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ROAD-TESTING BASELINES FOR GREENHOUSE GAS MITIGATION PROJECTS IN THE ELECTRIC POWER SECTOR

INFORMATION PAPER

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FOREWORD

This document was prepared by the IEA Secretariat in October 2002 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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Questions and comments should be sent to:

Ms. Martina Bosi
Administrator, Energy and Environment Division
International Energy Agency
9, rue de la Fédération
75015 Paris, FRANCE
Email: martina.bosi@iea.org
Fax: +33.1.40.57.67.22

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Executive Summary

Emission baselines are crucial for determining the emission reductions resulting from a greenhouse gas (GHG) mitigation project and calculating the associated emission credits. They are required for the implementation of the Kyoto Protocol's project-based mechanisms, i.e. the Clean Development Mechanism (CDM) and Joint Implementation (JI), as well as any project-based trading programme to reduce GHG emissions.

Baseline standardisation, by providing consistency and transparency, can contribute to ensuring the environmental integrity of project-based mechanisms, while also helping limit their transaction costs. Kartha et al. (2002) developed workable baseline methodology recommendations for grid-connected electricity projects that could contribute to eventual "default" baseline methodologies for GHG-mitigation projects undertaken in the electricity sector (e.g. similar to the IPCC Guidelines for National Greenhouse Gas Inventories). While the Kartha et al. (2002) analysis and recommendations focussed on the Kyoto Protocol's CDM, they may apply equally well for electricity projects implemented in other contexts.

Kartha et al. (2002) recommended a "combined margin" methodology for grid-connected electricity generating projects. Such a methodology reflects a project's typical effect on GHG emissions of (i) the operation of current or future power plants (referred to as the *operating margin*) and (ii) what and/or when new facilities will be built (referred to as the *build margin*). This paper tests the *combined margin* methodology for Brazil, Chile and South Africa, outlining all the steps involved in the implementation of the baseline recommendations, to provide as much transparency as possible to facilitate observers' assessment of the methodology and its implications.

Detailed plant-specific data is needed to calculate a *combined margin* emission baseline. These data were gathered by in-country experts, which enabled an efficient identification and collection of relevant data sources and other information within each country.

Data availability and accessibility differed between the three countries. Chile had the most comprehensive and readily available grid-connected plant-level data (for plants in operation). Calculating operating and build margin baselines for Brazil and South Africa was also possible, but additional information and assumptions were needed to complete data collected by the country experts. Data gaps included start-of-operation dates, load factors and efficiencies, unit-level (as opposed to plant-level) data, and data on plants under construction. Based on the plant-level data, the authors then calculated *build margin* and *operating margin* for all tested countries, including for both grids for Chile and Brazil, as well as a *combined margin* emission rate for each electricity system.

Taking local circumstances into account - through the use of local generation data to derive a grid-specific *combined margin* emission rate - leads to different baseline levels and, consequently, different quantities of emission credits being earned by similar projects implemented in different electricity grids. Such an outcome is to be expected if credits are to be awarded for emission reductions from displaced electricity in countries that have significantly different situations, because "what would happen otherwise" is also significantly different. For example, low GHG-emitting CDM electricity projects implemented in countries that have very high GHG-emitting power sectors, such as South Africa, will lead to greater reductions in global emissions compared to other countries with a less GHG-intensive power sector. However, such an outcome could be considered as disadvantaging those countries that opted, earlier, for less-GHG emitting sources of generation.

This paper compares the possible emission reductions from a hydro plant and a natural gas plant in combined cycle under the different electricity systems' *combined margin* baselines. A larger volume of credits will certainly help attract investors interested in CDM projects, although other factors are also taken

into account in any investment decisions. An assessment is made of the possible economic contributions of emission credits in offsetting the costs of different types of electricity project – often by a relatively small percentage, especially at low credit price levels. It is not possible to predict, however, based on this analysis, the volume of projects that would be undertaken under the tested baselines.

While the road-testing suggests that the costs associated with collecting the plant-level data and calculating the recommended *combined margin* emission baselines are manageable, one cannot necessarily generalise this road-testing experience to all countries. Public authorities' efforts to ensure that the necessary plant-level data is collected and is as easily accessible as possible, or, at least, that relevant data sources for each power system are clearly identified for use by project developers, would be helpful and would contribute to limiting the costs of *combined margin* baselines. This could be particularly important for the feasibility of small-scale GHG-reducing projects. Economies of scale could be made if, once collected, the full data-set used to develop the baselines were made publicly available and thus useable (in a consistent manner) for other potential projects developed in the same geographic area in a similar timeframe.

This paper recommends that in order to be most cost-efficient, the *combined margin* baseline emission rate be developed at the start of the project-based activity, and only updated periodically (e.g. if the baseline were to be renewed).

Developing emission baselines is, in some ways, like estimating the unknown. No single baseline, or baseline methodology, can be considered "perfect", given the inherent uncertainty of establishing an emission level corresponding to what would otherwise happen. Nevertheless, the *combined margin* baseline methodology for grid-connected electricity projects seems to have the potential to strike an appropriate balance between the need for environmental integrity, workable, predictable and transparent methodologies and low transaction costs. The methodology is technically simple to apply and does not involve making subjective assumptions, for example on the single most likely alternative to a CDM-type project, that could significantly alter the level of resulting emission baselines.

Through the road-testing, this paper also provides some insights on baseline guidance for two particular situations: (i) hydro-rich systems; and (ii) coal-dominated systems with little recent capacity additions. This analysis suggests that the baseline recommendations should be refined to be more relevant in these (extreme) circumstances.

Kartha et al. recommended a modification to the *operating margin* calculation in hydro-rich countries: excluding a fixed percentage of hydropower generation, e.g. 50% of total generation (instead of excluding all must-run and zero fuel costs generation, as in other cases). However, specific *ex-ante* guidance is needed to clarify in which circumstances exactly this modified *operating margin* calculation should be undertaken (e.g. systems where a given high share of the total generation comes from hydropower). Alternative approaches, such as a "sliding scale" where the quantity of hydropower excluded from the calculation varies according to the hydro-intensity of a system's power mix, also merit further consideration. In the case of systems dominated by fossil fuel power plants (such as South Africa), the fact that coal plants are must-run facilities (and not hydropower and other renewables,) should be reflected in the *operating margin* calculation. Further examination of this type of situation and possible ways to develop a more appropriate *operating margin* might be warranted.

Moreover, in the interest of developing some default baseline calculation methodologies that could be applicable to different circumstances, it would also be useful to further examine the question of baselines in the context of countries with too little recent capacity additions to develop a meaningful *build margin* emission rate. Feedback from experts in those countries would help such a discussion and perhaps enable reaching some consensus on most suitable and appropriate approach(es).

Developing guidelines for making assumptions (possibly different in different circumstances) when data is missing would help ensure consistency in the development of baselines.

Determining whether the *combined margin* baseline outcomes are "reasonable" in every case – or "better" than other approaches - is a matter of judgement, and feedback from a wider stakeholder community would be useful. Notwithstanding these caveats, the *combined margin* baseline methodology does seem worthy of further consideration by policy-makers involved in setting baseline rules for project-based mechanisms and/or credit based systems, such as the CDM Executive Board. The *combined baseline* methodology is not a "perfect" solution to estimating the unknown. But it could be a potential "default" baseline approach for project developers investing in GHG-reducing grid-connected electricity projects. It could also be a particularly useful reference for those involved in the validation and certification of emission reductions.

1. Introduction

Just as new car prototypes need to be "road-tested" to see how they perform in real-life conditions, new ideas and concepts also need this type of testing. Car prototypes that do not pass the road-test will not be produced for commercial sale; similarly, new ideas or concepts that cannot demonstrate that they are workable in real-life conditions will not be implemented. This paper seeks to test baseline recommendations for greenhouse gas mitigation projects in the electric power sector.

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 crucial for determining the emission reductions resulting from a GHG mitigation project and calculating the associated emission credits. They are required for the implementation of the Kyoto Protocol's project-based mechanisms, i.e. the Clean Development Mechanism (CDM) and Joint Implementation (JI), as well as any project-based trading program to reduce GHG emissions.

However, the reality is that no single baseline, or baseline methodology, can be considered "perfect", given the inherent uncertainty of establishing an emission level corresponding to what would otherwise happen. How can one verify what doesn't happen? The assessment of a particular baseline or baseline methodology is thus probably best described by asking "is the baseline (or baseline methodology) *reasonable*?", as the nearest approximation to "is it *right?*". Transparency, consistency and predictability are all important features of a baseline methodology.

Baseline standardisation, by providing consistency and transparency, can contribute to ensuring the environmental integrity of project-based mechanisms, while also helping limit their transaction costs[1]. This is what Kartha et al (2002) sought to do by recommending "workable methodologies" for calculating emission baselines for GHG mitigation projects in the electric power sector. Their aim was to make a contribution towards the development of CDM baseline guidelines that could ultimately resemble the straightforward IPCC Guidelines for National Greenhouse Gas Inventories. The Kartha et al. (2002) baseline recommendations should thus be considered as recommendations for possible "default" baseline methodologies for electricity projects that are sufficiently clear and simple to be applicable by institutions in most countries. (As is the case with the IPCC Guidelines, the recommended baseline approach would still allow project developers to opt for more detailed and thorough baseline methodologies, where desired and justified.)

The authors of this paper seek to "road-test" these baseline methodology recommendations for grid-connected electricity generation projects, relying on the collaboration with local experts in three developing countries: Brazil, Chile and South Africa.

This study addresses the following questions: Are the necessary data available and easily accessible? What are the key data sources within each country? What kinds of assumptions need to be made? Are the resulting baseline emission rates reasonable? How do the different countries compare? What could be the economic implications for potential investors? Based on the road-testing, conclusions are drawn on the validity and applicability of the baseline recommendations.

[1] Baseline development costs are often described as a significant portion of total project-based mechanisms-related transaction costs.

The authors have sought to make this baseline road-testing as transparent as possible. It is hoped that the conclusions from this work contribute both to the informed and successful implementation of project-based mechanisms that provide environmentally sound outcome, and lead to incentives to attract greater GHG-friendly investments in the power sector.

1.1 Approach

One of the important features of this work is its reliance on actual in-country data, in contrast to previous OECD/IEA papers and work on emission baselines in the electricity sector which relied on a commercial database (i.e. Utility Data Institute (UDI)/McGraw-Hill, *World Electric Power Plants Data Base*). Indeed, this facet of the work is critical, as it allows for an assessment of the data availability and data gathering possibilities within different host countries.

Three developing countries were chosen to test the baseline recommendations for GHG mitigation projects in the electric power sector (drawn from Kartha et al. 2002) with actual in-country data: Brazil, Chile and South Africa. These countries were chosen because of the different characteristics of their power sectors (i.e. a hydro dominated sector in Brazil, a coal-dominated sector in South Africa, and a mixed generation sector in Chile), thus allowing an examination of the implications of the baseline recommendations in different circumstances. As project-based activities, especially in the context of the Kyoto Protocol's CDM, are often aimed at harnessing private sector investments in climate-friendly projects, it was deemed important to start testing with countries that seemed attractive for potential investors. The three countries selected ranked among the top-10 countries most attractive for CDM investments (PointCarbon 2002)[2]

Furthermore, given the interest in learning about the particular baseline data collection processes within each country, combined with the short timeframe for the project, the selection of the three countries was also based on the availability of local experts to assist in the data collection. However, these three countries may not be representative of other developing countries, particularly in terms of data availability.

Prof. Pedro Maldonado (Universidad de Chile, Chile), Prof. Roberto Schaeffer (Federal University of Rio de Janeiro, Brazil) and Mr. Harald Winkler (University of Cape Town, South Africa) were responsible for the data collection – by power plant – within their respective countries.

An Excel template was developed to ensure that consistent information on individual power plants was gathered in all three countries. The following information and data was sought for each power plant:

- the name of the plant/unit;
- the location of the plant;
- the status of the plant (operating, retired, or in construction);
- whether the plant was on-grid or off-grid;
- the name of the grid;
- the date in which production began;
- the plant/unit's capacity (in megawatts);
- the fuel type (e.g. type of coal);
- the technology used;
- the load/capacity factor, i.e. the portion of total possible hours in a year during which the plant/unit is in operation;
- the fossil fuel conversion efficiency.

[2] See The Carbon Market Analyst, News Alert 07 June 2002, *CDM Investments: Where and How?*, where Brazil ranks second, South Africa ranks third, and Chile ranks seventh in the list of most attractive countries in which to undertake CDM projects.

The local experts were also asked to briefly explain their data gathering process, their data sources, whether some data was unavailable, and why. In cases where no actual data was available, experts provided assumptions to generate replacement data. The missing data and the assumptions made to generate these data for each country are listed in section 3.

After compiling and reviewing the data, the greenhouse gas emission calculations (t CO_2 per GWh of power generated[3]) for each plant were completed at the International Energy Agency (IEA) using IPCC default emission factors[4]. The principal authors of this report then calculated, in a consistent manner, for each electricity grid of the countries examined, the emission rates corresponding to the "build margin", "operating margin", and "combined margin", as per the baseline recommendations in Kartha et al. (2002) (see next section for a description of the different "margin" calculations).

