savings or b) assume post-capture methane emission rates.
- **Cost-effectiveness or practicality:** The wider the boundaries, the more complete the accounting of a project's emissions impacts, but the greater the costs. Boundary definition affects not only the baseline assessment, but also the monitoring and verification activities. Therefore, to define a boundary in a cost-effective manner, authorities must balance the importance of including a particular emissions impact against additional costs of measurement.

For accounting purposes, it is useful to distinguish emissions sources and sinks into four categories (ERUPT, 2001):



1) direct on-site (e.g. fuel combustion and process emissions on the project site)
2) direct off-site (e.g. emissions from grid electricity (in the case of energy efficiency projects) or district heat, and other upstream and downstream life cycle impacts)
3) indirect on-site (e.g. rebound effects such as increased heating that may result from of an insulation program)
4) indirect off-site (e.g. project effects that are typically referred to as leakage, either negative or positive, such as economy-wide response to project-induced changes in market prices or project-induced increases in the penetration of low carbon technologies in other regions)

[16] Although this example is unlikely given that grid electricity emissions are usually taken into account.

It is generally accepted practice to include all direct, on-site CO_2 emissions, and similarly to include those direct off-site emissions related to electricity or district heat production (Ellis, 2002).

It makes sense for some types of projects to account for avoided transmission and distribution losses (T&D) in their baseline (Martens et al. 2001b). For example, CERUPT (2001) guidelines allow small-scale renewable energy projects supplying electricity to a low-voltage electricity grid as well as energy efficiency projects to count the benefits of avoided technical transmission and distribution losses. This should also apply to other distributed generation projects. Including these avoided T&D losses can add from 5-20% in emissions credit, depending on the condition of local distribution systems (thus encompassing all direct emissions indicated by the arrows on the right-hand figure). But for other grid-connected projects, T&D would not need to be counted as the losses would be the same for the CDM project as for the project "that would happen otherwise" – essentially creating a "wash".

Other direct off-site emissions, as illustrated in Table 2-1, are rarely included in *baseline* emission calculations, even though they may be in *project* emissions calculations. In other words, upstream methane releases might be counted for a project that generates electricity from natural gas, whereas a wind project might not include the methane emissions associated with the natural gas generation assumed to be in the mix of avoided electricity sources forming the baseline. We recommended this approach (i.e. excluding direct off-site emissions) for electricity supply projects, as it is practical as well as conservative[17].

Indirect emissions are typically more difficult to quantify. Though they can have major impacts on calculated emission reductions for some land-use related projects (e.g. leakage in the case of some avoided deforestation projects), these will rarely have a predominant impact on electricity projects (Lazarus and Kartha, 2001). Often leakage effects, especially for projects that overcome barriers to cost-effective low carbon technologies, can be positive, due to the "free-driver" impacts (or "spillover effects") of popularising new practices.[18] Again, however, these leakage examples refer to impacts of a *project* itself, rather than leakage impacts generally associated with the *baseline* or avoided generation sources (i.e. the plants on the operating and build margins).

Therefore, for reasons of practicality as well as conservatism, we recommend that only transmission and distribution losses be accounted for in terms of indirect emission sources for energy efficiency projects and distributed generation projects. It is important to note that this recommendation applies only to *baseline* calculations. For *project* emission calculations (via monitoring), broader boundaries may apply, although some parallel treatment may be warranted for the emissions calculated in the baselines and those monitored from the project. Some indirect and off-site emissions could also be added to the baseline on an *ex post* basis, as the result of monitoring and verification work, but this warrants further examination.

In terms of calculating a T&D loss factor (total generation/total delivered electricity), we recommend using the locally available data for the grid area, as defined (see previous section), and where absent to use nationally reported data. A more refined approach should be taken for high voltage energy efficiency projects, accounting only for transmission losses where the separate T loss & D loss data are available. Non-technical losses (i.e., theft) at the distribution level may be significant in some countries but should <u>not</u> be counted in calculating the T&D losses.

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[17] However, electricity demand projects should count direct off-site emissions from reduced grid electricity.

[18] A good example is the impact of AIJ projects in the Baltic States to upgrade boiler efficiencies and promote fuel switching from fuel oil to gas and biomass. (Kartha et al, 1998)

Table 2-1. Partial list of direct, on-site and off-site emission sources that might be significant

Projects avoiding↓	**Boundary impacts**	**Issues to consider**	**Current typical practice (for baselines)**
Delivery of electricity across			
Distribution "D"(low voltage) wires	Average avoided distribution losses	Applies to most residential and commercial efficiency and distributed generation projects	Include combined T&D loss fraction, based on national loss figures (e.g. CERUPT/ERUPT) (Do not include "non-technical losses")
Transmission "T" (high voltage) wires	Average avoided transmission losses	T losses typically a small fraction of overall T&D losses. Efficiency or CHP at large high voltage industrial customers usually avoids only the T losses.	
Grid electricity production from:			
Coal	Coal-bed methane emissions, where release rates are high	Potential for double-counting with methane capture projects	Rarely, if ever, counted.
Natural gas	Methane releases from T&D, production, and storage	Potential for double counting with methane capture projects.	Rarely, if ever, counted.
Oil	Methane from associated gas venting and flaring, especially where rates are high.	Given the global oil market it may be impossible to effectively link consumption to specific production sites.	Rarely, if ever, counted.
Biomass	Carbon flows and energy use in feedstock production and transport.	Impacts from land conversion, and harvesting of biomass feedstock.	Mixed. Often argued that sustainably harvested biomass has zero net C emissions.
Hydroelectric facilities	Methane emissions where sited on terrain with decaying biomass[19]	Unlikely that project will avoid construction of a specific hydro plant. Large uncertainties related to CH4 emission calculations.	Limited experience.

2.6 Operating margin (OM) methods

As mentioned earlier, the operating margin approach presumes that a project's predominant effect is to modify the operation of existing power plants. Operating margin approaches have been used for numerous emission reduction projects.[20] "True" operating margin approaches require information to identify which plants are the last to be "fired up" to meet demand at any given time. This information can include: historical dispatch data (which plants were operated during which hours), stacked-resource load curves that assemble this data in merit order, or the hourly operating cost of different plant types (or their bid prices in competitive environments). This information is available in a number of countries, though in many access is restricted via confidentiality agreements. Where these data are unavailable or simpler approaches are desired, more creative approaches have been used to assess the operating marginal resources.

[19] Though hydropower is generally considered to be a zero-carbon resource, flooding of reservoirs containing substantial biomass (subject to anaerobic decomposition) and can lead to significant methane emissions, especially where the ratio of flooded area to power production is low (e.g. < 0.5 W/m^2) (Rosa and dos Santos, 2001).

[20] Examples include: Ilumex DSM/Mexico (World Bank AIJ), PROCEL DSM/Brazil (GEF), Liepaja Landfill gas/Latvia (PCF), Chacabuquito Hydro/Chile (PCF), Brazil-Aspen Forum case studies, Chile Dona Julia Hydro and Aeroenergia Wind/Costa Rica (USIJI).

Below we discuss and then compare four discrete operating margin approaches, beginning from simplest to most complex. All represent algorithms or methodologies (e.g. using models) that can be applied periodically (e.g. annually) within a host country to develop *standardised baseline emission rates* (gCO2e/kWh) for projects.

These approaches provide fixed algorithms for calculating a baseline emissions rate. The data required by each algorithm is discussed below, as well as the information sources from which the data can be obtained. Such algorithms would provide an unambiguous formula upon which project developers can base projections of the future CERs their project might earn. This is likely to present limited risk to investors, since the baseline emission rates are unlikely to vary much on an annual basis given the inertia of power systems, especially larger ones.[21]

OM1 - Generation-weighted average emissions rate (all plants). The prime example of a "quick-and-dirty" approach to assessing the operating margin is simply to assume that a project avoids a proportional fraction of all generating units on a system. The required data are usually available within host countries, and if not, they can be drawn from international data (e.g. IEA). The results are easy to calculate on an annual basis. The most obvious concern with this approach is that it can bias the baseline toward existing baseload plants and other low running cost power plants (e.g., hydro, nuclear, and geothermal) that provide a considerable amount of electricity in many countries; these units are the least likely to be displaced by new projects. This can introduce considerable inaccuracy especially in centrally dispatched systems where the carbon intensity of baseload units (say hydro and nuclear) is far different than that of the higher cost generation resources that are more often on the operating margin (e.g., oil and gas units). For such reason, Ellis and Bosi (1999) concluded that this approach would not provide a particularly credible baseline.[22] OM1 is not recommended for use, except as a basis for other methods, discussed below.

Data: Table 2-2 shows the data required for this method, and the recommended data sources. Data are typically available at either of three levels: A) individual power plants; B) fuel/technology type (natural gas/steam turbine, natural gas/combustion turbine, etc.); or C) fuel type (coal, oil, gas, hydro, etc.). The most accurate approach is to use level A data, with B as second best. Level A generation and fuel consumption data are available in many countries, though often only from electric utilities.[23] Level C, or aggregate generation and consumption data by fuel are available from the IEA, and can be used where local data are unavailable. IEA data, however, are only available at the national level, and if relied upon, would not allow the use of sub-national grid areas.

[21] Data from Mexico and other countries demonstrates the limited variation of operating margin (using method OM2). Circumstances under which the operating margin might shift significantly (e.g. +/- 10%) include: unusually wet or dry years on a largely hydro system, very small power systems, or dramatic shifts in relative fossil fuel prices. Steps can be taken to limit investor exposure to weather fluctuations (e.g. by normalizing to average water years).

[22] Some analysts have even argued the straight system average approach is best suited to competitive energy markets, where generators compete to sell electricity on the basis of strategic bid prices rather than operating costs alone (as in traditional systems). The Alberta (Canada) Emissions Quantification Working group, for example, decided in favour of a simple system average, finding "true" operating margin methods to be too complex, expensive to implement, and subject to multiple interpretations (Lazarus and Kartha, 2001). Such competitive markets however are currently only found in a handful of non-Annex I countries.

[23] For example, ATPAE/USAID (2002) present baselines calculated based on plant-specific data collected from the system operator, CENACE, for Mexico. Sathaye et al (2001) present standardised baselines calculated on plant-specific data for South Africa, part of India, and Brazil. Lazarus, Kartha, and Bernow (2000) also show baselines calculated for India, South Africa, plant-specific data collected by SAIC for plants in India, South Africa, Jordan, and Venezuela. All of these examples demonstrate that such data can often be obtained locally. Costs of obtaining this data are not specified, however.

Algorithm: Simple generation-weighted average emission rate across the most recent year for which data are available.[24]

Examples: This method has been applied for the US Voluntary Reporting (1605b) program (state-level averages), and some Canadian (GERT) projects.

Table 2-2. Data requirements associated with the operating margin method (OM1)

(level A = by individual plant; B = by fuel/technology type; C = by fuel type)

Data Required	**Data Sources** (in suggested priority order)
Generation data for all plants in each grid area for a recent year ($kWh_{generated}$)[25]	• National ministry • Relevant electric utility or system operator • International data (IEA – only available at level C, national level)
Specific fuel consumption, heat rate or efficiency (kJ_{fuel}/kWh), often reported as total fuel consumption by plant, which can be divided by generation	• National ministry • Relevant electric utility or system operator • IEA data (for level C analysis only) • International sources (e.g. see CERUPT's use of data from the World Bank/Oko Institute's Environmental Manual)
Fuel specific carbon content (gCO_2e/kJ)	• National ministry • Relevant electric utility or system operator • Fuel suppliers • IPCC National Inventory Guidelines
T&D loss factor ($kWh_{generated}/kWh_{delivered}$), calculated at the grid level	• National ministry • Relevant electric utility or system operator • International data (IEA, only available at national level)

OM2) Generation-weighted average emissions rate, **excluding must run/ low running cost facilities.** By excluding baseload resources that are least likely to be on the operating margin and thus displaced by a new project, this approach partly addresses the principal concern with method OM1 (i.e. inaccuracy). A system average can be constructed that excludes facilities that are both must-run and low running cost /resources such as hydro, geothermal, wind, low-cost biomass[26], and solar; it is *prima facie* unlikely in most systems[27] that these resources would operate less in response to new generation from a CDM project.