The analysis considers each case study country individually and also compares baselines implemented in the different electricity contexts. The paper also considers the possible economic implications for different potential GHG mitigation projects and the value of emission credits under different circumstances. Implications of this analysis for the initial baseline recommendations are then assessed.

[3] 1 t CO_2/GWh = 0.001 kg CO_2/kWh.

[4] Using country-specific emission factors could lead to slightly different results.

2. Baseline Recommendations[5]

Baselines are intended 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. 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 (i.e. selecting advantageous baselines), and reduce transaction costs. By providing consistency and transparency, baseline standardisation can indeed contribute to ensuring the environmental integrity of project-based mechanisms. This is what Kartha et al (2002) sought to do by developing workable baseline methodology recommendations that could contribute to eventual "default" baseline methodologies for GHG-mitigation projects undertaken in the electricity sector.

Several studies have identified the electric power sector as particularly suitable for the development of standardised baselines (e.g. Bosi (2000), Lazarus et al (1999), UNEP/OECD/IEA (2001), etc.) as well as for GHG reduction opportunities. However, standardisation for electricity baselines should take regional, national or sub-national circumstances into account. In other words, a single emission baseline (x kg CO_2/kWh) to assess all electricity projects regardless of their location would not credibly reflect the "what would happen otherwise" case, at least for grid-connected electricity projects. Taking national and regional circumstances into account, Kartha et al. (2002) developed recommendations for baseline calculation methodologies that provide a consistent and predictable approach to calculating emission baselines, using "local" data, which result in country-specific or grid-specific emission baselines.

Establishing the baseline for a GHG-reducing electricity project requires determining how that project's generation affects the operation or construction of other plants on an interconnected grid, or what would have happened in the absence of the project. Kartha et al. (2002) note that the debate surrounding electricity baselines centres on whether or not the generation that would happen otherwise can be determined by the "build margin" (i.e. assuming "avoided generation sources" replace the *building* of a new source of electricity) and/or the "operating margin" (i.e. assuming that "avoided generation sources" affect the *operation* of current and/or future power plants).

Kartha et al. (2002) examine different possible approaches for calculating baseline emission rates. The authors used a series of criteria to evaluate the different baseline approaches, such as accuracy, data availability (practicality), transparency, conservatism, cost-effectiveness, etc. "Practicality" was considered a key criterion, as data availability is essential for developing implementable and practical baseline recommendations. This reinforces the relevance of one of this study's main objectives: to verify the practicality of the baseline recommendations, in terms of the availability of the necessary data.

A "combined margin" approach for most grid-connected projects where the counterfactual scenario is assumed to be the ongoing expansion and operation of the overall electricity grid- rather than one specific power plant investment- is recommended by Kartha et al. The recommended *combined margin* baseline calculation (resulting in an emission rate: t CO_2/GWh), as presented in Box 1, is a combination of a new project's effect on (i) the operation of current or future power plants (referred to as the "operating margin"), and (ii) on what and/or when new facilities will be built (referred to as the "build margin"):

- The *operating margin* approach is based on the assumption that a project's principal effect is to modify the operation of existing power plants. Typically, this requires information to identify the last plants to be "fired up" to meet demand at any given time. This information can include historical dispatch data (i.e. which plants were operated during which hours), the hourly cost of different plants (or their bid

[5] This section draws heavily from sections 2.6, 2.7, and 2.8 of Kartha et al. (2002).

prices in competitive environments), or stacked-resource load curves that assemble the plant generation data in merit order. However, in many countries, this type of information is difficult to obtain, as it is considered confidential, especially in privatised power systems. As indicated in Table 1, Kartha et al. recommend a proxy for estimating the *operating margin* of power system, relying on generally available and easily accessible data.

- The *build margin* approach seeks to make a "best guess" on the type of power generation facility that would have otherwise been built (or built sooner), in the absence of the GHG mitigation project. As noted by Kartha et al., even in well-planned electricity systems, it is not easy to determine the timing and type of new electricity capacity additions. The challenge is magnified in electricity systems having gone through privatisation processes. Expansion plans and projections are thus subject to major uncertainties, and often lack transparency. To reduce gaming possibilities (i.e. choosing an overly GHG-intensive projection) and to increase the likelihood of availability and accessibility of the necessary baseline data, Kartha et al. recommend using data on historical capacity additions that are most recent and capacity under construction. Unless it can be clearly demonstrated that a project would displace another specific power plant, then standardised build margin emission rates that are drawn from a mix of likely capacity additions, as per the Kartha et al. (2002) recommendations, are preferable to "plant specific" baselines.

Box 1: Calculating the *combined margin* baseline emission rate

➪ Since most grid-connected electricity projects are likely to affect both the operation of current or future plants, i.e. the *operating margin* (in the short run), as well as the building of new facilities, i.e. the *build margin* (in the long run), electricity baselines should reflect a combination of these effects. Kartha et al. (2002) thus recommend using the *combined margin* (CM) as a possible default baseline methodology; it is an average of the operating margin and build margin emission rates (in t CO_2/GWh):

$$Combined\_Margin = \frac{OM_{year1} + BM_{historical}}{2}$$

- *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, the build margin baseline should generally reflect all power plant types being added to the system. This method involves collecting data on the most recent and ongoing power plant construction activity. It is recommended that the BM baseline emission rate be calculated using the generation-weighted average emissions rate of the most recent 20% of plants built within a country/grid, including those currently under construction, or the most recent 5 plants, whichever is greater. (Calculating the build margin emission rate from the most recent 5 plants might be more appropriate in the case of power systems where there have been very few plants constructed in recent years.)
- *Operating Margin (OM): Operating margin* effects may predominate in the early years after the CDM project implementation, before *build margin* effects take hold. *While* several more or less complex operating margin methods have been suggested and applied, Kartha et al. suggest a practical method[6] based on the weighted average of all plants in operation, *excluding* facilities that are both must-run and that have zero fuel-costs[7]: hydro, geothermal, wind, low-cost biomass[8], and solar. The rationale behind this recommendation[9] is that it is unlikely, in most systems, that plants without associated fuel costs would operate less in response to new generation from a CDM project[10]. However, the authors note that one exception would be systems where hydropower comprises a majority of the resource mix. In such situations, excluding all hydropower generation might overestimate the operating margin calculation. One suggested option to deal with such circumstances is to exclude a fixed percentage of these resources (e.g. 50% of total generation) from the *operating margin* calculation, in order to reflect that some share of the renewable energy generation follows the load. (This option is used in this analysis for calculating the *operating margin* in Brazil.).

[6] Referred to as "OM2" in Kartha et al. (2002).

[7] Kartha et al. note that the recommended OM calculation should, in most cases, approximate the operating margin calculated using more sophisticated techniques.

[8] Examples of low-cost biomass resources are bagasse residues burned at sugar refineries, or paper and pulp residues burned. Examples of higher cost biomass resources would include dedicated crops, such as woody feedstocks, or residues that require costly transportation to power plant sites.

[9] More detailed dispatch data or models could also be used if they allow a more sophisticated approach to calculating the *operating margin*.

[10] Hydropower plants and other renewables plants are usually dispatched in preference to thermal plants because of their lower variable costs. Nonetheless, Kartha et al. 2002 mention that the issue of which resources to exclude likely deserves closer examination.

This report focuses on road-testing the proposed "combined margin" baseline for grid-connected electricity generation projects. However, it is useful to recall that Kartha et al. (2002) identified some particular electricity projects where this approach is not considered most appropriate. For example:

- A brownfield project (retrofit and fuel switch): it was recommended in the Kartha, et al (2002) report that the emissions rate of the existing facility may be a valid baseline up to the amount of generation that the existing facility produces. The combined margin baseline methodology should be applied to projects whose power generation goes beyond this amount.

- Off-grid projects: Because these operate in particular circumstances and are typically smaller than grid based power plants, it is critical that a clear, simplified baseline be established in order to keep transaction costs low. Kartha et al. (2002) propose that the Dutch CERUPT baseline guidance recommendations be adopted in the case of off- grid projects, until further studies are done to refine the recommended figures.

Annex I includes a step-by-step description of the emission baseline calculation process (based on each plant's CO_2 and CH_4 emission). Annex II presents an overview of the Kartha et al. recommended baseline methodology, along with suggested additionality methods, for different electricity projects. In fact, Kartha et al. (2002) classify projects into three categories, according to projects' relative scale (in terms of investment and potential emission credits generated) and environmental risk (i.e. the potential for significant crediting in excess of actual emission reductions). The proposed three-category framework associates specific baseline methodologies and additionality treatment[11] to each category, with more thorough additionality analysis for larger projects that either pose greater environmental risk or opt out of the other two category approaches (Annex II illustrates this framework).

[11] The focus of the Kartha et al. (2002) report is on baseline methodologies. A framework including the assessment of additionality is proposed. However, specific additionality tests are not recommended; rather, a series of additionality options are reviewed.

3. Road-Testing: Putting the recommendations into practice

This section seeks to implement the baseline recommendations in the context of three countries with power sectors with different characteristics. For each country, the power sector is described, as well as the data-gathering process and key information on the country's power plants. This information is intended to enable a better assessment of the baseline calculations, with results presented in tables in sections 3.1, 3.2 and 3.3.

Baseline calculations include both carbon dioxide CO_2 emissions (calculated based on the type of fuel used by each plant) and methane (CH_4) emissions[12] (calculated based on the type of technology of each plant) associated with the production of electricity, which can be easily estimated using IPCC default emission factors.

3.1 Brazil

Brazil has the ninth largest economy in the world. Its population of 172 million inhabitants and Gross Domestic Product (GDP) of USD 900 billion (measured in Purchasing Power Parity terms) represents one-third of the Latin American totals. Brazil is also Latin America's largest energy consumer, with oil and hydroelectricity dominating its energy sector.

Brazil is highly urbanised with approximately 80 percent of the population living in urban areas. But as of 1999, some 2.2 million households (about 5 percent of all households in Brazil) still did not have electricity services, with some low-income households in rural areas relying on wood as a major energy source. Some 93 percent of the population that have electricity services are connected to a grid, with some 7 percent relying on isolated systems, mainly in Northern region of the country.

According to the data gathered by the Brazilian experts, total electricity generation in Brazil from all grid-connected plants in operation amounted to 351 TWh[13] in 2000. Another 213.6 TWh per year is expected from plants currently under construction (see Box 2). Data was also obtained on off-grid plants, which currently generate 18.1 TWh annually (another 3 TWh are under construction).

In 2000, 47 percent of total primary energy supply (TPES) came from oil and 15 percent from hydroelectricity. In fact, hydroelectricity drove 85 percent of Brazil's 73 GW of installed grid-connected power-generation capacity.

The new regulatory framework and international gas pipelines interconnecting Bolivia and Brazil is facilitating the penetration of gas in the power sector (its current share in TPES of some 5% is projected to increase to 13% in 2020). Market reforms, together with Brazil's remaining vast hydro potential[14], along with the gas pipelines already built or planned, and the rising demand for electricity, are expected to make Brazil's power sector increasingly attractive for private investment. Brazil has already had some success,

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[12] Emissions of CH_4 associated with fuel combustion for the generation of electricity are very small, representing less than 1% of CO_2 emissions. Emissions of N_2O (small) are not estimated, as default emission factors are only available for few types of technologies.

[13] This is fairly consistent with IEA statistics: 349 TWh in 2000 (IEA 2002).

[14] Brazil's additional hydro potential, measured in terms of firm energy (i.e. the maximum power that can be generated during the worst hydrological period) is estimated at 143 GW, representing about 2.5 times the country's current hydropower capacity (IEA 2002 forthcoming).

with a few electricity-generation companies, and most of the distribution companies having been privatised. Currently, private investors own one-fourth of Brazil's power generation and two-thirds of distribution.

The privatisation process was possible due to key power sector legislation. In 1993, Law 8631 required tariffs to reflect costs and permitted utilities to retain profits from efficiency gains. In 1995, Law 9074 provided a legal basis for Independent Power Producers, and the electricity grid was opened to them. In 1996, consumers of more than 10 MW were allowed to buy electricity from any utility. Public bidding was mandated in the selection of utilities and open access to the transmission grid was guaranteed. Finally, in December 1996 Law 9427 established a new power regulatory agency, Agência Nacional de Energia Elétrica (ANEEL). ANEEL started its activities in December 1997.

However, this process also led to some mixed results. In late May 2001, Brazil faced nation-wide power rationing in order to save valuable water in the severely depleted reservoirs and to avert major blackouts before the end of the next rainy season (November-May). The electricity crisis highlighted the lack of investments in the expansion of the Brazil's power sector during the 1990s, forcing the country to operate its hydropower reservoirs on an annual rather than pluriannual basis. A rationing plan (affecting the residential sector, as well as commercial and industrial sectors) lasted for ten months, from June 1, 2001 through February 28, 2002. As a consequence, the public began to question the effectiveness of the privatisation process in Brazil, which may have repercussions on the future development of the country's power sector. Moreover, 2002 has been a year with plenty of rain, to the point where there is now excess water in the hydroelectric reservoirs. This, combined with a slowing down of the economy and the associated lower electricity consumption are resulting in uncertainties that are already having an effect on planning, with some natural gas plants orders being cancelled (see Box 2).