[24] A three-year rolling average can also be used where annual variations are significant, in response to major swings in fuel price, demand, or streamflow (for hydro systems).

[25] Net plant generation, i.e. net of plant own use or parasitic losses as most typically reported, rather than gross, should be used.

[26] Examples of low cost biomass resources are bagasse residues burned at sugar refineries, or paper and pulp residues burned. While some residues may have an opportunity cost (e.g. for use in paper, fiberboard, or other commodities), this is typically beyond the utility operator's decision framework. Examples of higher cost biomass resources would be dedicated crops, such as woody feedstocks, or residues that require costly transportation to power plant sites.

[27] The notable exception would be systems where these comprise a majority of the resource mix. According the World Commission on Dams, 24 of 150 countries rely on hydropower for over 90% of their electricity. (http://www.dams.org/report/report_factsheet.htm) One simplified option for addressing this concern is to exclude a fixed percentage of these resources (e.g. the first 50%) from the calculation.

The criteria to limit the "excluded" to only renewables is based on the fact that they have no associated fuel costs[28].

The resulting baseline emission rate under this approach would represent an average of all coal, oil, natural gas, and higher-cost biomass resources. It would be a mix of both baseload and peaking facilities, which is appropriate given that most projects will avoid a mix of both types. Within this mix, however, it would not give greater weight to the higher-running-cost plants (in each time period) that are more likely to be reduced in operation. Typically, these are the plants facing higher fuel and/or O&M costs, due to lower efficiencies, higher fuel costs, or higher O&M requirements, and are frequently older steam turbine plants that have relatively high carbon emission rates.[29]

Data: The data requirements for this method are identical to OM1 above, with the exception that no data is required for the low-cost and must-run facilities, but some additional information is needed to identify these facilities (e.g. low-cost biomass vs. high cost biomass).

Algorithm: The algorithm analogous to OM1 above, again with the exception that low-cost and must-run facilities are excluded.

Examples: This approach is embodied in the CERUPT standardised baseline methodology (CERUPT, 2001), and has been recommended for small projects in Mexico (ATPAE/USAID, 2002).

OM3) Dispatch decrement analysis. Actual dispatch data, which shows generation by each plant in a system each hour of the year, provides empirical evidence of the actual mix of resources that are turned on and off across the year in response to increasing and decreasing loads. However, simply looking at dispatch data to discern the highest cost plant type across the year (e.g. as reflected in stacked-resource load curves) is generally insufficient. In larger systems especially, many different plant types may decrease production concurrently as loads decline, not just the apparent highest cost plant type. This is because of transmission constraints, variation of fuel and operating costs by plant locations and time of year, and cycling considerations. It is also important to exclude storage hydro and related storage resources, which might appear to be on the margin as they fluctuate in production in response to changing loads. However, they tend to operate more during high load periods because of their flexibility, not due to higher running costs, as would be the case for other intermediate and peaking resources. In response to the addition of a new CDM project, hydro resources are unlikely to reduce overall kWh of production -- as this amounts to wasting free electricity "over the dam" – but instead might simply shift the hours of power generation.

Data: This approach requires all of the data shown in Table 2-2 at the plant level (A), with the generation data provided by plant on an hourly (or periodic) basis. Such data are usually kept by the central utility or system operator. It is rarely published[30], and in some instances is treated as confidential, but can otherwise be obtained by agreement.

Algorithm: Determine all plants that reduce generation moving from higher to lower load hours, excluding hydro, pumped storage, and other storage-capable technologies. Calculate hourly (or other

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[28] Due to their relatively low running costs, nuclear and coal plants are most often run as baseload plants, however, their operations may still be affected by CDM plants. The issue of which resources to exclude likely deserves closer examination, which could be done through case studies, for example.

[29] In the case of Mexico, for instance, these are predominantly oil-fired steam plants with emission rates of 0.83 gCO2/kWh.

[30] One exception is Chile, which makes its dispatch data available through the internet for a fee.

period) weighted average emissions rate across entire year, and from this calculate hourly (or other period) marginal emissions rate.[31]

Examples: Dispatch analysis approaches have been used for several GHG mitigation projects, including the World Bank/AIJ/GEF ILUMEX lighting DSM project in Mexico, the PCF Liepaja landfill gas utilisation project in Latvia, and several NESCAUM pilot projects in the Northeastern US. A simplified load curve method was developed and applied to several Brazilian case study projects by researchers at LBNL and the University of Sao Paolo for the Brazil-Aspen Global Forum. (Meyers et al, 2000) The suggested method here has been applied in Mexico, and overcomes some of the weaknesses of the simplified methods by capturing the avoided generation effects across multiple plants (Lazarus and Oven, 2002).

In sum, this method offers a more accurate, empirically-based operating margin than the previous average methods (OM1 and OM2). However, data and analytical requirements will limit its application to those countries with utilities willing and able to share the required information.

OM3a) Time-of-use dispatch decrement analysis. This variant involves calculating the avoided generation as in OM3 but grouping hours into typical load categories such as seasonal, peak, shoulder, and base periods. In principle, this approach provides greater accuracy for projects with variable load profiles, and may reveal greater benefits for peakload reducing projects where peakload generation is particularly carbon-intensive (e.g. using diesels or combustion turbines in a more inefficient on/off mode). The method is relatively costly as it requires not only calculation of periodic or hourly emission factors, but it also requires tracking of project generation or loads (in the case of energy efficiency) on an hourly or periodic basis, rather than simple annual accounting. The benefits of this method will only be significant if *both* system average emission rates and project generation or loads vary significantly across hours of the year. Otherwise, the average methods above are likely to yield similar results, at a fraction of the overall effort.

OM4) Dispatch model simulation. A dispatch or "production cost" modelling approach may be the most sophisticated and accurate approach. A dispatch or production costing model simulates the complex operations of the electric system in response to a decrease in demand or an additional supply from a new project. One kWh of electricity savings may affect the operation (and efficiency) of several plants, some on the margin, some not. A dispatch model properly configured to represent storage hydro resources will also provide a much better picture of how a hydro-based system will respond to changing generation requirements. The dispatch modeling method, however, may be considerably more labour-intensive and costly to implement. In addition, it can be non-transparent, and can require advanced technical capacities for effective review. External validation of the model and model inputs are important, since results can be highly sensitive to fuel price and other assumptions.

Data: Utilities that use dispatch models utilise a comprehensive data set that accounts for the various financial parameters, technical performance, and demand characteristics of their grid. No additional data will be needed to develop a baseline other than what is already assembled for the normal use of the dispatch model. But utilities rarely make publicly available their dispatch model with the entire set of data and assumptions.

Algorithm: The dispatch model can be run once a year to yield standardised baseline emission rates for one or more load profiles (e.g. for a plant that operates year-round as baseload generation and another that operates more heavily during peak periods).

[31] See Lazarus, 2002 for an example of this method in practice.

Table 2-3 compares the operating margin methods against each other (rather than against the fundamentally different *build* margin methods discussed below), using the main baseline criteria discussed in section 1. The shaded cells indicate what might be considered decisive criteria. The system average method (OM1) is presently too inaccurate, especially in systems with large amounts of low-cost hydro resources to be considered widely applicable, a conclusion consistent with previous OECD/IEA reports (Ellis and Bosi, 1999). The dispatch data and modelling approaches (OM3 and OM4) might be usefully applied on a country-specific or grid-specific basis. (See Category 3 in the next section). However, both approaches present data and model constraints that will render them inapplicable (at least for the time being) in many countries.

Therefore, we recommend that for the purposes of developing widely applicable standardised baselines, the system average method excluding low cost/must-run resources (OM2) be used, *if and where operating margin* approaches appear appropriate (see combined approaches below). Prima facie, it is difficult to determine whether the OM2 method will yield results that are significantly more or less conservative that the most accurate operating margin methods (OM 3 and 4). In Mexico for instance, the result for OM2 was within 2% of OM3 for the main national grid and one of the smaller grids -- 0.80 vs. 0.81 gCO_2/kWh). In one of the other grids (Baja California North) the OM3 method yielded a baseline 70% higher (1.7 vs. 1.0 gCO_2/kWh). To have a better understanding of the implications of the various OM calculations methods, more case study analysis would be needed.

Table 2-3. Comparison of operating margin methods

	System Average (OM1)	**Average excluding low cost/must run facilities (OM2)**	**Dispatch decrement analysis (OM3)**	**Dispatch model simulation (OM4)**
Accuracy	Low	Improved	Higher, though can be difficult to determine true marginal resources in hydro-dominated systems	Depends on assumptions
Data Availability (Practicality)	High	High	Limited. May be considered confidential.	Limited model availability.
Cost-effectiveness	High	High	Perhaps for large peakload saving projects when using time-of-use approach	Potentially costly model runs feasible only if project and credit flow is very large.
Wide applicability	High	High	Limited	Low
Transparency	High	High, though deciding what to exclude introduces judgement and potential bias	Medium to high, if calculations are clearly presented.	Low, given the dependency of results on detailed and often poorly documented model parameters.
Conservative (relative to most accurate OM methods 3 and 4)	No, especially in systems with a large proportion of old fossil fired plants. In systems with considerable low cost, low C may actually dissuade investment.	Must be judged on grid-by-grid basis.	N/a	N/a
Consistency	High	High (providing there are common definitions of what facilities to exclude)	High, providing data is adequate	High, providing models are well-calibrated to actual circumstances
Reproducibility	High	High	High if access to necessary data	Medium (only if access to the models)

*Shaded areas show critical drawbacks from the OM methods.

2.7 Build margin (BM) methods

The *build* margin approach opens up the difficult counterfactual question that the *operating* approach conveniently avoids. The *build* margin approach makes a "best guess" as to what type of electric facility would have otherwise been built (or built sooner, insofar as GHG mitigation projects are likely to delay rather than displace other new plants) had the project not been implemented. Even in well-planned electric systems, it is very difficult to predict the timing and type of new plant additions (beyond those already well into construction). Furthermore, historical experience and current construction activity may not always be indicative of future additions. Especially in situations where new fuel infrastructures are developing or new technologies are emerging (as has been the case with natural gas and combined cycle technologies in several parts of the world, for example), the types of new capacity can vary significantly from year to year.

At the same time, it is a difficult question that must be addressed. As discussed in Section 2.2, there are good reasons to suggest that most CDM projects, small as well as large, will ultimately affect the schedule of new plant additions, and that the net emissions impact of delaying a series of plants can resemble displacing a combination of them. The question then boils down to making a reasonable estimate of what types of plants these will be, given available data, knowledge, and the need for transparency.

BM1) Average of recent capacity additions: This method involves collecting data on the most recent (and ongoing) construction activity and deriving a weighted average emissions rate based on an appropriate cross-section or "cohort" of facilities. While this method has been largely applied to individual GHG mitigation projects in case study contexts, this approach has been subject to extensive analysis and discussion in the literature as the basis for standardised multi-project baselines (Sathaye et al, 2001; USDOE/SAIC, 2001; OECD/IEA, 2000; Lazarus et al, 1999 and 2000). It is also an input to the CERUPT standardised methodology for small-scale projects. Among the key dimensions that have been analysed in the determination of build margin baselines are:

- **Cohort**: Which plant additions should be used to calculate the baseline and should they be derived from historical data or projections? Arguably the appropriate cohort is for the time period when a given project would be most likely to affect new construction, i.e., in the years after a project's on-line date. Expansion plans and forecasts can be used to estimate future additions, and have been applied to baseline calculations (e.g. ATPAE/USAID, 2002). However, plans are subject to major uncertainties, and there are often significant discrepancies among different forecasts (OECD/IEA, 2000). Furthermore, projections and plans lack transparency as they are often founded on models or judgement. As a result much of the build margin analysis has focused on the use of historical capacity additions – and new plants approved or under construction – rather than on plans or projections. (See OECD/IEA, 2000; Lazarus et al, 1999) Several approaches have been used to define an historical cohort, typically based on plants built within a specified number of recent years (e.g. 5 or 10). However, the pace of new construction varies widely among countries. In South Africa, for instance, only one plant has been constructed in the past 7 years (Winkler et al, 2000). In many Eastern European countries (i.e. potential JI host countries), the number of new plants in recent years is also very low, given the slump in electricity demand. Therefore, we recommend that cohorts be constructed from the most recent 20%, or most recent 5 plants, whichever is greater. In countries where supply capacity has been growing 4% annually – a reasonable rate for a developing economy – the 20% threshold is equivalent to the past 5-6 years of growth. We also recommend including plants that have initiated construction (e.g. beyond about 10% total plant expenditures), to make the cohort as up-to-date as possible.
- **Aggregation:** Should different fuel types, technologies, or duty cycles (i.e. peak vs. baseload) be considered separately? Some attention has focused on the use of standardised fuel-specific baselines, (OECD/IEA, 2000; Sathaye et al, 2001). While baselines based on fuel types or technologies do provide an incentive for higher-efficiency projects within a given fuel, they fail to account for the option of switching between fuels. As noted by OECD/IEA (2000), these baselines can raise concerns about environmental effectiveness; and they could, if widely applied, encourage construction of efficient coal plants where other lower carbon fuels may be otherwise competitive. We do not recommend here that fuel-specific baselines be adopted as a standard method, given their limited applicability and environmental integrity concerns. However, they may be useful where detailed baseline studies show that a less-efficient same-fuel technology is being displaced (See Section 3.2.2). Distinguishing baselines based on whether a plant is baseload, peakload, or intermediate, present other challenges. It can be very difficult to categorize many power plants (e.g. single-cycle turbines), which can be operated in any mode, often varying from season-to-season or year-to-year based on supply constraints. Data is also often difficult to find.

Furthermore, it is unclear whether enough CDM projects (other than possibly some DSM) could be classified as "peakload" to warrant separate baselines.

- **Stringency:** Should the baseline reflect average or better-than-average performance relative to the identified cohort? For instance, the baseline can be set to reflect only the top 25% of the plants in a cohort, in order to promote conservatism. Such "stringent" baselines have been examined in much of the literature. Better-than-average baselines have been suggested as a means to reduce the potential for non-additional projects to gain credit, in part because of the notion that truly additional (or generally desirable) projects are more likely to have lower emission rates. While this approach has particular merit in the context of fuel-specific baselines, where the intent is to raise the bar to encourage the highest-efficiency gas, oil, or coal plants, it becomes problematic when the full system cohort includes many different fuel types with widely varying carbon intensities. The South Africa case study in Sathaye et al (2001) illustrates how different percentile choices (10^{th}, 25^{th}, etc.) can yield dramatically different baseline emission rates. Therefore, as discussed further in Section 3, we recommend that instead of relying on stringency to avoid awarding non-additional credits, that more thorough additionality testing or analysis be applied to those project types where the risk of significant non-additional credits is highest. Also, the build margin using the recommended cohort (above) already includes, by definition, plants on the *margin (*as opposed to the *average* of all installed plants.

Data: Data requirements for this approach can be a challenge. First, the online dates and capacity (MW) values for recent additions are needed. These can often be obtained from national ministries or electric utilities. If not, the Utility Data Institute's World Power Plant Data Base -- used in studies by OECD/IEA (2000) and others – does provides an adequate listing.[32] For the plants identified, all of the data items shown in Table 2-2 (generation, fuel consumption, and fuel carbon content) are needed. Plant (A) level data on fuel consumption or efficiency, however, are often hard to obtain, and generation (or load factor) data for newly added plants is often unavailable or unreliable, since it can take many months before a plant reaches its full operating capability. If unavailable locally, efficiencies and load factors can be estimated based on international parameters. For instance, the World Bank/Oko Institute's Environmental Manual[33] contains a database of technology and fuel-specific efficiencies and load factors that can be mapped onto plants for which no local data are available. These data tend to be rather conservative, since often plants perform at lower efficiencies and high carbon intensities in practice (e.g. due to frequent cycling or operation at less than full capacity).

Algorithm: Calculate generation-weighted average emissions rates for the cohort of plants identified.[34]

Updating/dynamics: The emissions rate should be calculated for the year in question (online date of the project *or, if necessary, the timing of the baseline study*). The method should then be applied again 7 years later, with cohort comprising all additions during that intervening period (years 1-7 of the project)[35].

[32] UDI data are subject to some acknowledged gaps (incomplete listing of plants in some countries) that should be evaluated and filled, or alternative data sources created should this method be put into place.

[33] See http://www.worldbank.org/html/fpd/em/model/em_model.htm and http://www.oeko.de/service/em/.

[34] If generation data is unavailable, generation-weighting can be done using default capacity factors by plant type.

[35] The method could, in theory, also be revised more frequently with more recent plant data, but the benefit of such a decision would need to weighed against the additional data updating costs.

BM2) Single, proxy plant type. This method is largely recommended as an alternative where data sufficient for the recent additions method (BM1) are unavailable or otherwise inappropriate. The data will be inappropriate in sectors that are undergoing major changes that render past plant additions largely unrepresentative for new construction. Given its current ubiquity as the resource/technology of choice, natural gas combined cycle technology can be used as a default proxy until market conditions change, unless a country/region has limited access to gas and/ or has generating options that are clearly less costly. The choice of proxy plant can also be determined on a region-specific level as the lowest cost resource.

A weakness of the recent additions approach (BM1) is that historical data is typically 5 to 10 years outdated compared to the capacity additions that a CDM project actually delays or displaces (e.g. assuming a 4-7 year historical cohort, and 1-3 years before a project's impacts are felt on the schedule of new construction). This can be partly corrected if the historical build margin baseline emission rate is revised at year 8 of operation, the year in which baseline must be reviewed for CDM projects opting for the 7 year with 2 renewals (i.e.21 year) crediting lifetime.

Another weakness is the potential year-to-year volatility of build margin approaches based on historical data. For instance, the cohort may contain one large hydro plant that accounts for much of the 20% most recent additions in a grid area. Once other new plants are built, this plant will drop out of the cohort and the resulting average carbon intensity might rise rapidly and significantly.

Despite these weaknesses, alternative methods do not present better options. Use of projections or planning models[36] introduces the potential for inconsistency (among forecasting approaches), non-transparency, and gaming (OECD/IEA, 2000). Simple proxy plant methods (BM2) may be overly conservative in some cases (e.g. where a natural gas combined cycle baseline is used, and coal plants are also a realistic possibility) and inadequately, and fail to adequately reflect local conditions. Therefore, despite its weaknesses, the system-wide recent additions (BM1) approach provides the best build margin method.

2.8 Combined margin (CM) methods

Since most projects will have some effect on both the *operating* margin, especially in the short term, and the *build margin*, especially in the longer term, methods that combine both effects will, in principle, provide a more appropriate baseline. We recommend here a relatively simple *combined* margin approach that draws from elements of the operating margin and build margin approaches described above. More sophisticated approaches are also possible, but do not necessarily provide greater accuracy for the additional effort and cost (see comment in footnote 36).

CM1) Combined margin approach. For most electricity projects, we recommend combining the *operating* and *build* margin methods identified above as most suitable for broad baseline standardisation for the first 7-10 years of a project. For example, in the case of CDM projects eligible for two baseline crediting lifetime options (as per section 2.3), the following baseline calculation are recommended:

[36] For example, electric sector models that can simulate both the construction of new capacity and system dispatch can be run with and without the project in question to deduce a baseline from both build margin and operating margin projections. For instance, in the US, such models have been applied to develop standardised regional baseline emission rates across planning regions. (Cadmus, 1998) Such models lead to an accurate electricity baseline emission rate to the extent that their projections of future behavior are accurate. Model use is labour intensive and costly, and development, maintenance, and external verification of the model is an expensive proposition. Model results may be highly sensitive to key assumptions, and this sensitivity may not be particularly transparent.

- For years 1-7 (projects choosing a 7-year crediting lifetime with the option of renewal) or years 1-10 (projects choosing one 10-year crediting lifetime, without renewal), with year 1 being the first year of project operations: The straight average of the emissions rates of the operating margin and build margin calculated as of year 1. The *operating* margin is based on the system average excluding low-cost/must-run resources (OM2), unless detailed dispatch data or models allow a more sophisticated approach (e.g. OM3 or OM4). The *build* margin is based on historical data for the generation-weighted average of the most recent 20% of plant additions (BM1), or if data are inadequate using the proxy plant method (BM2).

$$Combined\_Margin_{1stCreditingPeriod} = \frac{OM_{year1} + BM_{historical}}{2}$$

- For years 8-14 (for projects choosing 7x3 year crediting lifetime), the baseline is the build margin recalculated in year 8 to represent the average of new plant additions during the first 7 years of project operation ($BM_{\underline{years\ 1\text{-}7}}$). And the same baseline calculation would be done in year 15.

$$Combined\_Margin_{2ndcreditingperiod} = BM_{years1-7}$$

$$Combined\_Margin_{3ndcreditingperiod} = BM_{years8-14}$$

This method seeks to reflect the typical displacement effects, especially, but not only, of smaller projects. In essence, by averaging both a *build* and *operating* margin across the first 7 years, the *operating* margin could be considered to apply for the first 3.5 years after the project commences, while the *build* margin kicks in at year 3.5, a reasonable lag time reflective of planning, construction, and permitting period for new power plants. Since the project will truly be affecting the capacity actually built during this period (through the delay effect), at year 8 the baseline is updated to reflect actual construction during the prior period. While this will present some uncertainty, it should be noted that investors will receive a fixed baseline for the first 7 years, and can anticipate year 8 changes by observing the evolution of the power market.[37]

2.9 Special cases: brownfield, off-grid projects and projects with specific alternatives

2.9.1 Brownfield projects

Efficiency enhancements and fuel switching at existing facilities are a potentially large source of GHG mitigation projects in the electricity sector, and an important category to consider separately given its particular features. It is useful to think of a brownfield project as <u>two</u> separate projects: one that “replaces” the electricity that would have been generated by original plant (using its original fuel), and another that increases electricity generation by making the plant more economical to operate. A brownfield retrofit or fuel switch could increase generation by increasing power plant capacity (e.g. repowering or generator replacement), by lowering operating costs (e.g. cheaper fuels, improved management, or more efficient boiler), or by extending the operating lifetime.

[37] The proposed method resembles in part the standardised methodology for small-scale renewable and efficiency projects recently adopted by the CERUPT program (Ministry of Housing, Spatial Development, and the Environment of the Netherlands, 2001, Volume 2c). The notion of a two-part operating, then build margin approach has also been considered by the Oregon Climate Trust and a PCF project in Costa Rica.