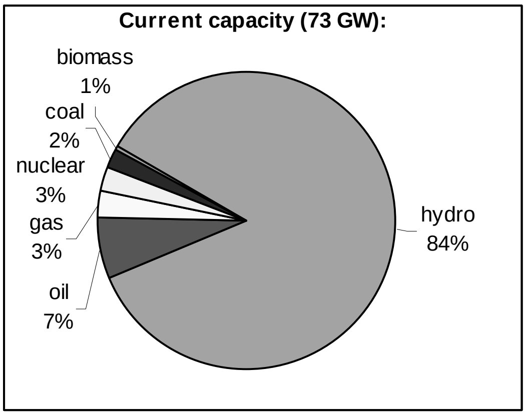
Box 2: The Evolution of the Brazilian Power Sector?

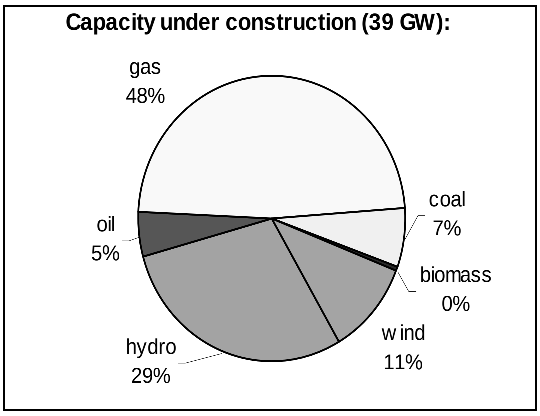
➪ For several years, the Brazilian government has been indicating the need to increase thermal capacity (mainly gas-fired) in order to reduce the country's reliance on hydroelectricity, while helping meet the country's increasing demand. Its 1995 power sector reform programme was supposed to lead to significant new power generation capacity financed by private investors. Brazil's predominant reliance on hydro could thus be expected to slowly decrease (although remaining the main source of power), as the competitiveness of new hydro is reduced due to relatively high transmission and construction costs for remaining sites. In addition, around half of Brazil's remaining hydro potential is located in the Amazon area, which may not be considered appropriate for reservoir development. The building of gas infrastructure is leading to greater natural gas use in the country's electricity mix.

However, several factors make it difficult to predict exactly what kind of investments will be made in Brazil's power sector[15]. The uncertainties surrounding the future of the power sector reforms in Brazil, combined with the current slower economic growth make potential investors cautious. Also important is the fact that investments in gas-fired power generation are subject to currency risks, as investments and gas are paid in USD, while electricity sales are in local currency and tariffs are capped. Furthermore, in hydropower-dominated systems, hydropower plants tend to be dispatched first when there is abundant water because of their lower variable (fuel) costs than thermal power plants. But gas-fired plants need to operate at high load factors to be attractive to investors (through lower cost per kWh of electricity produced).

While the situation in Brazil's power sector is certainly complex, based on the fuel mix of plants currently under construction, the sector seems poised for change.

The mix of Brazilian plant under construction is certainly significantly different from the current generation mix, where the largest share comes from hydropower. Although almost half of the capacity under construction is gas-fired, none of those gas plants are reported to be in the efficient "combined cycle" process. However, some gas turbines in single cycle – less efficient than in combined cycle – are planned to be converted into combined cycle in a later phase. This would help mitigate the upward pressures on the GHG intensity of Brazil's power sector, from increased gas-fired power generation.





[15] See IEA 2002 forthcoming for a more detailed discussion on the Brazilian power sector situation and prospects for

3.1.1 Data Collection and treatment

Prof. Roberto Schaeffer and André Felipe Simões of the Energy Planning Program, COPPE at the Federal University of Rio de Janeiro, were responsible for compiling the Brazilian data on 1,479 power plants, either in operation (1,174 plants) or under construction (305 plants), in the country as of July 3, 2002. These plants are situated in cities/towns covering all the Brazilian territory (i.e. in the 27 states). Grid connected power plants feed electricity to either of the country's large grids: N-NE (regions North and Northeast), and S-SE (regions South, Southeast and Mid-west).

The plant-level data was gathered mainly from ANEEL, the institution responsible (since the end of 1997) for the collection of plant-level data in Brazil. However, given some companies' difficulties in reporting their data, other sources were also consulted, e.g. Eletrobras[16] and some plant managers. Nonetheless, most of the necessary data could be obtained. In cases where data were unavailable, assumptions were made by the Brazilian experts to fill some gaps (see below). The only area where data gaps could not be filled was for dates regarding the beginning of operations for individual electricity units. For many plants, no start-of-operation dates were specified, which may affect the accuracy of the "build margin" calculations if these grid-connected plants without dates were in fact all built recently.

The following are main assumptions made with respect to the construction of the database for calculating emission baselines:

- It was assumed that only auto-producers power plants could be classified as "off-grid" plants. Other plants, i.e., plants characterised as independent power producers and those directly linked to the public sector, were assumed to be grid-connected.

  This was based on information gathered from several references, indicating that auto-producer plants supply particular communities, usually isolated, characterised by difficult access, normally fuelled with diesel oil in the North of Brazil. In the case of independent power producer plants, they tend to obtain part of their profit from the sale of electricity. In this case, those plants would integrate into the grid.

- The geographic location of each plant determined the grid in which the plant feeds electricity.

- <u>Start of production date</u>: To determine the initial date of production of plants still *under construction*, an average time of construction was assumed for each kind of plant, based on the references available. The current stages of construction were taken into account.

  The start of production date for plants in operation was obtained for most plants from available data in the references. But, for 419 of grid-connected plants, this data was not available[17]. Together, these no-start-of-production-date plants generated 18 TWh, with hydropower plants representing 41%, and oil-fired plants 28%[18]. It is therefore possible that the number of missing dates could have an effect on the build margin baseline calculations, as most of these were assumed not to be most recent and thus not included in the *build margin* calculations.

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gas-fired electricity.

[16] Eletrobras is the holding of the State generating companies.

[17] Start-of-operation dates were also unavailable for 421 off-grid plants.

[18] A cross-check was also made with the UDI/McGraw Hill (2001) database to fill-in some of the start of operation dates and blanks (i.e. for 28 grid-connected and 16 off-grid power plants). However, due to lack of time and resources, all individual power plants could not be contacted.

- The *operating margin* (OM) baseline was calculated in two different ways: (i) biomass, wind, sun, and hydro were considered "low-cost/must-run resources" and thus excluded from the OM calculation; and (ii) given the predominance of hydropower in Brazil's electricity mix, an alternative OM calculation was done, subtracting 50% of total generation from hydropower generation, as per the suggestion in Kartha et al (2002) for operating margin calculations in hydro-rich countries (see Box 1). So, for example, this meant that in the N-NE grid, 50% of the 124,463 GWh generated (i.e. 62,231 GWh) was subtracted from the total hydropower generation of the grid.

- Although off-grid baselines were not the focus of this road-testing analysis, Brazilian experts were able to collect data on off-grid plants. The off-grid plant coverage is considered comprehensive: 3,433 MW in operation and 573 additional MW under construction.

- The mineral coal used in the Brazilian thermal power plants (1.5 GW usually located in the South of the country) is, according to the references, bituminous coal. However, for some plants, the operational data indicate the eventual use of sub-bituminous coal. A mix of bituminous and sub-bituminous was thus assumed for those plants (i.e. 2.83 GW from plants currently under construction).

- The biomass plants in operation have steam turbines for power generation. In all cases biomass plants were combined heat and power plants. The Brazilian experts calculated capacity factors for each biomass plant, based on power and energy data from ANEEL and Eletrobras.

- The fossil fuel conversion efficiency (%) for the thermal power plants was calculated based on the installed capacity of each plant and the electricity actually produced. For most of the fossil fuel power plants under construction, a constant value of 30% was used as an estimate for their fossil fuel conversion efficiencies. This assumption was based on data available in the literature and based on the observation of the actual situation of those kinds of plants currently in operation in Brazil. The only 2 natural gas plants in combined cycle (totalling 648 MW) were assumed to have a higher efficiency rate, i.e. 45%.

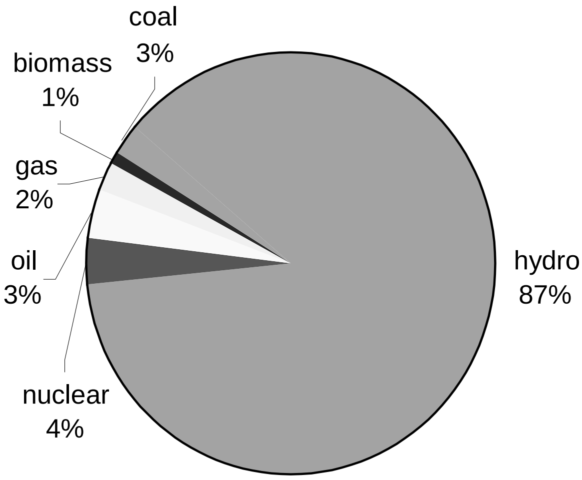
- In the case of plants in operation, capacity factors for thermal plants were calculated based on the data on installed capacity and electricity generated. In the case of hydro and wind, an average capacity factor was assumed for all plants, based on the "real average" for those plants (i.e. the capacity factor that can be observed, on average, for the plants in operation in Brazil): 56% for hydro and 22% for wind.

- For plants under construction, the capacity factor assumptions were based on information collected in the literature, in research institutes and public and private companies. The following capacity factors were used for plants under construction: Solar: 15%; Diesel: 30%; Coal: 75%; Wind: 22%; Natural gas: 75%; Hydropower: 56%; and Biomass: 75%.

3.1.2 Baseline Calculations

Tables below provide summary results for the baseline calculation for the country as a whole (Table 3.1a) and then for each grid separately (3.1b and 3.1c), as per the Kartha et al. (2002) recommendations. Figure 1 shows the current mix of electricity in Brazil, generating a total of 351 TWh in 2000.

Figure 1: **Brazil's total grid-connected power generation (2000): 351 TWh**



*Excludes plants under construction

A straight weighted average calculation of Brazil's total grid-connected power plants (i.e. both grids including plants in operation and those under construction) amounts to 243 tCO_2/GWh, reflecting the large share (64%[19]) of hydropower[20]. This can be a useful reference when considering the combined margin baseline calculations below.

Table 3.1(a): **Brazil's Electricity Sector – Grid and off-grid**

	tCO_2/GWh weighted average)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total grid-connected (both grids)	243	1058	113,957	571,259
Off-grid	221	421	4,007	21,107

Notes: The data include plants under construction.

Data collected indicate the following power mix for off-grid power generation: 40% from biomass; 31% from hydro; 16% from oil/diesel; and 10% from natural gas.

About 124 TWh generated by 476 plants feed into the North-Northeast grid (Table 3.1b), the smaller of Brazil's two electricity grids. Hydropower represents 71% of the grid's total generation, making it appropriate to use Kartha et al.'s recommendation for calculating the operating margin in hydro-dominated power systems (OM-ii)[21] (although both operating margin baseline calculation results are shown for information). This leads to a combined margin baseline of 336 t CO_2/GWh for potential projects supplying the N-NE grid.

[19] Hydropower represents a larger share when excluding plants currently under construction.

[20] Hydropower generation is assumed to lead to zero emissions.

[21] OM-ii refers to the operating margin calculation based on the system average minus a fixed share (i.e. 50% of total generation) of hydro. Kartha et al. (2002) recommend this in the case of hydro-rich countries. See Box 1.

Table 3.1(b): **Summary of Results - North-Northeast grid**

	Baseline Level (tCO_2/GWh weighted average)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total Weighted Average*	170	476	28,926	124,463
Operating margin (2 calculations):				
(i) OM - (system average minus low cost/must run resources)	774	350	6,761	27,593
(ii) OM (system average minus share of hydro)	341	452	16,241	62,233
Build Margin	331	98	9,740.1	38,042.2
Combined Margin (OM-i)	546			
Combined Margin (OM-ii)	336			

Note: Plants under construction are included in the calculations.
* Total generation mix of the North-Northeast grid: 70.9% hydro; 13.9% gas; 8.2% oil; 6.3% wind; 0.7% biomass

Table 3.1(c): **Summary of Results - South-Southeast grid**

	Baseline Level (tCO_2/GWh weighted average)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total Weighted Average*	275	582	85,031	447,081
Operating margin (2 calculations):				
(i) OM - (system average minus low cost/must run resources)	719	121	28,421	167,808
(ii) OM (system average minus a share of hydro)	550	527	39,462	223,541
Build Margin	569	116	28,521	169,750
Combined Margin (OM-i)	644			
Combined Margin (OM-ii)	560			

Note: Calculations include plants under construction.
* Total generation mix of the South-Southeastern grid: 61.5% hydro; 27.4% gas; 5.9% coal; 2.9% nuclear; 1.7% oil; 0.6% biomass; 0.1% wind.