Therefore the operating characteristics of the pre-retrofit plant provides an appropriate baseline to the extent: a) that generation does not exceed pre-retrofit levels and b) that the plant is likely to continue operating as it has in the past. The second condition requires close examination. Often, plants that are good candidates for efficiency upgrades or fuel switching are those with the least attractive operating characteristics in a power system, i.e. ones using high-cost fuels or inefficient combustion equipment. There may be a significant chance that in the absence of the investment, the plant would be upgraded in a manner that affects its output and carbon intensity within the project's crediting lifetime, or on the other hand decline or cease operations entirely. Therefore, we recommend that most retrofit projects be subject to more thorough baseline analysis methods to better assess additionality (see Section 3).

To the extent that electricity production does increase as a result of the project, this added generation should be treated as other capacity addition, and use the same *combined margin* baselines described above for other projects.

2.9.2 Off-grid projects

Off-grid projects could be large in number, but due to the small amounts of electricity involved, they are unlikely to generate a significant fraction of total credits generated. For this reason, it is critical that the costs of baseline determination for this project category be kept low. Several studies have been conducted to shed light on the energy sources typically displaced by solar PV home system and other off-grid project types, as summarised by Martens et al, 2001a. Martens et al 2001b looks at baselines for various possible off-grid renewable projects. Using these studies, the Dutch CERUPT program has established a thorough set of baseline algorithms assuming displacement of kerosene, diesel generation, and diesel-based battery charging as relevant for several different project types, such as solar home systems, mini-hydro systems, wind-powered battery charging stations, and mini-grids.

Given the difficulty in obtaining detailed data to assess the particular context of off-grid projects (especially smaller ones) in great detail, this report does not provide original baseline recommendations for off-grid projects. However, reviewing the comprehensive Dutch effort (CERUPT, 2001; Martens et al. 2001b) indicates that they provide an excellent starting point for off-grid projects. The authors therefore suggest that the CERUPT baseline guidance for off-grid projects be adopted, until further studies are done to refine these figures. The CERUPT recommended emission factors for the different types of off-grid projects are presented in Annex B.

2.9.3 Projects with specific alternative

These projects are typically in category 3 (i.e. larger projects not eligible to the CDM "simplified procedures and modalities for small-scale projects) and can clearly demonstrate that a specific type of plant is the most likely alternative for the non-project case. In these cases, *minimum performance parameters* (e.g. efficiency and load factors) should be developed for the baseline calculation to ensure that the baseline scenario facilities are based on reasonable assumptions. For example, rather than calculating the baseline based on the characteristics of a very inefficient gas plant, *minimum performance parameters* could be based on an average from the most recently built gas plants (OECD/IEA 2000).

3. A decision framework for electricity projects

This section embeds the standardised baseline methods described and recommended in section 2 into a decision framework that can be applied to all electricity projects. Sections 3.1 and 3.2 describe how *additionality* and *baseline* methodologies can and should be tailored to the scale (defined in terms of investment and potential CERs generated) and environmental risk of various project types. A three-category framework is proposed, and Section 3.3 describes the specific baseline and additionality methods specific to each. In short, Category I projects would automatically qualify for the standardised baselines (combined margin for grid connected or default factors for off-grid projects), as described in Section 2. Category II projects, which present somewhat increased environmental risk, would need to pass an additionality test to qualify for this baseline. Category III projects, encompassing larger projects better able to sustain transaction costs, would require a more thorough baseline scenario analysis to evaluate additionality and determine the appropriate baseline.

3.1 Distinguishing among projects based on scale and environmental risk

No single baseline methodology can suit all the potential diversity of CDM projects in the electricity sector. These projects span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. This diversity calls for a range of baseline approaches.

In Section 2, we suggested different standardised baseline approaches for grid and off-grid applications, and new vs. retrofit projects, as well as noting some more sophisticated standardisation options (e.g. dispatch-based operating margin methods) that can be applied where data and resources allow. The natural next question is which projects should be automatically eligible to use these standardised baselines, and which should be required to undertake more thorough baseline analysis to confirm additionality. The answer to this question lies in two key factors: *environmental risk*, the potential for significant crediting in excess of actual emission reductions, and *project scale*, an indicator of a project's ability to absorb the added costs of more thorough baseline analysis. Indeed, these two factors were among the rationale for the COP in approving the CDM simplified modalities and procedures (fast-track) for small-scale projects.

As shown in Table 3-1, it is recommended that projects be placed in one of three categories of increasing sophistication, in order to balance the objectives of low transaction costs and environmental accuracy. Next, the rationale for these distinctions is described, then in subsequent sections, it is explained how these categories can be applied in practice.

Table 3-1. Recommended categories of GHG mitigation projects in the electric power sector

<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Project Scale</td></tr>
<tr><td>Too small to absorb much transaction cost</td><td>Large enough to absorb some transaction costs</td></tr>
<tr><td rowspan="2">Environmental Risk</td><td>Lower risk</td><td>Category I</td><td>Category II</td></tr>
<tr><td>Higher risk</td><td>Category II</td><td>Category III</td></tr>
</table>

A GHG mitigation project presents two related **risks to environment integrity**[38]**;** the project might have been implemented regardless of the specific GHG incentive (i.e. it is non-additional) or its baseline might be inordinately low (i.e. stringent) and therefore, no credits would accrue to a deserving project. According to Bernow et al (2001), non-additionality may present the greatest risk, especially given the inherent difficulty of assessing investor incentives and behaviour . One can identify project types that are *a priori* more likely to be additional, such as fuel cells, windfarms, or high-efficiency motor programs, because of the lack of demonstrated market presence compared with well-established technologies, such as conventional combustion turbine technologies or standard motors, or because of well-identified market constraints that limit their adoption. However, Bosi (2001) found that the risk to environmental integrity of presumed additionality for small-scale renewable projects may be acceptably small, primarily because the overall power generation share of these projects is very small. More thorough baseline and additionality methodologies can therefore be reserved for projects that present greater environmental risk, i.e. those projects employing more conventional technologies, especially at large scales. In these cases, it will be important to look more closely not only at project additionality, but also at the variety of plausible counterfactual activities or baseline scenarios.[39]

In terms of ability to cover up-front transaction costs for baseline analysis, **project scale** can be defined by the financial value of the CER revenue stream that a project is likely to earn.[40] Larger scale projects can earn a greater volume of emission credits than small-scale projects. Investors will balance the returns (CER value) against the transaction costs and risks (of non-approval) in pursuing a CDM project. Investors will tend to avoid projects whose expected CER revenues do not significantly exceed transactions costs, or present large uncertainties in terms of likely baselines (another rationale for standardisation).

Investors face transaction costs at a number of stages in the project cycle, from the preparation of project documents to monitoring and verification once the project is approved. Arguably, a detailed baseline study can be among the more significant costs, and now that an incipient market for project-based activities has developed, there is some empirical evidence upon which to estimate the costs of typical baseline studies. For projects that are not very complex, the PCF suggests that the cost of presenting a case for environmental additionality and preparing a project-specific baseline study (in accord with their fairly strict norms) is approximately US$20,000; more complex projects might double this cost to $40,000.[41] For the

[38] The environmental integrity criterion elaborated in Section 1 can be paraphrased here. The CDM is intended to displace reductions in Annex-I countries with less costly reductions in non-Annex I countries. By doing so, the CDM is intended to lower the costs of compliance with Annex I targets. Approval of non-additional projects or use of systematically high baselines, however, will generate credits that are not backed by real reductions. Parties using these credits will exceed their target, *de facto* if not *de jure*, thereby weakening the effectiveness of the CDM as a market mechanism for achieving the environmental objectives of the Kyoto Protocol.

[39] If the plausible counterfactuals span a wide range of carbon intensities, then if the wrong counterfactual were selected a project could conceivably receive a baseline emissions rate that is highly inaccurate. If the plausible counterfactuals span a narrow range of carbon intensities, the project's baseline emissions rate could not be radically incorrect even if the wrong counterfactual were ultimately selected. For example, in an electric sector dominated by one fuel, the possible counterfactuals would span a relatively narrow range of carbon intensities (corresponding to technologies with a range of efficiencies), and the environmental risk associated with selecting the wrong baseline is limited. In contrast, a CDM project in an electric sector that has several different fuels, the risk associated with the wrong baseline is greater.

[40] Another measure of project scale is the incremental investment put at risk in a CDM project, i.e. relative to the investment that would be required by an alternative (baseline) investment providing either similar services to electricity uses *or* better risk/return for the investor. The problem with this measure is that it requires estimating either the counterfactual investment or the alternative rate of return, which can add another layer of uncertainty and gaming possibilities (e.g. proving one counterfactual investment vs. another).

[41] The Prototype Carbon Fund reports $20,000 for projects that are not very complex (PCF, 2000b), based on 3-4 person-weeks for experts with an understanding of the methodology, and private correspondence with a project

purposes of discussion, let us assume a typical cost of $30,000 per detailed baseline study (see Section 3.3 for discussion of what is involved in a typical analysis). These costs can then be compared to the anticipated revenues.

Table 3-2 presents sample calculations for four illustrative projects: (a) a village-scale 100 kW hydro mini-grid, (b) a 10 MW wind farm, (c) a 200 MW hydro facility, and (d) a 200 MW natural gas combined cycle power plant. Assuming a $3/tCO$_2$ credit price (similar to current levels in the pre-CDM market), it shows the total revenue[42] that these projects would earn over their first seven years, based on some typical assumptions about capacity factor, and project emission rates, and a hypothetical baseline emission rate of 0.6 tCO$_2$/MWh[43].

Table 3-2. Baseline study costs as a fraction of 7-year CER revenues for four hypothetical CDM projects (assuming CER value of $3/tCO$_2$)

	100kW Village Hydro Mini-grid	10 MW Windfarm	200 MW Hydro	200 MW Natural Gas CC
Assumed capacity factor	50%	30%	50%	80%
Total generation (000 MWh)	3	184	6,136	9,818
Baseline emission rate (tC02/MWh)	0.6	0.6	0.6	0.6
Project emission rate (tC02/MWh)	0	0	0[44]	0.5
Credit rate (tC02/MWh)	0.6	0.6	0.6	0.1
CERs (million tC02)	0.002	0.110	3.68	0.98
CER price ($/tCO2)	$3.00	$3.00	$3.00	$3.00
Value of CERs (7 years)	$5,523	$331,355	$11,045,160	$2,945,376
Baseline study cost (at $30,000) as % of CER value	**543%**	**9%**	**0.3%**	**1.0%**

As illustrated, the costs of a $30,000 detailed baseline study would overwhelm the revenues to be gained by a 100 kW hydro mini-grid project, which stands to generate about $5,500 in years 1-7. In contrast, such baseline costs would represent 1% or less of revenues of either large (200 MW) project. The 10MW wind farm would stand to spend nearly 10% of its expected 7-year revenues. Clearly, these calculations are sensitive to assumed credit price and baseline emission rates, but the general conclusions are that:

- The cost of a project-specific baseline study could easily overwhelm the value of the revenues of a small project. In addition to providing predictability, transparency and comparability standardised baseline methodologies are essential if smaller CDM projects are to be feasible. Indeed, for a number of small renewable energy project proposals submitted for consideration, the PCF has noted that

developers and consultants suggests a figure of $40,000 for more complex projects. (These cost figures are lower than the estimated transaction costs surveyed in Bosi 2001.)

[42] These calculations are undiscounted. One would arrive at the same results (in terms of baseline cost as % of project cost) on a discounted basis, if one assumed that CER price were to increase at the rate of discount. This is not an unreasonable assumption given that some analysts project that the real CDM market could lead to prices of $5/tCO2 and above during the 2008-2012 period. (Grubb, 2001; Varilek and Marenzi, 2001)

[43] Though illustrative only, 0.6 tCO$_2$/MWh is a plausible value for many countries. For example, it is very close to the value of the build margin (i.e. weighted average of all recent plants) baseline calculated for electricity projects in India in OECD/IEA 2000.