In comparison, the combined margin baseline emission rate (excluding 50% total generation from hydro generation in the operating margin calculation) for the large South, Southeast and Mid-west grid is 560 t CO_2/GWh, reflecting a larger share of fossil fuel-generated electricity (i.e. 35% of the total), with natural gas being the main fossil fuel source. The combined margin baseline rate is pushed upwards by what is built at the margin: 72% of the total capacity (i.e. 28.5 GW) in the build margin calculation comes from fossil fuel plants, mostly gas-fired power plants accounting for 59% of the total build margin capacity and 65% of its power generation.

In the case of both grids, using the operating margin calculation that excludes a fixed part (50% of total generation) of the must-run/zero fuel cost hydro capacity (OM-ii), as opposed to excluding all renewable resources (in OM-i)[22], leads to a sometimes significantly lower combined margin baseline emission rate. In the N-NE grid, the combined margin, using OM-ii is 38% lower than the combined margin calculation based on OM-i. Similarly, the combined margin baseline emission rate using OM-ii for Brazil's S-SE grid is 13% lower than with the other operating margin (OM-i) calculation. In both cases, using the OM-ii calculation brings resulting OM-ii emission rate closer to the build margin (BM) calculation.

While the OM-ii calculation was recommended to address the concern that an operating margin calculation excluding all hydro and renewable resources (OM-i) would lead to an overestimation of the emission baseline, it may be considered too stringent in some cases. For example, as shown later in section 4 (and figure 4), the combined margin baseline emission rate (using OM-ii) for the North-Northeast Brazilian grid (i.e. 336 t CO_2/GWh) would effectively mean that combined cycle natural gas plants (which are more efficient that the single cycle plants currently in operation or under construction) –emitting about 380 t CO_2/GWh - could not generate any emission credits. However, excluding all hydro and renewable generation from the operating margin calculation (OM-i) would make the combined margin emission baseline rate higher (i.e. 546 t CO_2/GWh) and allow combined cycle plants to generate emission credits.

3.2 Chile

Total installed capacity in Chile was 10.4 GW in 2000 (CNE, 2000). Based on the data collected by Chilean experts, Chile's total electricity generation was 40.3 TWh in the same year. Growth in electricity demand has been steady at 7% per year. Electrification in Chile is high, with more than 95 % having access to electricity.

The Chilean power network consists of two large systems: the Sistema Interconectado Central (SIC) and the Sistema Interconectado del Norte Grande (SING) that generate over 94% of the total electricity production. The SIC and SING systems are not interconnected. The economic dispatch centre (CDEC) co-ordinates the operation of the corresponding interconnected system. There is one CDEC for the SIC system and another for the SING system. Any other electricity system with more than 100 MW of installed capacity must have its own CDEC. Each CDEC is controlled by the largest generators of the system where that CDEC operates. Two small independent systems and auto- producers complete the Chilean power sector.

Private generators, including auto-generators, represent about 90 % of the nationally installed generating capacity. There are 11 main generating companies, under private (majority) ownership. Ten private generators supply electricity to the SIC grid, with the largest generator being the privately owned ENDESA and its subsidiary enterprises that own approximately 55% of the SIC's installed capacity and

[22] OM-i refers to the general operating margin calculation based on the weighted average of all plants in operation, excluding facilities that that are both must-run and have zero fuel costs: hydro, geothermal, wind, low-cost biomass and solar. See Box 1.

supply about 52% of the system's total generation. Six generators feed electricity to the SING grid. The largest plant supplying the SING grid is the 1,008 MW Tocopilla plant, owned by the state-owned copper mining company (CODELCO) and a holding company. Many of the major mining industries located in the SING area have considerable auto-generation capacity, which they developed prior to the country's power sector reform.

Three government entities have primary responsibility for the implementation and enforcement of the Chilean Electricity Law:

- The National Energy Commission ("Comisión Nacional de Energía", CNE) proposes sector rules, improvements and changes; it determines node prices and added value for distribution; makes sector investment planning suggestions; reviews background information and prepares reports to settle CDEC conflicts.

- The Electricity and Fuels Secretariat ("Superintendencia de Electricidad y Combustibles", SEC) sets and enforces the technical standards of the system.

- The Ministry of Economy grants final approval of tariffs and node prices set by the CNE and regulates the granting of concessions to electric generation, transmission and distribution companies.

Reform in the Chilean electricity sector started two decades ago, when Chile introduced reform legislation aimed at bringing competition and private investment into the sector, defining the basis for the operation of electric utilities in a decentralised and privately owned industry. However, competition did not begin until the late 1980s. The main goals were (i) to provide open access to the transmission network; and (ii) to allow any entity to own and operate a power generation plant. The requirement for generating companies to be centrally dispatched by an independent operator was seen as a guarantee for the efficient operation of the system. However, actual results show that those objectives were only partially attained, mainly because, for example, the transmission network remained under ENDESA's ownership until 2001[23] and the ownership of dispatching centres, operated by the three main generators in the case of the SIC system, is highly concentrated. Also, for electricity stability reasons, it is not always the lowest marginal cost unit that is dispatched in the SING system[24].

In 1997, natural gas imported from Argentina began to challenge hydro and coal (the dominant sources in the SIC and SING respectively) in Chile's electricity sector. Since the entrance of the new gas pipelines from Argentina, most capacity additions have been gas-fired combined cycle power plants.

3.2.1 Data Collection and Treatment

Prof. Pedro Maldonado, of the Instituto de Asuntos Publicos at the University of Chile, was responsible for assembling the Chilean data. The main sources of information were found on the web sites of the Economic Dispatch Centers for both grids: *Centro de Despacho Economico de Carga for the Sistema Interconectado Central* (CDEC-SIC), and the *Centro de Despacho Economico de Carga for the Sistema Interconectado del Norte Grande* (CDEC-SING), as well as the National Energy Commission, *Comisión Nacional de Energía*, (CNE).

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[23] This situation introduced some limitations for other generators, especially new actors, to provide electricity to large users (over 2 MW) and distributors, no matter their location in the grid. In 2000, an ENDESA affiliate was created, TRANSELEC, to own and operate the SIC's transmission assets.

[24] This is why some natural gas combined cycle power plants are dispatched only partially, even if their marginal costs should result in a total dispatch order.

Basic data for monthly generation and power installed by power plant can be obtained from the operation statistics of the corresponding economic dispatching centre (CDEC). This information also includes the date of installation of each power plant or units. In the case of CDEC-SING it is also possible to obtain hourly generation data for free, once the interested person has become registered. On the other hand, obtaining more data from the CDEC-SIC requires a payment.

On-line documents containing daily generation by plant for both SIC and SING systems can be obtained from the *Comisión Nacional de Energía* (CNE) website. The specific fuel consumption for thermal power plants was obtained from the October 2001 documents on the determination of node prices, "*Fijación de Precios de Nudo, Octubre 2001, Informe Técnico Definitivo*" for each system[25].

Based on the sources mentioned above, the Chilean expert calculated appropriate annual load factors for each plant.

Considerable data on individual Chilean power plants is available to the public; the Chilean data-set is thus virtually complete for the purpose of this baseline calculation exercise. However, no data could easily be obtained on plants under construction (they are thus not included in the calculations). The following lists important data information and main assumptions that were made with respect to the construction of the database for calculating baseline emission rates:

- "Annual" and "maximum" (i.e. average of the three higher monthly load factors) load factors were provided by the Chilean expert. The annual load factor was calculated dividing annual generation divided by nominal power multiplied by 8760 hours per year. Table 3.2a below shows the difference between these two "loads".

- Some plants were reported to have a 0% load factor. They are not generating electricity because they have a higher marginal cost. These plants are normally in reserve only for very severe or extreme situations. They are thus not considered to be "in operation".

- For the calculation of the operating margin[26], biomass, wind, sun, and hydro are considered "low-cost/must-run resources."

- The data included 83 GWh from "other self producers" in the SIC grid, without any other information. These "self-producers" thus had to be excluded from the baseline calculations.

- Ten hydroelectric power plants (totalling 1.8 GW out of the 4.8 country's total hydro capacity) were identified by the Chilean experts as generating more electricity than expected given their nominal capacity power capacity. The Central Economic Load Dispatch Commission's (CDEC-SIC) explanation is that some *upgraded* plants have a real plant capacity greater than the nominal capacity.

- A total capacity was given for each plant along with the number of units. The plants were broken down by unit, and it was assumed that each unit produced an equal amount of capacity.

- Some of the plants listed contained a number of units, and instead of specific dates, a range of dates was listed for when the units came online, with the specific dates for each unit not specified. For these plants, it was assumed that half went online during the first year and the other half went online during

[25] The CNE prepares two reports per year (in Spanish) and access is free (www.cne.cl).

[26] It would also be possible to calculate the operating margin through a dispatch decrement analysis (OM3 in Kartha et al. 2002).

the final year. For example, if one plant had 6 units that went online between 1980 and 2000, three units were assumed to go online in 1980 and three in 2000.

Table 3.2a: **Chile - Difference between annual average load factor and maximum load factor***

	SIC GRID			SING GRID		
Fuel	% of total grid output	Average load factor	Average of Maximum load factor	% of total grid output	Average load factor	Average of Maximum load factor
coal	9%	22%	35%	29%	26%	74%
gas	19%	43%	67%	69%	48%	88%
oil	2%	13%	15%	1%	3%	36%
hydro	68%	59%	80%	1%	53%	81%
biomass	1%	61%	75%	-	-	-
Total	100%	52%	71%	100%	12%	88%

* The maximum load factor corresponds to each plant's average of the three higher monthly load factors.

3.2.2 Baseline Calculations

Based on the collected data, Figure 2 shows the composition of the Chilean fuel mix. While different sources are used to generate electricity, hydro represents the largest share with about half of total power generation in the country. However, sharp distinctions can be observed between the country's two grids, with the SIC grid (with 30.4 TWh) dominated by hydro-generated electricity (68%), while the smaller (9.8 TWh) SING grid is largely supplied by gas-fired electricity (69%). Tables below show what this means for emission baselines in Chile.

As was done for Brazil, baseline calculations are shown for the country as a whole in Table 3.2b. Tables 3.2c and 3.2d show calculations for each of the two grids, as per the baseline recommendations in Kartha et al. (2002).

Figure 2: **Total Electricity Generation in Chile (2000): 40.25 TWh**

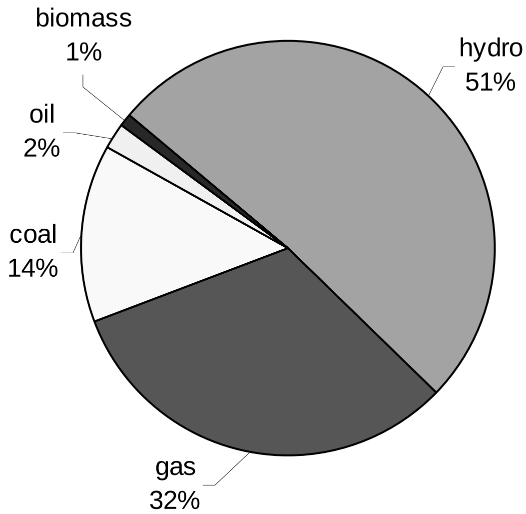

Table 3.2(b): **Chile's Total Electricity Sector (both grids)**

tCO_2/GWh weighted average (including all plants)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
283	173	10,208	40,256

In the case of the SIC grid, the build margin emission rate calculations (based on 23 plants that started their operations from 1996 to 2000) lead to a greater emission rate (i.e. 43% higher) than the total weighted average. This reflects a greater proportion of higher-emitting generating sources (compared to the existing stock) being installed on the margin. In fact, 62% of the generation from plants included in the build margin calculation were fossil fuel-based (i.e. gas or oil). The Kartha et al (2002) recommendation for calculating the operating margin (and thus excluding low cost/must run renewable sources) leads to 613 t CO_2/GWh, based on about 31% of total generation[27]. The combined margin of 442 t CO_2/GWh is higher than the build margin (by 63%), but lower (by 28%) than the operating margin. Only efficient gas power plants and zero-emitting power sources would lead to emissions below this combined margin baseline emission rate.

[27] The other operating margin calculation, recommended for power systems dominated by hydropower (as was done in the previous Brazilian case study), could potentially be applied in the context of the SIC grid.

Table 3.2(c): **Summary of Results – Chile's SIC grid**

	Baseline Level (tCO_2/GWh weighted average)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total Weighted Average*	190	108	6,729	30,675
Operating Margin(system average minus low cost/must run resources)	613	22	2,507	9,341
Build Margin	271	23	2,335	10,471
Combined Margin	442			

*Total generation mix of the SIC grid: 68.3% hydro; 19.4% gas; 9.4% coal; 1.7% oil; 0.01% biomass

Chile's smaller SING grid has a total capacity of 3.4 GW with 9.8 TWh of generated electricity (Table 3.2d). It has a significantly more GHG-intensive electricity mix, with fossil fuels (coal, gas and oil) generating more than 90% of the electricity.