[44] As noted above, hydro plant construction can lead to significant methane emissions from the decay of submerged vegetation, however, estimation methods have not yet been well developed.

"project-specific baseline methodologies would be prohibitively expensive" (PCF, 2000b), and the COP has embodied this rationale in its decision on simplified procedure and modalities for small-scale CDM project activities.

- The cost of a project-specific baseline study will likely be a small fraction of the value of the revenues of a large project. If a more thorough baseline analysis adds rigour (i.e. limits gaming risks) and reduces environmental risk, then more detailed baseline study would appear warranted. More detailed analysis may actually enhance investment, as may identify a more appropriate baseline that yield more credits (e.g. if a project can be convincingly shown to be displacing a higher-emitting resource).
- For projects in the range of 10 MW (for zero-carbon resources) or 15,000 tCO_2/year, baseline study costs represent a non-trivial investment. Simplified methods that reduce environmental risk while avoiding the costs of full baseline analysis, e.g. by introducing simple additionality tests, would be attractive.

3.2 Matching project types and baseline/additionality methods

Based on their relative scale and environmental risk, CDM projects can be classified into three categories of baseline methods:

- **Category I:** offers the greatest degree of standardisation and lowest transaction costs to smaller-scale projects that present the least environmental risk. Category I projects are automatically eligible for the standardised combined margin baseline recommended in Section 2. Suggested Category I projects include fast-track renewable projects and off-grid projects (that can use default baseline emission factors), because of their limited ability to support transaction costs, their less conventional nature, and thus limited environmental risk[45]. Given the lack of additionality testing, project types eligible for Category I should be considered carefully. For instance, small-scale hydropower and biomass facilities might be more appropriately considered in Category II, since they can use mature technologies and are often cost-effective under current conditions.
- **Category II:** adds an additionality test to the Category I methodology, and is appropriate for projects that present somewhat greater environmental risk due to their larger size *or* use of conventional technologies. Suggested Category II projects include fast-track energy efficiency and fossil generation projects. Though small in scale, the technologies used are likely to be fairly conventional, such as fluorescent lighting or reciprocating engines.
- **Category III:** introduces more thorough, project-specific additionality and baseline scenario analysis (see below) for larger projects that either pose more environmental risk or opt out of Category I and II approaches. This category is recommended for all project types that do not qualify for the fast track treatment.

Table 3-3 summarises the recommended classification of electricity project types (as defined in Table 1-2) into these three categories. This classification is quite general, and leaves room for further adjustment, based on the assessment of individual technologies, project designs, and/or country contexts. For instance, it would be worth examining whether larger (than fast track) advanced or unconventional technologies, which imply lower environmental risk, might be worth including in Category II. Similarly, fuel cells may be sufficiently unconventional (and higher cost) that they could be added to Category I for fast track and Category II for larger sized projects.

[45] Most, but not all, reviewers of an earlier draft of this report found this proposed trade-off (i.e. no additionality test to help fast-track small low environmental risk projects get implemented) acceptable.

Table 3-3. Classification of electricity project types by additionality and baseline method category

Category	Eligible Project Types
Category I	• Fast-track new renewable projects (FT1a) • Fast-track off-grid projects (FT1b)
Category II	• Fast-track energy efficiency projects (FT2) • Other fast-track projects (FT3) • Other projects, such as mid-size renewable or other technologies (subject to further analysis and agreement)
Category III	• All other projects, including large, new (NFT1), brownfield (NFT4), efficiency (NFT2), and cogeneration (NFT3) projects • Projects qualifying for I or II, but claiming that the standardised baseline above is inapplicable

3.2.1 Additionality tests for Category II projects

As an inexpensive means to limit environmental risk, Category II projects would be subjected to an additionality screen or test. Since the focus of this report is on baseline methodologies, specific additionality tests are not recommended, but options are reviewed.

Several additionality tests have been discussed in the literature, and included in submissions to the UNFCCC. A simple example of an additionality test is a penetration threshold. A technology would be deemed additional if it does not exceed a specified percent of electricity supply (USEPA, 2000). Low penetration can imply that a technology is not yet cost-effective in many situations, or faces difficult market or policy barriers. Penetration thresholds can be set at low levels and updated frequently to capture rapid institutional or technological advances. To simplify their application, and to reflect the fact that grid areas may be too small to capture the emergence of newly competitive technologies, penetration thresholds may be defined at a regional level instead of the grid areas recommended here for baseline development.

Another option is to define an additionality screen in terms of emissions rates. For example, an additionality threshold can be defined as a specified percentile (e.g. 10^{th}) of power plant emissions rates within a grid area, and if desired by, fuel or technology type. Projects based on technologies that exceed this threshold would be deemed additional by virtue of being more efficient (and presumably more technologically advanced) than those that typify the power sector. Like penetration thresholds, such emission rate thresholds are a fairly coarse screen, making some fraction of business-as-usual (non-additional) eligible for CERs. In this case of a 10^{th} percentile threshold, 10% of new generation sources would qualify.

Yet another option is to appeal to expert opinion and power sector surveys to define a pre-approved set of technologies that are deemed sufficiently advanced to automatically qualify as additional. This method is sometimes referred to as a technology matrix.[46]

3.2.2 Baseline scenario analysis for Category III projects

Because Category III requires a more rigorous assessment, the additionality of a project and its baseline emissions is determined through a process of scenario analysis, rather than being pre-determined as in

[46] See SAIC/USDOE (2001) for an extensive discussion and case studies based on this option.

Categories I and II. Scenario analysis is the predominant method used today for baselines.[47] It involves considering a set of plausible, alternative scenarios for what would happen in the absence of a CDM project, and then using a well-defined and reproducible process to determine the most likely baseline. The overall methodology is well described in several other sources (ERUPT, 2001; CERUPT, 2001; UNIDO, 2001; various PCF documents; Lazarus and Kartha, 2001). Therefore, this section only touches on key elements shown in Figure 3-2.

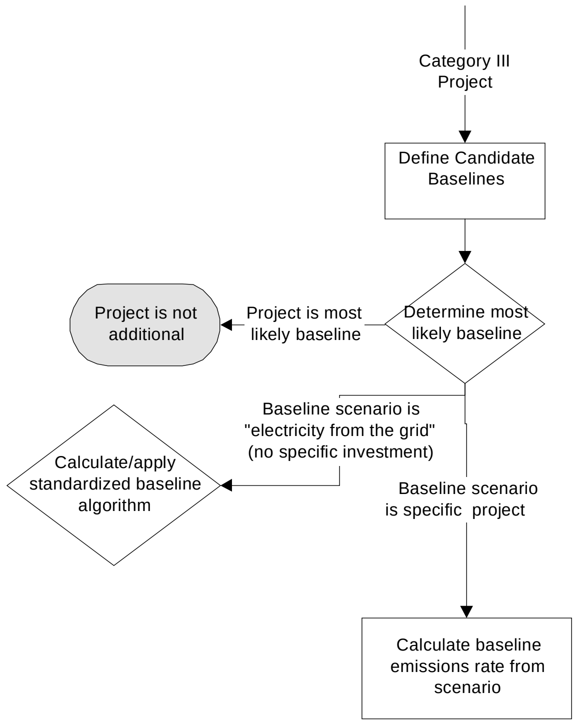
- *Define candidate baselines*: The candidate baselines identified for the scenario analysis should take into account other plausible options for meeting the same demand for electricity. Among these, the project developer should consider options such as the same project without emission credits (possibly with later implementation), and generation using other fuels and technologies that are already present in the electricity mix or likely to appear in the near future.

- *Determine most likely baseline:* A variety of approaches can be used to cull the "most likely" from the plausible baseline options. No single method – regulatory and policy analysis, barrier and risk analysis, investment/economic analysis, or a conservatism criterion – is sufficient on its own to provide a robust baseline selection methodology.[48] Instead, these methods can be used together as needed, in systematic and, to the extent possible, simplified and standardised manner.[49] Three outcomes of a scenario analysis are possible:

    1) The most likely scenario is determined to be the project itself, i.e. it would have happened anyway. The project is thus non-additional and ineligible for credits.

    2) The most likely scenario is determined to be ongoing expansion and operation of the overall electricity grid, rather than any specific investment. This outcome could also arise if several new generation options are all plausible, and there is no compelling justification to deem one option among the "most likely". In this case, it is recommended that the project adopt the same baseline emission rate (i.e. combined margin) as Category I and II projects. In such cases, the benefit of the Category III approach is a more rigorous assessment of project additionality.

Figure 3-1. Overview of Category III Methodology



[47] Arguably, this fact may be largely due to the lack of standardized baselines.

[48] See UNIDO 2001 for a comprehensive description of how these methods can be integrated.

[49] It is essential that in implementing this process that the project proponents rigourously document information, assumption, and selection processes, so that an Operational Entity can reproduce and thereby verify the project developer's choice of baseline.

3) The most likely scenario is determined to be a specific investment, facility, or activity. For example, the most likely baseline scenario for natural gas plant may be a coal plant at the same location. A specific alternative investment will most often be found for brownfield projects, such as retrofits or fuel switching, where continued operation of the existing facility provides an unambiguous facility-specific baseline scenario. In such cases, the baseline emissions rate can be quantified directly based on the presumed characteristics of the baseline investment or facility. The baseline emissions rate should be specified as a carbon intensity (tCO_2/MWh) rather than an absolute baseline (tCO_{2eq}), since the total MWh of electricity displaced (through efficiency or lower-carbon generation) will be unknown until the project is running and its output has been monitored, measured, and verified (OECD/IEA, 2000).[50] Since they may not be able to follow standardised rules, all assumptions and calculations should be presented clearly and transparently. M*inimum performance parameters* should be developed to ensure that baselines based on presumed specific fossil-based facilities use reasonable assumptions (e.g. efficiency and load factors), as discussed earlier.

[50] In certain situations, it is more accurate to express the baseline emissions rate in terms of efficiency (or heat rate, MWh/GJ of fuel). This may be the case in circumstances where the carbon intensity of the fuel supply (i.e., $kgCO_2$/GJ) can be expected to vary over time and this variation would occur in both the baseline scenario or project scenario. For example, if several coal mines with coals of different quality supply a power plant, this variation should be taken into account in determining the baseline emissions. Doing so will ensure that the project developer is neither rewarded or penalized for circumstances external to the project that affect the fuel carbon intensity. (See DOE/SAIC (2001) for a further discussion.)

4. Conclusions

No single baseline methodology can suit all the potential diversity of GHG mitigation projects in the electric power sector. These projects span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. Furthermore, a range of considerations needs to be taken into account (e.g. accuracy and rigour, transparency, cost-effectiveness, and conservatism). This diversity calls for a range of baseline approaches, as well as additionality treatment. Although the focus of this study is on baselines, some suggestions are also made for the treatment of additionality.

Based on an assessment of the scale of projects (defined by the financial value of the emission credit revenue stream), and the potential risks to environment integrity (as shown in Table 4-1), the different types of electricity projects were put into one of three categories that are then used to associate the appropriate baseline methodology and additionality treatment, where:

- **Category I:** offers the greatest degree of standardisation and lowest transaction costs to smaller-scale projects that present the least environmental risk and have limited ability to support transaction costs. Category I projects are automatically eligible for the standardised baseline and are considered to be additional by default. Since the absence of an additionality evaluation presents some risk of generating credit to business-as-usual activities, the project types placed in Category I (vs. II or III) should be reviewed periodically. It is recommended that, initially, fast track renewable and off-grid projects be considered for Category I. However, small-scale hydro and biomass projects merit further consideration (e.g. via case studies), given the mature nature of their technologies and the risk of non-additionality in some contexts (e.g. largely hydro-based power systems). In such cases, these projects might be more appropriately assessed in Category II.
- **Category II:** adds an additionality test to the Category I methodology, and is appropriate for projects that present somewhat greater environmental risk due their larger size *or* use of conventional technologies. Category II projects include of fast-track energy efficiency and fossil generation projects. Though small in scale, the technologies used are likely to be fairly conventional, such as fluorescent lighting or reciprocating engines.
- **Category III:** introduces more thorough, project-specific additionality and baseline scenario analysis (see below) for larger projects that either pose more environmental risk or opt out of Category I and II approaches. By default, this category is recommended for all project types that do not qualify for the fast track treatment (i.e. simplified procedures and modalities for small-scale CDM projects).

This paper focuses on supply-side electricity projects, although recommendations are made for calculating the emissions associated with reduced electricity demand from energy efficiency projects[51]. The paper examined various baseline methodologies. The recommendation, for most GHG mitigation electricity projects, is a ***combined margin*** approach. This approach is considered appropriate to estimate avoided generation for in most cases, as it takes into account both (i) the effect of a project on the operation of current or future power plants (this is referred to as the *operating margin*); and (ii) the effect of a project on the construction of other plants, either through delay or replacement (this is referred to as the *build margin*). It is assumed that most projects will have some effect on both the *operating* margin, especially in the short term, and on the *build* margin, especially in the longer term.

[51] Energy efficiency projects require a two-step baseline approach: (i) an energy-use baseline, and (ii) a translation of the energy use baseline into GHG emissions. Recommendations here deal with the second part of the energy efficiency projects' baseline construction.

Table 4-1. Categories of GHG mitigation projects in the electric power sector

		Project Scale	
		Too small to absorb much transaction cost	Large enough to absorb some transaction costs
Environmental Risk	Lower risk	**Category I:** - Fast-track* new renewables; - Fast-track off-grid projects	**Category II:** - Fast-track energy efficiency projects; - other projects, e.g. mid-sized renewables or other technologies (subject to further analysis and agreement
	Higher risk	**Category II:** - Other fast-track projects	**Category III:** - All projects not included in I and II, e.g. large, new, brownfield, efficiency and cogeneration projects - Projects qualifying for I or II, but claiming that the standardised baselines methodologies are inapplicable

* Fast-track refers to projects eligible to simplified modalities and procedures for small-scale CDM projects, as per the 2001 Marrakesh Accords.

The recommended baseline emission rate (measured in gCO_2/kWh) using a **combined margin** is obtained by calculating the average of the operating margin and the build margin, where:

> ***Operating Margin*****:** Effects of CDM projects on the operation of other, existing plants in a grid system, i.e. the *operating* margin, are part of the recommended combined margin (CM). Operating margin effects may predominate in the early years after CDM project implementation, before build margin effects take hold. Several operating margin methods have been suggested and applied. The most accurate operating margin methods use dispatch data or models. While useful in situations of high data and resource availability, these methods are unlikely to be widely applicable, due to data availability constraints in many cases. The simplest method, a weighted-average of all resources, suffers from the potential for large inaccuracies. Therefore, we suggest a practical method: the weighted average of all resources, excluding hydro, geothermal, wind, low-cost biomass and solar sources as they are both low running cost (i.e. defined as zero fuel cost) and must-run facilities. This should in most cases approximate the operating margin calculated using more sophisticated techniques. This should be examined further through case studies.
>
> ***Build Margin*****:** Standardised electricity baselines should embody some notion of the build margin, i.e. what plants are being built in a grid area, as recommended in the combined margin approach. Even if a CDM project may not displace new plant additions, it is likely to delay them. The recommended calculation is based on the weighted average of recent capacity additions, defined as the most recent 20% of plants built or the 5 most recent plants, whichever is greater.

Given the Marrakesh Accords' decision on the CDM crediting lifetime, an effective combined margin would consist of:

- the average of the operating margin baseline (system average minus low fuel-cost/must-run resources) and build margin baseline (based on the cohort of 20% most recently built or under construction) for the first 7 years of project crediting (or 10 years for projects electing a 10-year credit lifetime)
- the build margin baseline calculated based on new construction during the years 1-7 for the second 7-year crediting period. A similar calculation, based on new construction during years 8-15, would be done for the 3rd 7-year crediting period

This recommended baseline methodology (i.e. the combined margin) is simple, robust, comprehensive, and accounts for the diversity of projects that may arise in the electric sector. As demonstrated by the CERUPT methodology in use for small-scale projects, the data for an approach like this are readily available and the calculations are straightforward (CERUPT, 2001, volume 2c). However, for some particular types of electricity projects, the combined margin approach may not be adequate and alternative baseline treatment is recommended:

> **Brownfield projects:** For brownfield (retrofit and fuel switch) projects, the emission rate of the existing facility may be a valid baseline (subject to more rigorous analysis) up to the amount of generation that the existing facility produces. For generation beyond this amount, the standardised combined margin baseline should apply.
>
> **Off-grid projects:** It is critical that off-grid projects, such as solar home systems, hydro mini-grids, and biomass gasifiers, be provided with standardised baselines, given the small amount of emission credits (and thus little capacity to absorb baseline transaction costs) and potentially large development benefits they are likely to produce, combined with low environmental risks. Given the comprehensiveness of the Dutch efforts in this regard, it is recommended that the Dutch CERUPT standardised baseline algorithms for off-grid projects be adopted (in Annex B).
>
> **Projects with a specific alternative**: In cases where project proponents can demonstrate that only a specific plant or plant type is being displaced, such as retrofits or higher-efficiency fossil plants proposed to replace a lower-efficiency one at the same site, a fuel-specific build margin baseline may be used (i.e. a baseline based on that particular fuel) with minimum performance parameters.

Other recommendations on baseline related issues include a recommendation that the default **geographic aggregation** level for standardised electricity baselines be the country level, with host countries able to define separate sub-national grids or combine with other countries, based on actual power system management practices and transmission availability. With respect to **boundaries**, it is recommended that the boundary for power generation projects be based on direct on-site emissions (e.g. fuel combustion at the project site), given that its is both practical and conservative. Demand-side efficiency and distributed generation (and not the other electricity projects) should be credited with avoided T&D losses, using average grid area losses (excluding "non-technical losses"), or national average losses where grid-specific loss data are unavailable. Other boundary issues, such as upstream natural gas leakage, should continue to be examined, but are not included in the proposed electricity baseline recommendations at this time.

The methodology outlined above can be rendered as a step-by-step decision tree, as shown in Figure 4-1. The (green) hexagons on the left identify the main process steps.

Step 1: Determine Project Category. Projects can be placed into categories (I, II, or III) using a simple matrix. The procedure for determining a project's baseline and additionality are different for different project categories. This reflects, in large part, the distinction made in the Marrakech Accords for "small" CDM projects.

Step 2: Evaluate Project Additionality and Define Baseline. Both Category I and II projects can use the pre-defined and standardised baseline methodology (combined margin) for most projects. Category II projects need to pass a simple additionality test . Developers of category III projects need to conduct a more thorough baseline scenario analysis.

Step 3: Determine Baseline Emission Rate. The standardised baseline emission rate can be calculated by each country once a year according to the combined margin method, using the grid area, boundary, and, for energy efficiency and distributed generation projects, T&D loss methods. This baseline emission rate is then applied to Category I projects (with the exception of off-grid projects), to Category II projects that are deemed additional, and Category projects III where the baseline is determined to be the general operation and expansion of electricity grid. For Category III projects where another baseline scenario is deemed most likely, then the baseline emission rate is calculated based on the well-documented assumed characteristics of this investment, facility or activity. For instance, if for retrofit projects, the baseline is determined to be the current plant configuration, then the baseline emission rate can be determined based on current emission rates (with generation exceeding current or projected levels subject to the standardised combined margin baseline). In the case of off-grid projects, standardised default baseline emission factors (in Annex B) developed by CERUPT (2001) can be used. If a category III projects can clearly identify a specific alternative that would have happened otherwise, then a minimum performance standards may be used.

Step 4: Monitor project and update baseline. Once the baseline emission rate is established, the project can be awarded credits based on its monitored generation or savings. For CDM projects choosing the 7-year-twice renewable crediting lifetime (i.e. an option for 21 years) , the baseline will need to be reassessed (as described above) in years 8 and 15.

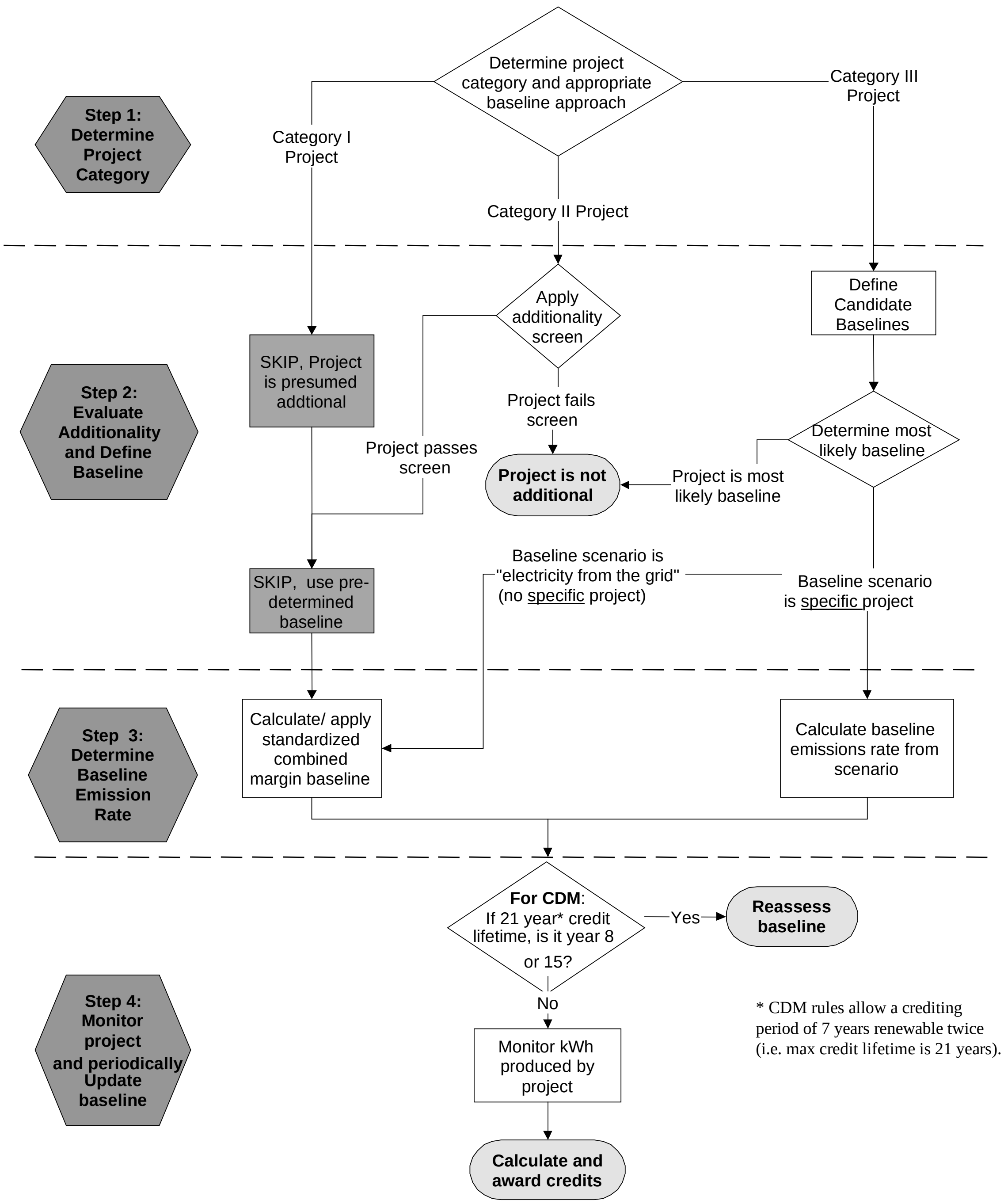
Next steps: To ensure that the recommended methodology is indeed workable in most if not all electricity contexts, several next steps should be taken, including:

- Further research and development of workable additionality testing procedures
- Review and input by host countries and other interested parties
- Road testing the recommended methodology in a number of countries using real or case study examples to (i) better assess implications and (ii) validate/modify the recommendations. For example, issues to be further considered could include:

    a) Possibilities of additional break-down of project categories (and methodologies) to account for different contexts (e.g. situations of fully-met electricity demand vs. situations of under-capacity);
    b) Application of the recommended methodology on an *ex post* basis based on actual data for the period of project performance;
    c) More detailed distinction of project types by category, in particular which require further additionality testing (Category II) or more project-specific analysis (Category III);
    d) Possibilities to refine the approach for hydro-rich countries;
    e) Enhanced accounting for upstream emissions, particularly T&D losses and methane emissions from natural gas systems.