Given the small amount of electricity generated from renewables (i.e. 0.06 TWh), the operating margin (OM) calculation (579 t CO_2/GWh) is almost identical to the weighted average emission calculations from all plants supplying the SING grid.

The SING build margin calculation is based on 14 units that started their operations between 1995 to 2001. The electricity generated by the 12 units is entirely fossil fuel-based, with 80.7% from gas, 19.1% from coal and 0.1% from oil.

Combining the operating margin and build margin results leads to a combined margin emission baseline rate of 540 t CO_2/GWh for Chile's SING grid, a level that is 22% higher than that of the other SIC grid. This is reasonable, given the greater fossil-fuel intensity of electricity supplying the SING grid.

Table 3.2(d): **Summary of Results – Chile's SING grid**

	Baseline Level (tCO_2/GWh weighted average)	Number of Plants/Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total Weighted Average*	576	65	3,421	9,812
Operating Margin(system average minus low cost/must run resources)	580	62	3,408	9,748
Build Margin	500	14	2,498	8,352
Combined Margin	540			

*Total generation mix of the SING grid: 68.7% gas; 29.3% coal; 1.3% oil; 0.7% hydro.

Box 3: The Prototype Carbon Fund's baseline calculation for Chile's SIC grid

➪Developing emission baselines for projects in the electricity sector requires estimating "avoided generation" through the examination of power generation on the margin. While Kartha et al. (2002) recommended a combined margin baseline methodology, the World Bank's Prototype Carbon Fund (PCF) adopted another approach.

The PCF (PCF, 2001) undertook an extensive baseline analysis for its purchase of emission reductions from Chile's Chacabuquito Hydro (run-of-the-river) Project (feeding electricity to the SIC grid). The PCF baseline was based on a projected dispatch analysis concluding that the hydro project would likely displace coal-based generation, leading to *estimated* emission reductions of 860 t CO_2/GWh. According to the PCF approach, *actual* emission reductions will be based on the marginal power plants displaced by the Chacabuquito project.

The PCF approach leads to a baseline emission rate that is almost twice as high as this study's combined margin emission baseline rate calculation for the SIC grid (i.e. 442 t CO_2/GWh) – where the build margin does not include any coal plants - making the combined margin methodology seem quite conservative in this case. Which one is "better", is difficult to determine. But a key difference is that while the Kartha et al. sought to combine effects on both plant operation and the building of new plants, the PCF approach seeks to determine the plant (in this a coal-fired power plant) that would be affected by the project. Also, Kartha et al.'s work was aimed at developing a baseline methodology that could be applicable to different electricity projects in different contexts (i.e. a "multi-project" baseline approach), the PCF approach focuses on one specific project. Furthermore, actual emission reductions may change significantly in the case of the Chacabuquito project if the marginal plant displaced is different, while the combined margin ex-ante calculation offers greater predictability. The transaction costs associated with the baseline calculations are also likely significantly different, with the PCF-conducted baseline analysis being more expensive. Nonetheless, the PCF estimated baseline is expected to lead to more emission credits – if a coal plant indeed ends up displaced - than the Kartha et al. combined margin, and this is a key consideration for potential project developers.

3.3 South Africa

South Africa's generating technology is based largely on coal-fired power stations, mostly concentrated near and to the east of Johannesburg – close to the main coal mining areas as well as the major demand centre. In fact, South Africa is the world's fifth-largest producer of coal, accounting for 97% of the total African coal production in 2000 (IEA, 2002). At the end of 2000, there were 50 power stations in the country, of which 20 are coal-fired, accounting for 90% of the total capacity of 43,142 MW (excluding capacity in reserve and under construction). Three older coal stations, and two units, representing a third of another plant, are currently in reserve because of excess capacity, and would add an additional 3,783 MW. The only non-coal stations of significance are the Koeberg nuclear station (4% of operational capacity) and three pumped storage facilities (also 4%) (NER 1999).

Generation and transmission of electricity in South Africa are dominated by the parastatal utility, Eskom, which owns and operates 92% of the country's generation capacity, with municipalities and private generators owning six and two per cent respectively. In 2000, total power generation capacity, excluding plants in reserve and retired, was 35.7 GW with total electricity generation reaching 201.4 TWh [28].

It is important to highlight the pivotal role played by the electricity supply sector in the South African economy. Its post-apartheid importance lies in its role not only as a key input to industrial development, but also in improving the quality of life for the previously disadvantaged majority. Electricity makes up 25% of final energy demand in South Africa, following coal and liquid fuels (DME 2000). This share understates the importance of the role of electricity as a high quality energy carrier and as a critical input to key economic sectors. On the industry and manufacturing side, the energy- and electricity-intensive industries are some of the largest contributors to economic growth and exports, and provide more than 60% of national electricity sales (Trollip 1996; Berger 2000; DME 2000).

On the household side, providing electricity to previously disadvantaged communities has been one of the more successful programmes of the government's Reconstruction and Development Programme (ANC 1994). Access to *affordable* electricity, through a mass electrification drive, is a key policy priority in the White Paper on Energy Policy (DME 1998).

The Government's policy of universal access to electricity has lead to a large electrification program which resulted in raising the national percentage of electrified households to 66% by end of 2001 (NER 2001), up from about 33% in 1993. There are sharp differences among urban and rural regions, with 74.2% of urban households and 45.7% of rural households having access to electricity. Unsurprisingly, those without access tend to be in the rural areas. Examples of efforts to provide electricity services to rural communities include the Eskom/Shell joint venture that installed some 6,000 solar home systems (50Wp). There are 350,000 systems in concessions, totalling 17.5 MW. Off-grid diesel usage is likely to be higher, but data is not readily available.

Box 4: South Africa's parastatal utility, Eskom

➪ Eskom is South Africa's primary electricity supplier, with 24 power stations and a nominal capacity of 40.6 GW. It supplies about 95% of South Africa's electricity requirements, representing more than half of the electricity generated on the African continent. It is among the top five utilities in the world in terms of size and sales. Eskom's industrial and residential electricity tariffs are amongst the world's lowest (SANEA 1998). This situation is attributable to several factors: (i) South Africa's vast coal resources, coupled with plants situated near the mines; (ii) municipal distributors and large industrial and mining customers contributing more than 80% of its sales revenue – these customers are both less expensive to serve and generally in a position to negotiate favourable prices; (iii) in the past, Eskom did not pay tax or dividends to the government; and (iv), the price of electricity, as is the case in many countries, has never included any part of the environmental and social impacts of electricity generation.

[28] As a basis of comparison, IEA statistics indicate that South Africa generated 200.4 TWh in 1999 and 207.7 TWh in 2000.

3.3.1 Data Collection and Treatment

Harald Winkler and Jean-Marc Lukamba from the Energy and Development Research Centre (EDRC) at the University of Cape Town, provided the plant-level data for South Africa.

The collection of data started with published statistical sources. The most important are the National Electricity Regulator (NER 2000) and earlier yearbooks published by Eskom (Eskom 1995, 1996). Eskom also publishes annual environmental reports (Eskom 2000). However, there is no central data collection for municipal power stations. To supplement the published data, the experts contacted different organisations to solicit relevant data, compiling both published source information and information provided by power station or municipal managers.

Some (but not all) gaps could be filled through information on specific plants (e.g. on efficiency) obtained directly from Eskom and municipality-owned utilities staff. But several additional assumptions still needed to be made.

The following lists the main assumptions that were made with respect to the construction of the database for calculating baseline emission rates:

- For the calculation of the operating margin, biomass, wind, sun, and hydro are considered “low-cost/must-run resources” and thus taken out of the operating margin calculation, as per the Kartha et al. recommendations.

- The capacity factors are, for the year 2000, based on NER statistics. They are calculated by multiplying the maximum power produced times 8760 hours/year and then are divided by the energy sent out.

- For the plants that were missing values for fossil fuel efficiency (i.e. 12 plants, totalling 1.7 GW), the average of other plants with an identical fuel type and the same technology was taken. The following efficiencies were assumed for the following technologies and fuel types:

  - Diesel in a gas turbine: 35%
  - Bituminous coal in a steam turbine: 30%

- No information on the efficiency of the bagasse/coal-fired plants (5 units totalling 106 MW) used by sugar and pulp and paper manufacturers, could be found. It was assumed that 25% of the bagasse/coal mixture was made up of coal and 75% was made up of bagasse.

- No start-of-operation dates were provided for plants representing a total of 3.7 GW. Consequently, these plants are not included in the build margin calculations, but are included in the operating margin calculations, if appropriate. It must be noted that the plants without start of production dates are mainly municipal power stations and some autoproducers (e.g. sugar mills using bagasse and some coal for power generation), as Eskom has published the data for its plants. Generally, municipal plants are older, so they would most likely not be suitable for the build margin calculation in any case.

- Some of the plants listed contained a number of units and only a range (rather than specific) dates are available for when the units came online. As in the case of Brazil, it was assumed that half went online during the first year and the other half went online during the final year. For example, if one plant had 6 units that went online between 1980 and 2000, three units were assumed to go online in 1980 and three in 2000.

- South Africa has not had many new grid-connected plants built in the past decade (only 1 in the past 7 years). The build margin calculation thus includes units built from 1987[29] until when the data was gathered. However, the units built in 1987 might not be perfectly representative of the type of units that would be built in South Africa in the future[30].
- South Africa has excess capacity and 3.8 GW (21 units from four plants*)* that are on reserve (or in storage not generating power). These were not included in the calculation of the operating margin. However, given the potential for re-commissioned these plants in the future, it was assumed that an increase in electricity demand could be met by firing these plants and so they were included in the build-margin calculation.
- As no fuel efficiencies are published for plants on reserve, the average efficiency for coal-fired Eskom power stations for Camden, Grootvlei and Komati were used for coal-fired stations in reserve.
- With present excess capacity in South Africa, "maximum power" (i.e. the maximum that was sent out by the station) is generally less than "licensed capacity" (i.e. the nominal capacity that was licensed). The "maximum power produced", not "nominal power," was thus chosen to calculate baselines.

3.3.2 Baseline Calculations

Figure 3 shows the fuel mix used for the South African power plants' power generation based on the collected data (i.e. 201.4 TWh). Coal-fired power plant supply more than 90% of the country's total generated electricity.

Table 3.3a presents the baseline calculations for grid-connected projects in South Africa. In the sub-set of plant data used to calculate the operating margin (917 t CO_2/GWh), 93% of the power generation is coal-fired. The operating margin emission rate is thus only slightly higher (i.e. 2.3%) than the weighted average emission rate of all plants, given that there were only 12 hydro plants representing 2% of total power generation to exclude from the operating margin calculation. However, in the South African electricity context, must-run resources are usually coal-fired, rather than renewables (these latter have low load factors indicating that they are not used "all" the time). The rationale used for excluding generation from renewables from the operating margin calculation might not apply in this case.

As mentioned above, the build margin calculation is made somewhat awkward given the country's situation of excess capacity and little investment in power generation plants over the past couple of years. Nonetheless, a build margin was calculated, based on the power generation of the most recent units from several plants[31]: Mujaba, Kendal Matimba, Tutuka, as well as three plants currently on reserve: Komati, Grootvlei, and Camden[32]. These were all coal-fired power plants with fuel conversion efficiencies ranging form 31.9% to 35.3%, resulting in the build margin emission rate of 980.8 t CO_2/GWh.

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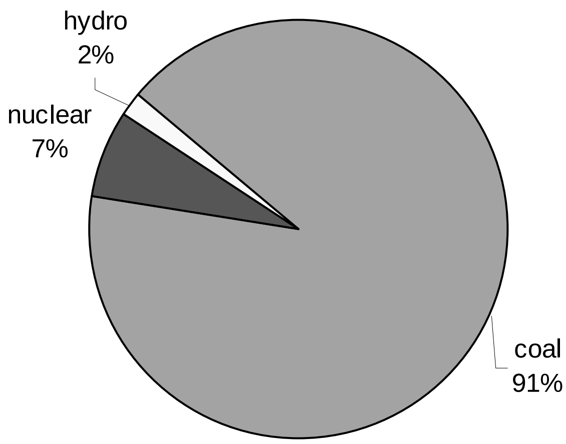
[29] These units are part of plants that had other units built more recently.

[30] Given the particular South African situation, and to avoid "gaming" from too forward-looking baselines, Winkler et al. (2001) developed a baseline that include "near future" plants. Their baseline is calculated based on the only power station (coal) being commissioned in the past seven years, 2 units of (coal) plants on reserve, and assumed future importation of hydro and a new gas plant.

[31] Some of these plants also have much older units, but only the most recent units were taken into account.

[32] Given that the units of some plants were build in the same year, making the selection of 5 plants (as per the Kartha et al. recommendation arbitrary) was arbitrary, so 7 plants were included in the build margin.

Figure 3: **South Africa's total power generation (2000): 201.4 TWh**



The combined margin emission baseline rate for South Africa is 949 t CO_2/GWh, which would mean that all eligible non-coal fossil fuel plant projects would lead to lower emissions than the baseline. This could work to be an incentive to consider more actively non-coal options for the heavily coal-dominated South African power sector.

Table 3.3: **Summary of Results – South Africa**

	Baseline Level (tCO_2/GWh weighted average)	Number of Units	Total Capacity(MW)	Total Electricity Output (GWh)
Total Operating Margin (all plants)	897	128	36,308	201,353
Operating Margin(system average minus low cost/must run resources)	917	103	33954	196,837
Build Margin	981	27 (from 7 plants)	12,118	66,277
Combined Margin	949			

4. Analysis of Road-testing Experience and Results

Collaborating with in-country experts greatly facilitated the data-collection exercise necessary to test the baseline recommendations, compared to undertaking the task from abroad. A comparison with IEA statistics (IEA, 2002)[33] on total generation for the three countries suggests that the plant-level data sets used for this project were at least consistent with other data – although it is impossible to ascertain if they are truly complete.

If Brazil, Chile and South Africa are representative of other potential host countries for CDM-type projects, differing levels of data quality and availability can be expected between countries. Chile is the "tested" country where grid-connected plant-level data is most comprehensive and readily available. However, the Brazilian data-set included data on plant under construction, as well as off-grid power plants (although the latter was not the focus of this baseline analysis), which were not available in the two countries.

While Chile could probably not be considered the "norm" in terms of data availability, it was still possible to build a full data-set to calculate operating and build margin baselines emission baseline rates for all countries by grid. But time was needed to do some additional research to fill-in some of the blanks and/or make assumptions in the cases of Brazil and South Africa. Table 4 provides a summary of the main data issues encountered during the road-testing.

[33] IEA statistics are based on national totals and do not include plant-level data.

Table 4: **Summary of Baseline Data Issues Arising from the Road-Testing**

Data Issues	Comments/Remarks
➢ Start-of-operation date missing in several instances.	In all three countries, there were some data gaps for some plants. Follow-up research could not fill all gaps (other than by contacting each plant individually). Depending on the quantity of missing data, making such contacts could be time consuming. These gaps could have an impact on the build margin emission rate calculation if the plants without start-of-operation dates were in fact built recently. However, it was not a major stumbling block in cases examined.
➢ Data on plant load factors and efficiencies not always available.	While load factors were not given, they could easily be calculated based on the information on the installed capacity and the electricity generated. Fossil fuel conversion efficiency (for thermal plants) could be calculated with information on the capacity, the electricity generated and fuel consumption; or conversely, reasonable assumptions could be made based on other similar plants in the country, or based on the literature.
➢ Information was more difficult to obtain by unit (versus the entire plant)	Typically, individual units of plants that are coal-fired, gas in combined cycle or hydropower, are of the same size - and this is the assumption that was generally made – (albeit with some exceptions). Also, individual units do not necessarily have the same start-of-operation date, as some plants undergo expansions at different times. In Chile and South Africa, a range of dates was usually obtained for plants with units starting at different dates. So assumptions had to be made as to how many units started operating when; these assumptions were time-bound by the data available, thus reducing the magnitude of the possible errors – which would only affect *build margin* calculations.
➢ Data on plants under construction seem more difficult to collect.	Information on plants under construction could be collected only in Brazil. Such information was not available for Chile, and South Africa does not have plants currently under construction. Where information is available on plant capacity, some assumptions need to be made on their load factors and efficiencies. Relying on information on other similar plants or from the literature can limit the magnitude of potential errors. Plants under construction are part of the build margin calculation in any case, so imprecise starting dates are not problematic. But not including plants under construction because of lack of data does introduce a bias in the baseline calculations.

Note: These issues arose in the context of road-testing the baseline recommendations in Brazil, Chile and South Africa. They may not be representative of other countries.

While there were some data gaps and some assumptions[34] needed to be made for some plants, the margin of errors are generally not thought to be significant, especially with respect to their impact on the overall combined margin baseline emission rate. Because the Kartha et al. (2002) baseline recommendations for grid-connected electricity projects are based on historical data or data on plants already under construction, there is little – or less- room for speculation or gaming, as opposed, for example, baseline methodologies relying on projections or expansion scenarios. The Kartha et al. recommended baseline methodology for grid-connected electricity generation projects is also easily implementable, with only basic knowledge of Excel spreadsheets being required. No energy sector modelling or detailed dispatch analysis is required, making the combined margin baseline emission rate fairly simple to calculate. Nonetheless, it obviously is a more time/resource-consuming calculation than a simple weighted average emission rate based on a country's total power generation by fuel (e.g. using IEA statistics) – but this calculation has been often considered not adequate to represent what would otherwise happen (e.g. Bosi 2000).

The main baseline challenges encountered in implementing the Kartha et al recommendations were (i) the build margin calculation for South Africa given its excess supply; and (ii) the determination of what exactly to include in the *operating margin* calculations, particularly in systems dominated by a single fuel.

For countries where little capacity has been built in recent years, such as in South Africa (as well as many potential JI host-countries), it is more difficult to assess the reasonableness of *build margin* calculations. With only one plant being built in the last seven years, the South African build margin emission rate in this study was calculated based on units that were built as far back as 1987. It is reasonable to question whether this result would represent a "best guess" of the type of power generation facility that would otherwise be built in the absence of a CDM or other GHG-mitigation electricity project. Nonetheless, given South Africa's vast coal reserves, a coal-based build margin that includes the few recent plants and those on reserve is probably not completely out of line – even if it is perhaps not sufficiently representative of different possibilities. The inclusion of the operating margin which includes some nuclear, makes the South African combined margin emission rate slightly lower than the build margin, while still providing incentives to consider lower GHG-emitting sources for any future expansions met by CDM projects. Some have suggested including possible future expansions in lower GHG-emitting electricity capacity in the baseline calculations (e.g. Winkler et al. 2001, and CERUPT 2001), but as noted in Kartha et al. (2002), this introduces additional requirements for developing baselines and involves some "guessing" which may make the baseline process less predictable, while still being different from what really happens. Winkler et al. (2001) sought to address this concern in their consideration of baselines for grid-connected projects in South Africa by including "factors that are difficult to change", such as requiring that any projection be based on published or utility plans. So their baseline calculation (i.e. 836 t CO_2/GWh; 12% lower than the combined margin baseline emission rate), which is also a weighted average emission rate from a sample of plants, is based on two most recent units built in South Africa, the recommissioning of two units of plants currently on reserve (these are also included in the build margin of this study), as well as "near future plants", i.e. 1.84 TWh of imported hydro, and a new 736 MW gas plant (with assumptions made on the technology for an eventual South African gas-fired plant). They argue that the assumed "near future" plants are reasonable, given the directions set by Eskom's electricity plan.

There is no way to determine with certainty which baseline calculation approach would lead to a better estimate of the "true" baseline. Periodically updating the system's combined margin baseline would ensure that future projects are assessed against a baseline, which takes into account most recent developments. But until developments occur in electricity systems that have not had many capacity additions in recent years, such as South Africa, a *build margin* baseline emission rate, calculated according to Kartha et al.'s recommendations might not be very relevant. Would a baseline based only on the operating margin be better? Or, would a "near future" baseline, more sophisticated but also implying more

[34] Consistent assumptions need to be made in similar circumstances.

judgement, be better? In the interest of developing some default baseline calculation methodologies that could be applicable to different circumstances, it would be useful to further examine the question of baselines in the context of other countries with little recent capacity additions. Feedback from experts in those countries would also help enlighten such a discussion and perhaps reach some consensus on most suitable and appropriate approach(es).

Kartha et al (2002) examined different approaches to calculating an *operating margin* emissions rate prior to recommending an easy-to-calculate approach. They noted, however that excluding all facilities that are both must-run and that have no associated fuel costs from the operating margin calculation might not always be adequate, as it might lead to a baseline emission rate that is too high. So, for hydro-rich countries, they suggested a simplified option to address the concern that such an operating margin calculation would lead to an inflated baseline. This could be done by excluding a fixed percentage of hydropower generation, e.g. 50% of total generation. It is clear that this is a rather arbitrary figure, but a figure of similar magnitude might be necessary to have a more "realistic" baseline. However, additional work might be warranted to further examine the implications such an operating margin calculation for hydro rich countries in terms of the resulting stringency of the combined margin baseline emission rate. In addition, specific guidance would need to be elaborated to clarify in which circumstances such an *operating margin* calculation should be undertaken (e.g. systems where a given high share of the total generation comes from hydropower). Other options could also be examined, such as a "sliding scale" based on the relative share of hydro in a system's electricity mix[35], to calculate a more appropriate operating margin emission rate for hydro-rich systems.

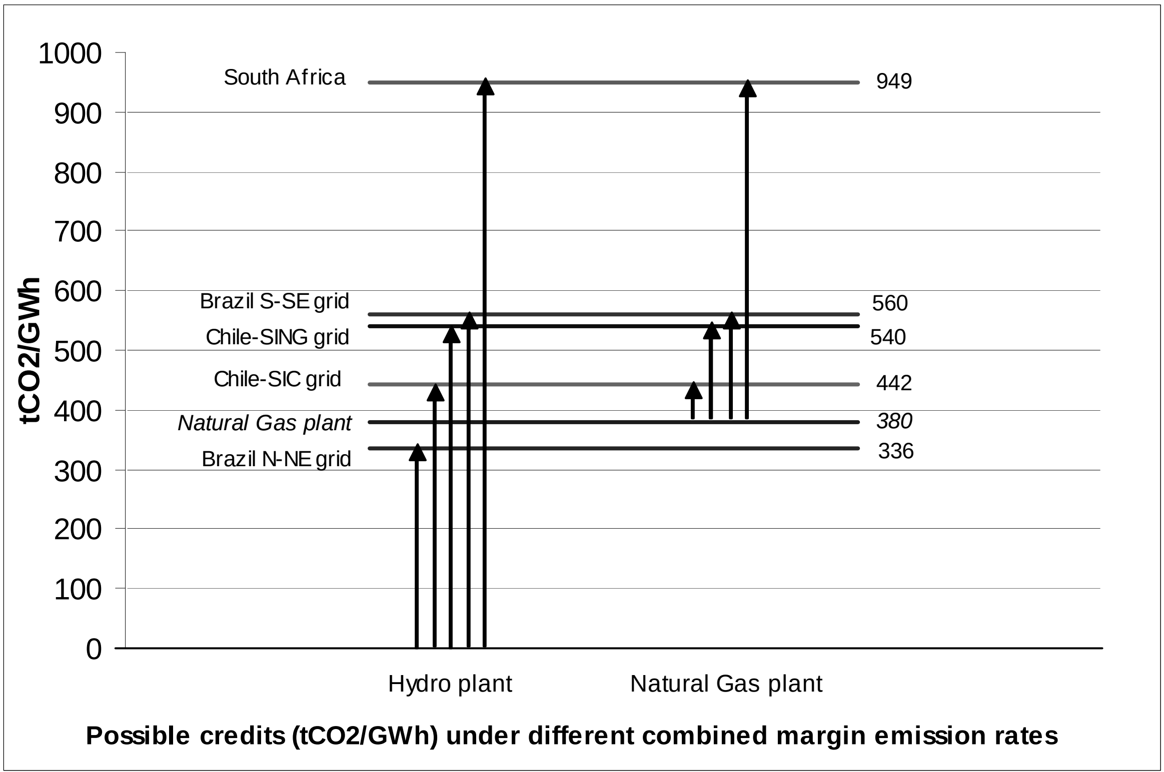
The recommended operating margin calculation might also not be appropriate for systems dominated by fossil fuels that are locally available, cheap and abundant, as in South Africa. In this case, coal-fired power plants are the must-run facilities; not hydropower and biomass plants. One possibility could be for the *operating margin* calculation to include the zero-emissions plants (recognising that at least in South Africa, they would probably not make a significant difference to the emission baseline given their low share -- i.e. 2% of total generation). However, this would effectively lead to a simple weighted average emission rate, which is not considered sufficiently accurate. Further examination of this type of situation (i.e. heavily fossil-dominated systems) and possible ways to develop a more appropriate operating margin are warranted.

It should be noted that the recommendation to develop emission baselines for each major grid in a country means that different circumstances, even within a country, can be taken into account (e.g., as in the case of the Chilean grids and the two Brazilian grids (Figure 4)). The development of baselines in situations of connected grids (not examined here) might warrant particular consideration in future work, however.

While the combined margin baseline recommendations can be rather easily applied to different contexts, as has been done in this study, it is obvious that the recommended baseline calculations lead to different quantities of emission credits being earned by similar projects implemented in different circumstances. This situation is illustrated in Figure 4 below.

[35] For example, systems with 90% or more of their total electricity generated via hydropower could exclude a fixed percentage of hydropower from the operating margin calculation; while systems with 80 to 90% hydropower could exclude a higher percentage of hydropower from the operating margin calculation (i.e. moving the baseline a little higher), etc.