These steps will be essential in validating the baseline recommendations and/or identifying important modifications to the methodology that might be needed. Once these revisions are incorporated, the baseline methodology and guidance could then written up in the form of short and simple to use step-by-step guidelines for host countries and project developers considering GHG mitigation projects in the electric power sector.

Figure 4-1. Overview of recommended baseline methodology



Annex A – Decision Trees by Project Category

Figure A-1. Decision Tree for Category I Projects

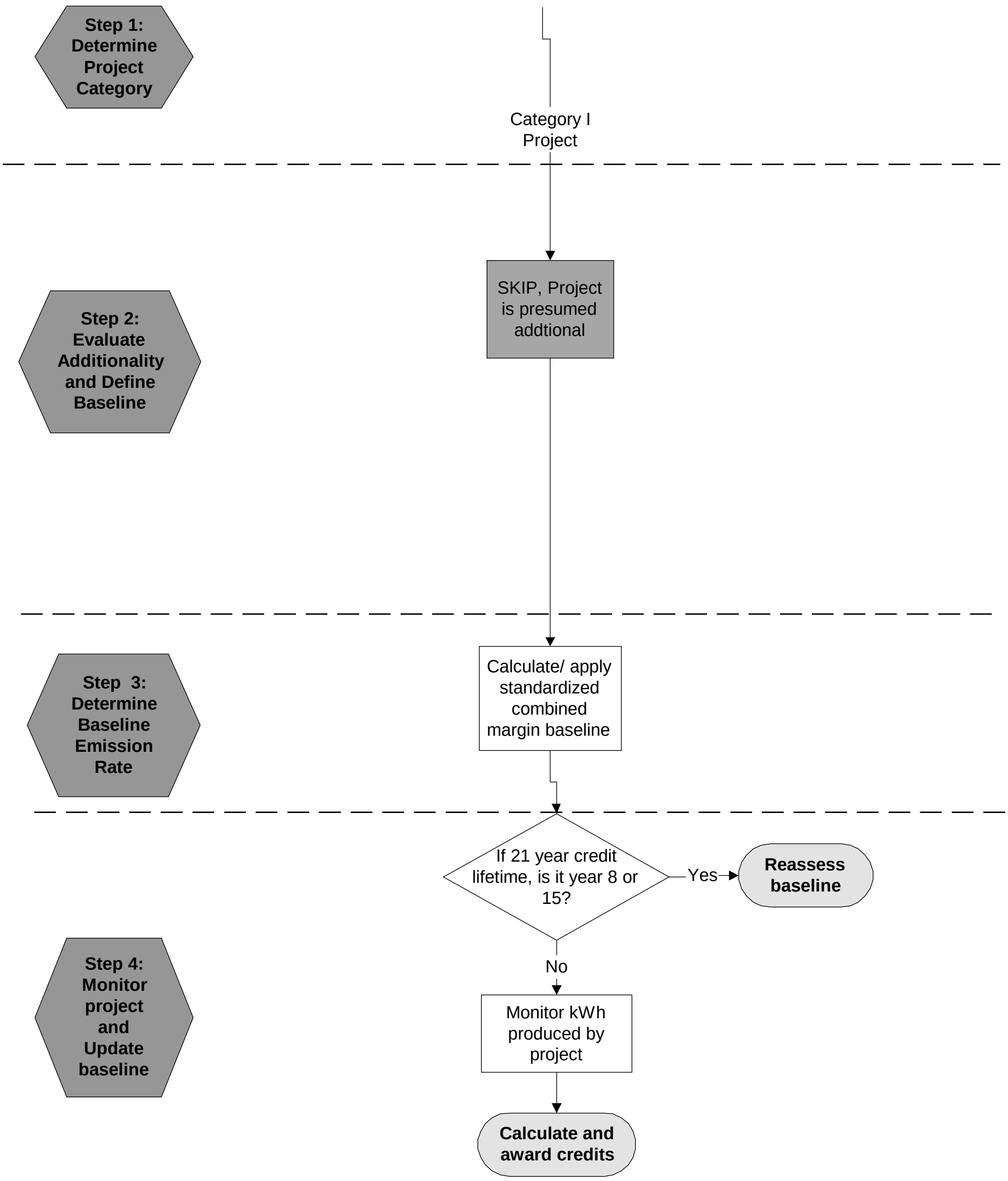


Figure A-2. Decision Tree for Category II Projects

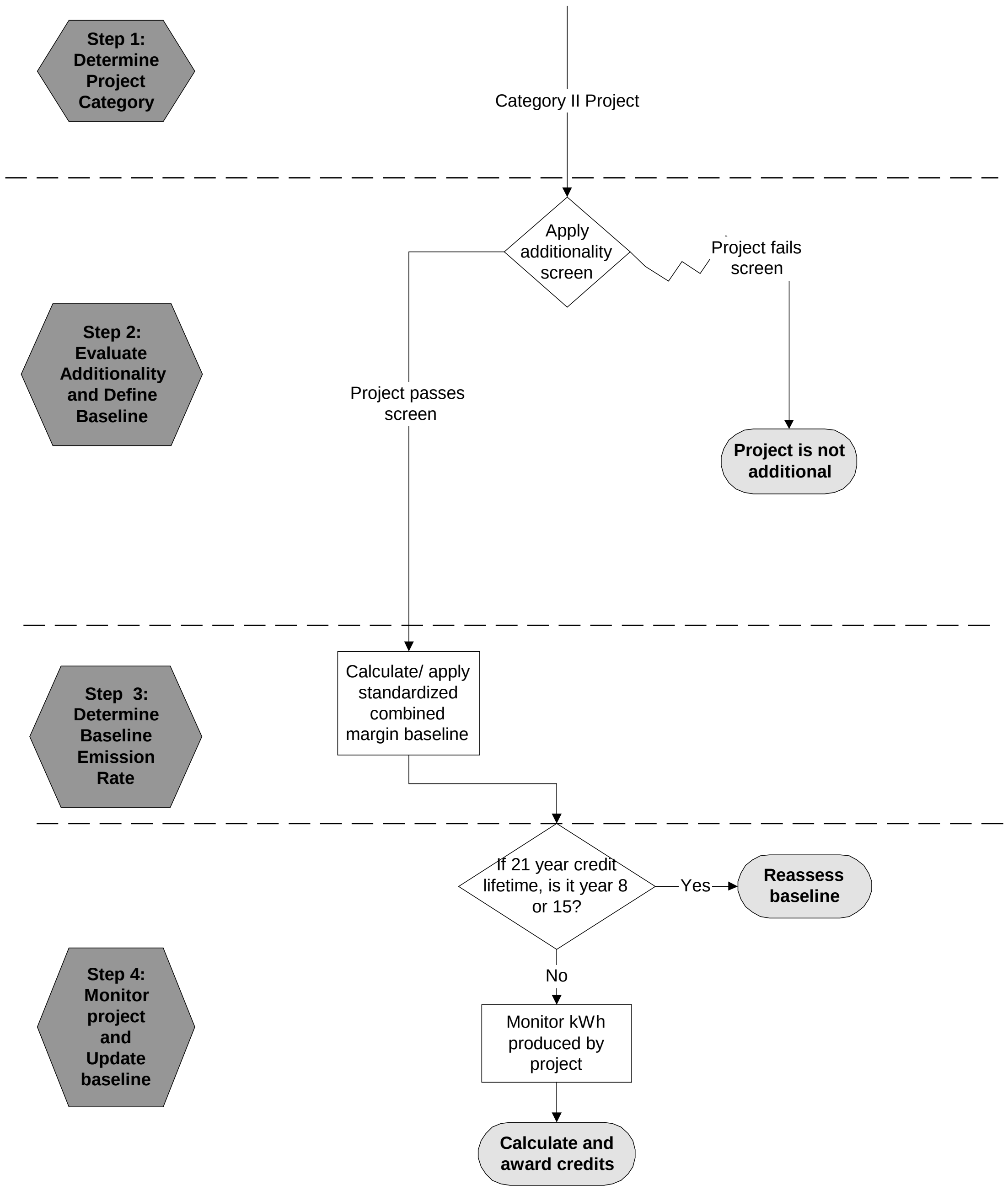
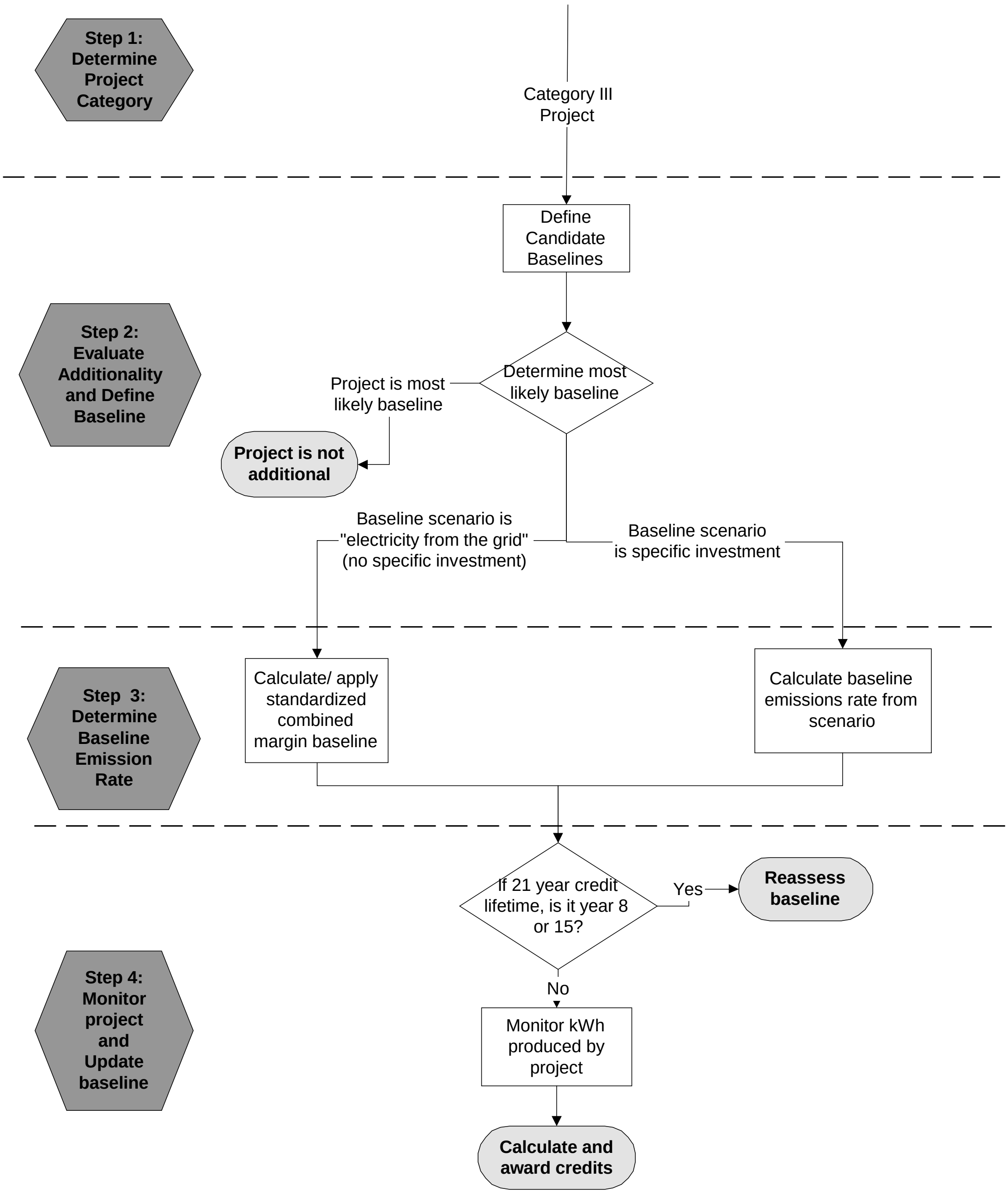