Figure 4: **Emission Reductions by Hydro and Natural Gas Projects**



Such an outcome, while possibly seeming "unfair", is to be expected if credits are to be awarded for emission reductions from displaced electricity in countries that have significantly different situations, because "what would happen otherwise" is also significantly different[36]. For example, a combined cycle natural gas plant in South Africa could earn 569 credits per GWh, but zero in Brazil's N-NE grid. Whether "fair" or not, low GHG-emitting CDM electricity projects implemented in countries such as South Africa will lead to greater reductions in global emissions compared to other countries with a less GHG-intensive power sector. A larger volume of credits will certainly help attract investors interested in CDM projects as discussed in the next section, but other factors, as discussed below, also need to be taken into account in such decisions. However, such an outcome can also be considered as disadvantaging those countries that opted, earlier, for less-GHG emitting sources of generation. Determining whether such outcomes are "reasonable" is a matter of judgement.

[36] For additional discussion on electricity baseline implications in different countries, see, for example, Bosi 2000 and Lazarus et al. 1999.

5. What could it mean for the economics of projects?

Road-testing the baseline recommendations requires looking at their practicality in terms of calculations and examining the reasonableness of the results in terms of the baseline emission rate. It is also important to consider what these recommendations could mean, in economic terms, for potential project developers. Measured against the recommended baselines, do GHG-friendly electricity projects lead to valuable emission reductions that could render such investments more attractive?

Three hypothetical projects are examined in the context of the road-tested countries: a small-scale 10 MW hydro plant (in Chile), a 10 MW wind plant (in Brazil and South Africa), and a 100 MW gas-fired power plant (in Brazil, South Africa and Chile). They are assumed to be validated CDM projects leading to emission reductions additional to what would otherwise occur[37]. Table 5.1 shows the calculation results if the projects were validated as CDM projects and thus could earn certified emission reduction (CER) credits. The credit revenues are calculated using a range of prices: USD 5/tCO_2, USD 10/tCO_2, and USD 20/tCO_2. These potential CER revenues are also compared to the estimated total project costs.

Of course, a decision on whether or not to invest in a particular potential CDM project is usually based on several factors, such as the internal rate of return, the payback period, the net present value, capital constraints, as well as opportunity costs, etc. The calculations below show only part of the picture, but information on the revenues that could be expected from emission credits presented in relation to a plant's costs is likely to be an important consideration.

Transaction costs associated with obtaining the recognition or certification of relevant authorities (e.g. national governments and the CDM Executive Board) of the emission reductions are not included in the calculations below. According to cost estimates surveyed in Bosi 2001, CDM-related transaction costs could amount to about USD 100 000. Such costs would of course decrease the economic attractiveness of the potential CDM projects, especially smaller projects[38]. It is also important to keep in mind that these transactions, unlike CER revenues, do not vary with the price of emission credits.

South Africa, with its very GHG-intensive electricity sector leading to a high combined margin baseline emission rate, clearly looks like an attractive location to consider implementing a CDM project in the electric power sector. Excluding CDM-related transaction costs, a 10 MW wind CDM project in South Africa could result in CER revenues from USD 729 090 to USD 2 916 260, depending on the market value of the CERs. These would represent 6.3% of the estimated plant costs at a low CER value or 25% of the total costs if the CERs could be sold at USD 20/t CO_2. A CDM project consisting of a 100 MW combined cycle gas plant in South Africa could earn even larger revenues due to the greater volume of emission reductions and thus CERs that it could generate. Based on the recommended combined margin baseline, and the fact that there are currently no wind nor natural gas plants in South Africa, the CDM could potentially be an attractive mechanism to help lower the GHG-intensity of the South African sector. However, any CDM grid-connected project, even with a significant volume of CERs, would still need to compete in an environment where coal resources are abundant and cheap, and coal technology is well-known.

[37] See Annex II for a graphic overview of the entire Kartha et al. recommended project and baseline evaluation process.

[38] However, the simplified modalities and procedures for small-scale CDM projects under development by the CDM Executive Board are aimed at decreasing the transaction costs for smaller projects.

In Chile, CERs could make a CDM 10 MW hydro plant supplying the country's larger SIC grid attractive by reducing annual emissions by 22,874 t CO_2[39], under the SIC's combined margin. But the CDM's contribution to reducing the project's overall costs is rather small (i.e. 2.2%) when CERs are only worth USD 5/tCO_2. And this is without taking into account any CDM-related transaction costs.

A 100-MW combined cycle gas plant also supplying Chile's SIC grid that is considered additional would lead to 40,734 t CO_2 per year, worth 2 to 5 million USD over a 10 year crediting period. But these revenues would still represent a rather small amount compared to the total costs of the project. Nonetheless, in some cases, depending on the investors' criteria, such CDM projects may still be attractive compared to other alternatives.

For Brazil, three projects are examined: a 10 MW windfarm supplying the N-NE grid, another 10 MW windfarm but supplying the S-SE grid, and a 100 MW combined cycle gas plant supplying the S-SE grid. Not surprisingly, the 10 MW wind project is more attractive, as a CDM project in the S-SE grid than in the N-NE grid due to the greater emission reductions (i.e. 40% more) resulting from a higher baseline. The credit value contribution to reducing overall costs of the wind plant remain small in absolute and relative terms, however, at low carbon prices.

In all three examples in Table 5, a 100 MW plant would generate larger volumes of emission credits and credit revenues than other projects due the significantly greater electricity produced. However, in the case of Chile's SIC grid and less so in Brazil's S-SE grid, the relative contribution of these credits is rather small (0.8% and 1.3% respectively) at low carbon prices, making CER a potentially minor consideration for potential power plant investors.

[39] Under the PCF's analysis of its 26 MW Chacabuquito project, the hydro project leads to a significantly greater volume of emission reductions (i.e. 137,600 t CO_2 per year) due to the larger size of the project, but also due to the use of a more GHG-intensive emission baseline (i.e. 860 tCO_2/GWh). Under the PCF coal-based baseline scenario, the economic attractiveness of the CDM hydro project in Chile is clearly enhanced.

Table 5: **Examples of CER Value for Electricity Projects**

Proposed Project	Total Cost without CER revenue	Combined Margin Baseline (tCO_2/GWh)	Emission Reductions per year (tCO_2)	CER Revenue @ \$5/tCO_2 (as % of total Costs)	CER Revenue @ \$10/tCO_2 (as % of total Costs)	CER Revenue @ \$20/tCO_2 (as % of total Costs)
South Africa- 10 MW wind farm [(1)]	\$11,589,102	949	20,761	729,090 (6.3%)	\$1,458,180 (12.6%)	\$2,916,360 (25.2%)
Brazil (N-NE grid) - 10 MW wind farm [(1)]	\$11,589,102	336	7,358	\$258,412 (2.2%)	\$516,823 (4.5%)	\$1,033,646 (8.9%)
Brazil (S-SE grid) - 10MW wind farm [(1)]	\$11,589,102	560	12,264	\$430,686 (3.7%)	\$861,372 (7.4%)	\$1,722,744 (14.9%)
Chile (SIC grid) Mini Hydro – 10MW [(2)]	\$36,399,220	442	22,874	\$803,318 (2.2%)	\$1,606,637 (4.4%)	\$3,213,274 (8.8%)
Brazil (S-SE grid)- 100 MW Natural Gas Plant [(3)]	\$181,812,004	560	118,260	\$4,153,044 (2.3%)	\$8,306,088 (4.6%)	\$16,612,175 (9.1%)
South Africa-100 MW Natural Gas Plant [(3)]	\$181,812,004	949	373,176	\$13,105,160 (7.2%)	\$26,210,321 (14.4%)	\$52,420,641 (28.8%)
Chile (SIC grid)- 100 MW Natural Gas Plant [(3)]	\$181,812,004	442	40,734	\$1,430,493 (0.8%)	\$2,860,986 (1.6%)	\$5,721,971 (3.2%)

[(1)] Investment costs: USD 1000/kW, Operation and maintenance costs: 1.5% of total investment costs per annum, Crediting lifetime: 10 years, Discount rate: 7%, Load factor: 25%, Annual generation: 21.9 GWh.

[(2)] Investment costs: USD 3000/kW, Operation and maintenance costs: 1.6% of investment cost per annum, Crediting lifetime: 10 years, Discount rate: 7%, Load factor: 59.08%, Annual generation: 46.6 GWh.

[(3)] Technology: combined cycle, Investment costs: USD 500/kW, Operation and Maintenance Costs: 1.5% Fuel efficiency: 53% Fuel Costs: 2366.8 USD/TJ, Load factor: 75%; Crediting lifetime: 10 years; Discount rate: 7%;Annual Generation: 657 GWh

6. Conclusions and Implications for the Baseline Recommendations

Developing emission baselines against which emission reductions from project activities are assessed has been described as an exercise of "estimating the unknown" (OECD/IEA, 2000).

Emission baselines are key to implementing any project-based mechanism, such as the CDM, or credit-based system. Credible and workable baseline guidance is desirable, seeking to balance criteria of environmental integrity, low development cost, transparency and a reasonable degree of crediting certainty. In their "Practical Baseline Recommendations for Greenhouse Gas Mitigation Projects in the Electric Power Sector", Kartha et al. (2002) sought to develop emission baseline methodologies that could serve as "default" methodologies for assessing GHG reductions by projects implemented in the electricity sector. (Although the Kartha et al. analysis and recommendations focussed on baselines for CDM projects, they may apply equally well to electricity projects implemented in other contexts.) This paper tests their recommended *combined margin* baseline emission rate for grid-connected projects.

This study of three different national contexts shows that the baseline recommendations could be implemented in all electricity systems examined. However, a closer look at the implications of some of the results suggests that some refinement of the baseline recommendations may be called for in certain situations. The following are the main conclusions/insights that can be drawn from this "road-testing" in the Brazilian, Chilean and South African contexts:

- <u>Data availability</u>: Types of data and data availability varied between countries, with Chile being the country where grid-connected plant-level data is most comprehensive and readily available. However, in Brazil, it was possible to collect data on plants currently under construction, as well as comprehensive data on off-grid power generation plants (although the latter are not the main focus of this project). Data gaps (especially with respect to the start-of-operation dates) did require additional research and making some assumptions, with likely limited error implications for the baseline emission rate. Although this required some time (and money), its was possible and relatively straight-forward to build a full data-set[40] to calculate *operating* and *build margin* emission rates, and the recommended *combined margin* baseline emission rate for each of the two grids in Chile and Brazil, and for South Africa's national electricity system. Should the *combined margin* methodology be identified as a possible default baseline methodology, efforts should be made to ensure that the necessary data is regularly collected, publicly available, and easily accessible as possible. At a minimum, authorities could inform project developers of relevant data sources for each power system. This could be particularly important for the feasibility of small-scale GHG-reducing projects.

- <u>Build margin calculations</u> (i.e. based on most recent plants and those under construction): Calculating a *build margin* emission rate in countries with very little recent capacity additions, such as South Africa, is challenging. The Kartha et al. recommendations relies on the most recent five plants (at a minimum). This led to a coal-based *build margin*, which may not be unrealistic in the context of South Africa's abundant coal reserves. The *combined margin*, which weighs the *operating margin* emission rate (which includes non-coal plants) at 50% with the other 50% for the *build margin*, does seem to help yield a more balanced outcome. However, other approaches such as a build margin baseline including assumptions on "near future" plants based on published literature from relevant electricity authorities might be worth considering further, as a possible "default" baseline methodology for electricity projects in countries with little recent capacity additions. Looking at other countries with such circumstances, and inviting views from experts in those countries could also be useful to see if

[40] Without examining a greater number of countries, it is difficult to make a more general assessment of the data availability.

there is some consensus around most suitable and appropriate – as well as workable - approach(es) to deal with circumstances of countries in over-capacity.

- Operating margin calculations: There is a concern that an *operating margin* which excludes must-run and zero-fuel cost plants (i.e. hydro, wind, solar and some biomass) may lead to overestimating the emission baseline in the case of hydro-rich countries (e.g. Brazil). In this case, Kartha et al. therefore suggested excluding a fixed (arbitrary) percentage of hydropower generation (e.g. 50% of total generation). This results in a lower *operating margin* baseline emission rate, as shown in the case of Brazil. Analysis presented here suggests refining this approach further, so as to clearly specify the threshold for adjusting the *operating margin* calculation: e.g. electricity systems where a given high share of total generation comes from hydropower. That exact share or threshold of hydropower in the total generation mix should be fixed in advance. Determining an appropriate threshold would also benefit from further examination of other "hydro-rich" countries and experts' views. Other options are possible and merit further consideration, such as a "sliding scale", to calculate the operating margin emission rate from hydro-rich countries.

  While the recommended operating margin calculation might be adequate in most electricity contexts, it does not seem always appropriate to exclude renewables from the *operating margin* calculations, on the grounds that they are must-run and have zero fuel costs. At the other end of the spectrum from the hydro-dominated systems discussed above, systems heavily dominated by fossil-fuel plants that are supplied by locally available, abundant and cheap fuel could also warrant particular consideration. In such cases, the fossil fuel plants (e.g. coal) tend to be used as must-run more than renewables plants. (South Africa is a good example.) One option, consistent with the discussion above for hydro-rich countries, might be to exclude a share of the coal-fired generation from the *operating margin* calculation.

- Applicability of the *combined margin* emission rate baseline: This methodology is definitely workable and can be implemented in different electricity contexts. It also results in consistent and transparent calculations of the emission baseline rates in different countries/systems. Although more burdensome than a simple weighted average emission rate based on national generation data by fuel, the use of grid-specific data ensures that the resulting emission rate corresponds to different circumstances. For example, such an approach allows distinguishing between parts of a country that have more GHG-intensive power generation with parts that are less GHG-intensive (e.g. Chile's SING and SIC grids). But as mentioned above, some refinements to take into account particular circumstances seem justified if this combined margin methodology were to be considered as a possible "default" methodology. Moreover, developing specific guidelines for making assumptions when data is missing would help ensure consistency in the development of baselines (and thus limit the potential for gaming).

  The *combined margin* methodology avoids the debate and "guessing" surrounding the identification of one particular plant that would be "displaced" by a CDM (or other GHG-reducing) grid-connected electricity project. It can also be applicable to more than one project (i.e., a "multi-project" baseline approach). However, the resulting emission rate is different in different countries and a larger quantity of emission reductions and thus credits could be earned by a natural gas plant or hydro plant in South Africa than in Chile or Brazil. This may be perceived as disadvantaging countries that have already adopted lower-GHG emitting electricity generation sources, since CDM-type systems aim at incremental improvements from a particular point in time. But this is necessary since the CDM or other systems are aimed at reducing emissions below "what would otherwise occur"- and not necessarily at encouraging particular GHG-reducing technologies.

- The economic benefits from GHG mitigation projects will depend on the level of the emission baseline, the total quantity of emission reductions, and the emission credit price. The examples examined in this study (i.e. a 10 MW wind farm, a 10 MW hydro project, and a 100 MW combined cycle natural gas plant) suggest that CER revenues can be expected to offset some of the plant costs. However, this offset is often rather a small share – especially at low carbon price levels – and this share would be reduced further once CDM-related transaction costs are taken into account.

- Predictability, economies of scale and up-dating: To provide greater predictability and to save baseline development costs, the combined margin baseline emission rate should be developed at the start of the project-based activity (i.e. ex-ante). Such a baseline emission rate could then be updated only periodically (and not annually) to save overall baseline development costs. Updates would not need to apply retroactively to projects already approved. However, to take advantage of possible economies of scale from a multi-project baseline and minimise updating costs for future projects, the data-set to calculate emission baselines should be publicly available. This presupposes at least some degree of public sector involvement, as private sector investors may not find it in their interest to let others free-ride on their own data collection efforts.

- Collaboration: Involving host-country experts in the development of the combined margin baseline was extremely useful to enable a faster identification of relevant information sources. Collaboration with local experts improves access to, and quality of data, and is likely to speed up the baseline development.

Given that perfection is impossible when the challenge is to estimate the unknown, the *combined margin* baseline methodology for grid-connected electricity projects seems to strike an appropriate balance between the need for environmental integrity, workable and transparent methodologies and low transaction costs. Although, some adjustments/modifications would still be needed to take into account some particular circumstances, once a baseline is established, it could be used consistently for multiple projects in a particular geographic setting over a several-year period.

Determining whether the *combined margin* baseline outcomes are “reasonable” in every case is a matter of judgement. Feedback from a wider stakeholder community would help with such an assessment. This approach does seem worthy of consideration by policy-makers involved in setting baseline rules for project-based mechanisms and/or credit based systems, such as the CDM Executive Board[41]. The *combined baseline* methodology could be a potential “default” baseline approach for project developers, and could also be a particularly useful reference for those involved in the validation and certification of emission reductions.

[41] According to the decisions taken at COP7 in 2001, the CDM Executive Board shall “approve new methodologies related to, *inter alia*, baselines,...”. It is also asked 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.” (FCCC/CP/2001/13/Add.2)

Annex I – Step-by-Step Calculation of Electricity Baseline

(from Bosi, 2000, *An Initial View on methodologies for Emission Baselines: Electricity Generation Case Study*, IEA/OECD Information Paper, Annex I.)

The calculation is based on the IPCC suggested methodology

- The first step is to calculate the electricity production of each individual plant/unit in the database:

(1) $$Electricity\ production\,(MWh)_z = Capacity(MW)_z * Load\,(hours\ of\ operation\ per\ year)_z$$

- It is then necessary to calculate the fuel consumption used to generate the electricity:

$$(2)\ Fuel\ consumption\,(GJ)_z = \frac{electricity\ production\,(MWh)_z}{efficiency_z} * 3.6$$

- The CO_2 emissions are then calculated using the IPCC default emission factor for each energy source and the IPCC suggested fraction of carbon oxidised:

(3)
$$CO_2\ emissions_z\,(GgCO_2) = \left[\frac{fuel\ cons._z(TJ) * emission\ factor_z\,(tC/TJ)}{1000} * fraction\ carbon\ oxidised_z\right] * \frac{44}{12}$$

The gigagrams of CO_2 emissions ($GgCO_2$) for each plant are then converted into tonnes of CO_2 emissions (tCO_2)

- The methane emissions (CH_4) for each plant are calculated using the IPCC default emission factors for each type of electricity generation technology:

(4) $$CH_4\ emissions_z\,(kgCH_4) = fuel\ cons_z\,(TJ) * emission\ factor_z\,(kg/TJ)$$

The kilograms of CH_4 emissions$_z$ (kg CH_4) for each plant need to be converted into CO_2 emissions equivalent (kt CO_2) by multiplying by the 100-year global warming potential of 23[42]. These CO_2 equivalent emissions then need to be translated into tonnes of CO_2 equivalent (tCO2).

- Total GHG emissions for each individual plant are calculating by adding the CO_2 emissions and the CH_4 emissions (translated into emissions CO_2 equivalent).

- The GHG emissions per unit of electricity output (in tCO_2/GWh) for each plant are obtained in the following way:

(5) $$GHG\ per\ unit\ of\ output\,(tCO_2/GWh)_z = \left[\frac{GHG\ emissions\,(tCO2)_z}{electricity\ output\,(GWh)_z}\right]$$

[42] IPCC, Third Assessment Report (2001)

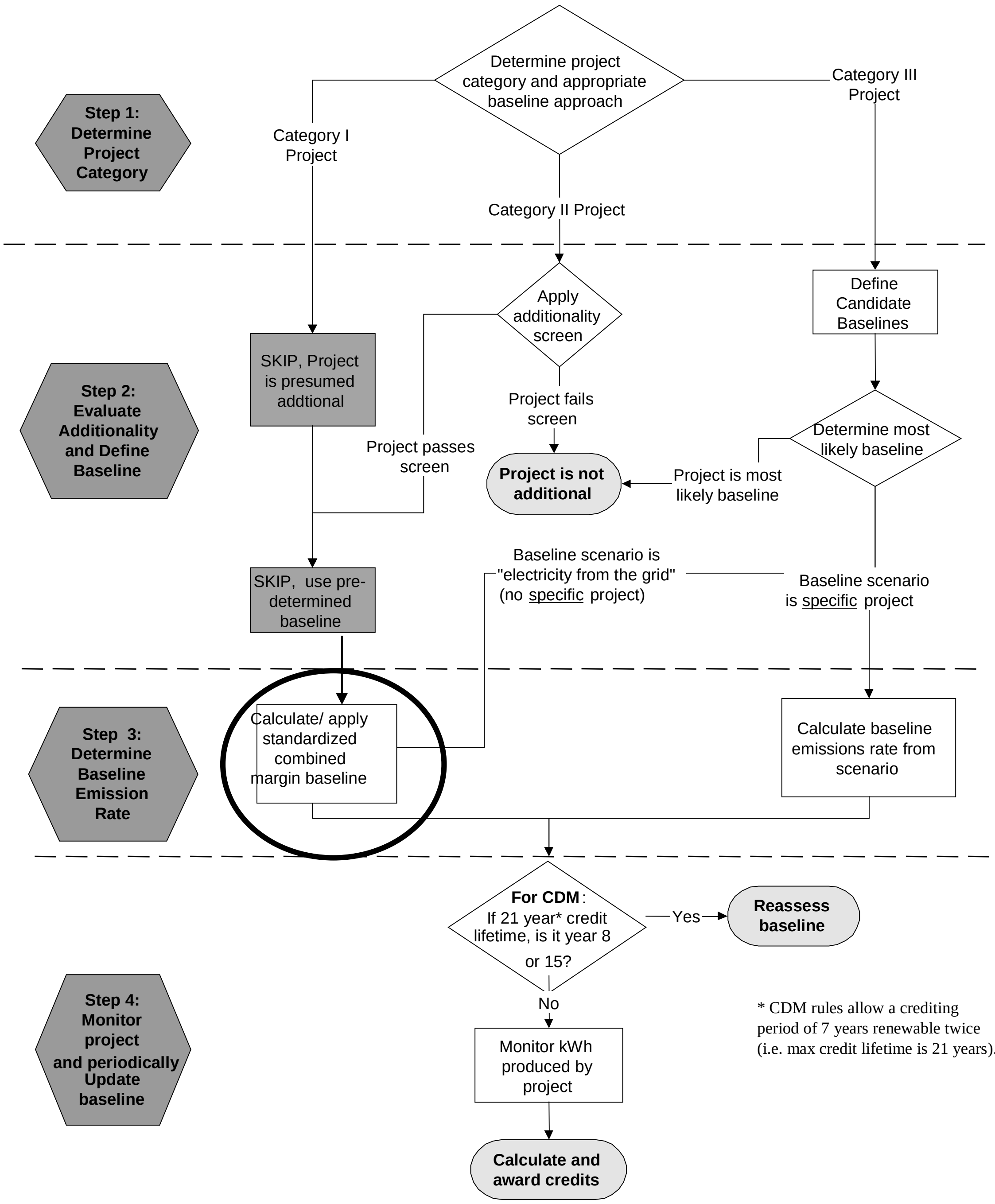
- The baseline is the sum of all the weighted average GHG emissions per unit of electricity production associated with each individual plant:

$$(6)\ Baseline\,(tCO_2/GWh) = \sum_{z=1}^{n} \left[\frac{GHG\ emissions_z}{\sum_{z=1}^{n} electricity\ production_z} \right]$$

Where:

- z represents each power plant in the database used to develop the electricity baseline.

Annex II – Overview of the Kartha et al. (2002) recommended baseline methodology



* CDM rules allow a crediting period of 7 years renewable twice (i.e. max credit lifetime is 21 years).

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Glossary

ANEEL	Agência Nacional de Energia Elétrica (Brazil's power regulatory agency)
Baseline emission rate	A baseline emission rate is a parameter, expressed in tCO2 per electricity generated (e.g. tCO2/GWh) for electricity projects. It is used to calculate the amount of emission reductions achieved by a project and thus the emission credits (e.g. CERs or ERUs).
Build margin (BM)	The build margin refers to new sources of electricity capacity expected to be built or otherwise added to the system, and affected by a new project-based activity. (Kartha et al. 2002)
Certified emission reduction (CER)	Under the Kyoto Protocol, CDM projects lead to certified emission reductions.
CDEC	Centro de Despacho Economico de Carga (Economic dispatch centre), Chile
Clean Development Mechanism (CDM)	Project-based mechanism resulting in emission credits (CERs) created under the Kyoto Protocol (Article 12) to assist developing (non-Annex I) countries in achieving sustainable development; and assist Annex I Parties in meeting their emissions commitments. CDM projects are implemented in non-Annex I countries and may involve private and/or public entities.
CNE	Comisión Nacional de Energía, Chile
Combined margin (CM)	A combined margin baseline reflects both operating and build margin effects. (Kartha et al. 2002)
GHG	Greenhouse gas
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change. The IPCC, created in 1998, assesses the scientific, technical and socio-economic information relevant for understanding human-induced climate change.
Load Factor	A measure of the utilisation of a generating facility. It is expressed in the percentage of energy produced by the facility compared with the energy it could have produced if operated continuously at maximum power.
Mt CO_2	Million tonnes of carbon dioxide
Megawatt (MW)	A unit of power (rate of energy consumption). One Megawatt is equal to 1,000 kilowatts or about 1,340 horsepower.
Megawatt hour (MWh)	A unit of energy consumption. One megawatt hour is the amount of energy consumed in one hour at a rate of one Megawatt.
NER	National Electricity Regulator, South Africa
OECD	Organisation for Economic Co-operation and Development
Operating margin (OM)	The operating margin refers to the changes in the operation of plants in an existing power system in response to a project-based activity (Kartha et al. 2002).

	OM-i, refers to the general operating margin calculation based on the weighted average of all plants in operation, excluding facilities that are both must-run and have zero fuel costs: hydro, geothermal, wind, low-cost biomass and solar. OM-ii refers to the operating margin calculation recommended in the case of hydro-rich countries. It is calculated by subtracting a fixed share (i.e. 50% of total generation) of hydro from the system average.
PCF	Prototype Carbon Fund: a private-public partnership operated by the World Bank
SIC	Sistema Interconnectado Central – one of Chile' electricity systems
SING	Sistema Interconectado del Norte Grande (SING) – one of Chile's electricity systems
TPES	Total primary energy supply