Figure A-3. Decision Tree for Category III Projects



Annex B – CERUPT Baseline Recommendations for Off-grid Renewable Electricity Projects

Given the difficulty in obtaining detailed data to assess the particular context of off-grid projects (especially smaller ones) in great detail, this report does not provide original baseline recommendations for off-grid projects. However, a comprehensive Dutch effort (CERUPT, 2001; Martens et al. 2001b) has been undertaken. Reviewing these recommendations indicates that they provide an excellent starting point for off-grid projects. The authors therefore suggest that the CERUPT baseline guidance be adopted, until further studies are done to refine these figures. These guidelines are reproduced below.

(**From the Dutch C-ERUPT guidelines**)[52]

Off-grid means not connected to a national or regional electricity grid. Instead electricity generation takes place in stand-alone applications without the need for a distribution grid, or uses a mini-grid. There is a continuum in grid sizes from extremely small (a solar home system with an extra 6 watt connection to a neighbour) to a multi-MW powered grid for a town and neighbouring areas. There are some options for defining the borderline between grid and mini-grid (based on distribution voltages (LV versus MV/HV); number of power plants (one for a mini-grid and more than one for a grid) and size of the generator. Proposed is the following practical rule: Off-grid includes all mini-grids with total generating capacity up to 15 MW, which corresponds with the small-scale CDM project definition in Decision 5/CP.6.

Categories of baselines

Diesel is the most likely benchmark for off-grid electricity provision in rural areas of developing countries. This category applies off-grid projects providing power to rural communities and to electric appliances for productive use (such as water pumps, refrigerators, power for workshops. There is one exemption: very small household technologies are more likely to replace historic household fuels, like kerosene, candles and dry cell batteries. In summary, off grid renewable projects have been divided into five categories:

a) stand-alone applications for household use
b) All renewable energy systems providing power for mini-grids;
c) mini-grid with a diesel generator and storage. The diesel generator is used to reduce required size of the storage capacity and to increase reliability and is run mainly at full load;
d) mini-grid with a diesel generator, but without storage. Application of renewables results in fuel savings. Diesel load is not constant;
e) Water pumping and productive appliances.

With hybrid systems we mean a system that uses more than one energy source. In the context of off-grid electricity project this often is a combination of one renewable energy source with diesel, such as wind-diesel hybrid, solar PV – diesel hybrid. Another possibility would be more than one energy source, for example solar-wind hybrid or a solar wind diesel hybrid.

[52] Ministry of Housing, Spatial Planning and the Environment of the Netherlands (December 2001), *Standardised Baselines and Streamlined Procedures for Selected Small-scale Clean Development Mechanism Project Activities-volume 2c: Baselines studies for small-scale project categories*, A guide for project developers, Version 1.0. The Netherlands.

B.1 Eligible project categories

Off-grid renewable electricity projects, smaller than 15 MW eq projects qualify to use the standardised baselines in this section if they use the following technologies:

i) Stand-alone household applications with daily energy consumption in the range of 50-500 Wh/d:
- Solar home systems
- Pico hydropower
- Wind battery chargers

ii) Minigrids:
- 100% renewable
- hybrid systems with storage capacity
- hybrid systems without storage capacity

iii) Productive appliances (water pumping, milling, etc.)

B.2 Standardised emission reduction factors for off-grid renewable electricity projects

B.2.1 Stand-alone household applications

This category includes stand-alone household applications with daily energy consumption in the range of 50-500 Wh/d:

- Solar home systems
- Pico hydropower
- Wind battery chargers

Because of their small size and difficult accessibility, for these projects a standardised emission reduction factor has been calculated. This is the expected baselines emissions minus the expected project emissions.

For small-scale stand alone application of renewables with daily energy consumption in the range of 50-500 Wh/d, annual CO_2 emission reduction figures are given in table B-1.

Table B-1. Global annual carbon emission reduction figures in kg CO_2 per year

Technology	**Carbon savings (kgCO_2/year)**
General: small renewables for household electrification	75 kg/y + 0.8*Energy kg/y/Wh/d (with Energy being daily load in Wh/d)
Solar Home Systems	75 kg/y + 4*Power kg/y/Wp. [kg CO_2/y]
Pico hydropower	75 kg/y + 2 kg /y /W installed capacity
Wind battery chargers	75 kg/y + 350*D^2 kg /y/ m^2 (with D = rotor diameter)

B.2.2 Minigrids with renewables and productive applications

Four different cases of minigrids require only two different baseline cases: using a load factor of 25% when the default energy service would be available for 24 hours a day, and 50% when the comparison is based on a limited service level of 4-6 hours per day (see table 1.2). With a known load factor and diesel generator capacity the resulting diesel factors are shown in table B.3.

Table B-2. Summary of the mini-grid cases

Category of mini-grid	Load factor in baselines
100% renewable	25 or 50%*)
With storage	25 or 50%*)
Without storage**	25 or 50%*)
Productive applications	50%

*) 25% for 24-hour service and 50% for limited service of 4-6 hours/day
** Please note that for hybrid systems without storage, empirical evidence shows that CO_2 emission per kWh is expected to be higher than the base case. Hence such CDM projects are not likely to qua1ify as CDM projects. The use of energy storage in the case of hybrid system is thus highly recommended if GHG savings is an objective of the project.

Table B-3. Diesel factors for diesel generator systems (in kg $C0_2$/kWh*) for three different levels of load factor**

Cases:	Mini-grid with 24 hour service	i) Mini-grid with temporary service (4-6 hr/day) ii)Productive applications iii) Water pumps	Mini-grid with storage
Load factors [%]	25%	50%	100%
3-12 kW	2.4	1.4	1.2
15-30 kW	1.9	1.3	1.1
35-100 kW	1.3	1.0	1.0
135-200 kW	0.9	0.8	0.8
> 200 kW***	0.8	0.8	0.8

*) A conversion factor of 3.2kg CO_2 per kg of diesel has been used (following IPCC guidelines)
**) Figures are derived from fuel curves in the online manual of RETScreen lnternational's PV 2000 model, downloadable from http://retscreen.gc.ca/
***) default values

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Acronyms

AAU – Assigned Amount Unit

AIJ – Activities Implemented Jointly (project-based pilot phase under the UNFCCC)

AIXG – Annex I Experts Group

CDM – Clean Development Mechanism

CER – Certified Emission Reduction (CDM credit)

CERUPT – a Dutch early CDM program (CER – Public Tender)

COP – Conference of Parties of the UNFCCC

DSM – Demand-Side Management Programs

EB - Executive Board of the CDM

ERU - Emission Reduction Unit (JI credit)

ERUPT – a Dutch early JI program ("ERU – Public Tender")

EQWG – Emissions Quantification Working Group (Alberta, Canada)

GEF - Global Environmental Facility

GERT – the Canadian Greenhouse Gas Emission Reduction Trading pilot program

GHG – Greenhouse Gas

IEA- International Energy Agency

JI – Joint Implementation

M&V – Monitoring and Verification

MOP – Meeting of Parties

NGO – Non-Governmental Organisation

PCF – Prototype Carbon Fund (a World Bank fund for pre-CDM/JI investments)

T&D - transmission and distribution

RECLAIM – Regional Clean Air Initiatives Market (an emissions trading program established in the greater Los Angeles air basin)

UNFCCC – UN Framework Convention on Climate Change

Glossary of key terms

Additionality: A project is *additional* if it would not have happened, but for the incentive provided by the credit trading program (e.g. CDM or JI). The Kyoto Protocol's specifies that only projects that provide emission reductions that are *additional* to any that would occur in the absence of the project activity shall be awarded certified emission reductions (CERs) in the case of CDM projects or emission reduction units (ERUs) in the case of JI projects. This is often referred to as "environmental additionality"

Baseline scenario: A baseline scenario is a presumed counterfactual alternative to the proposed project. In other words, it is an interpretation of "what would have happened otherwise". Several plausible baseline scenarios can be evaluated for a given project. The project itself can and should typically be considered as one of these baseline scenarios, since the possibility it would have been implemented in the absence of carbon credits (e.g. CERs or ERUs) must be examined to determine whether it is additional.

Baseline emission rate: A baseline emission rate is the parameter, expressed in tCO2/MWh for electricity projects, which is used to calculate the number of emission credits (i.e. CERs or ERUs) a project can generate. The baseline emissions rate can be based on standardised (multi-project) methodologies, or correspond directly to a project-specific baseline scenario.

Baseline scenario analysis: This commonly-used baseline methodology involves a process of elaborating, then culling through, a series of plausible baseline scenarios, often involving investment or barrier analysis. This analysis is useful to demonstrate the *additionality* of a project.

Build margin: The build margin refers to new sources of electric capacity expected to be built or otherwise added to the system, and affected by a new project-based activity.

Combined margin baselines: A combined margin baseline reflects both operating and build margin effects.

Direct emissions: Direct emissions are a direct consequence of project activity, either on-site (e.g. via fuel combustion at the project site) or off-site (e.g. from grid electricity or district heat, and other upstream and downstream life cycle impacts).

Distributed generation: This term is used for a generating plant serving a customer on-site, or providing support to a distribution network, and connected to the grid at distribution level voltages. The technologies generally include engines, small (including micro) turbines, fuel cells, and photovoltaics.

Indirect emissions: Indirect emissions occur when market and individual response to a project activity leads to increased or decreased emissions. Indirect emissions can be either on-site (e.g. rebound effects such as increased heating that may result from of an insulation program) or off-site (e.g.* project effects that are often referred to as leakage, either negative or positive, such as economy-wide response to price changes or increased penetration of low carbon technologies outside the project site induced by the project activity.)

Investment additionality: Investment additionality seeks to compare the financial return of a project and its alternative (baseline scenario) to determine additionality of a CDM or JI project and/or the most likely baseline.

Operating margin: The operating margin refers to the changes in the operation of plants in an existing power system in response to a project-based activity (e.g. CDM).

Standardised baseline emission rate: A standardised (or multi-project) baseline emission rate can be calculated without reference to an individual project, based on a pre-defined methodology and characteristics of the regional power system.