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COM/ENV/EPOC/IEA/SLT(2001)4

OECD ENVIRONMENT DIRECTORATE
AND
INTERNATIONAL ENERGY AGENCY

AN INITIAL VIEW ON METHODOLOGIES FOR EMISSION BASELINES: ELECTRICITY GENERATION CASE STUDY

INFORMATION PAPER

Organisation for Economic Co-operation and Development 2001
International Energy Agency
Organisation de Coopération et de Développement Economiques
Agence internationale de l'énergie

FOREWORD

This document was prepared in June 2000 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.

This case study is part of a larger analytical project undertaken by the Annex I Experts Group to evaluate emission baselines issues for project-based mechanisms in a variety of sectors. Additional work will seek to address further the issues raised in this and other case studies.

ACKNOWLEDGEMENTS

This paper was prepared by Martina Bosi of the IEA Secretariat. The author is grateful for comments and oversight from Jonathan Pershing, and advice from Olivier Appert, Maria Argiri, Pierre Audinet, Richard Baron, Laura Cozzi, Lawrence Metzroth, Hans Nilsson, John Paffenbarger, Bénédicte Riey, Karen Tréanton, Jocelyn Troussard, Kristi Varangu, and David Wallace (IEA), as well as comments and suggestions from Jan Corfee-Morlot , Jane Ellis and Thomas Martinsen (OECD). Shigemoto Kajihara (Japan), the U.S. delegation to the Annex I Expert Group and Robert Kleiburg of Shell International also provided very useful suggestions.

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ELECTRICITY GENERATION CASE STUDY

1. Executive Summary

The objective of this case study is to examine baseline methodologies in the context of the possibilities and implications of developing multi-project[1] or standardised baselines in the electricity generation sector. To do so, it considers, through a quantitative analysis using detailed electricity data, recent capacity additions in the electricity generation sectors of three countries with different national circumstances: Brazil, India and Morocco[2]. Compared to highly aggregated multi-project baselines (e.g. including all plants operating in a country), less aggregated multi-project baselines are likely to provide a better reflection of business-as-usual investments and thus be a more credible evaluation of what would happen without Clean Development Mechanism/Joint Implementation projects in the electricity sector.

The examination of multi-project baselines in the context of electricity generation projects is important and timely, as:

- Electrification is often linked to sustainable development priorities;
- The electricity sector is projected to grow significantly, particularly in non-OECD countries, during the next two decades;
- World CO_2 emissions from the electricity sector represent over one third of world annual energy-related CO_2 emissions and are projected to increase at an annual rate of 2.7% between 1995 and 2020 (IEA, 1998);
- Projections also indicate significant capital expenditures on new power plants in the non-Annex I region, which could potentially include CDM projects;
- The electricity sector seems particularly well-suited to the development of multi-project baselines; and,
- Electricity multi-project baselines would facilitate the calculation of the greenhouse gas (GHG) mitigation potential of other projects (*e.g.* energy efficiency projects).

[1] "Multi-project" baselines could be developed, for example, to assess, in a standardised manner, the emission reductions associated with similar electricity projects operating in similar circumstances. The advantages of developing these standardised baselines (as opposed to project-specific baselines) could include increased transparency and consistency, as well as the potential to reap economies of scale from the resources spent on the baseline-setting process.

[2] The three countries examined in the context of this case study are potential hosts of Clean Development Mechanism (CDM) projects. It is expected, however, that the issues and insights from this case study would also be applicable in the context of Joint Implementation (JI), although the application of its conclusions to Annex I Parties might warrant further examination.

The development of electricity multi-project baselines requires making decisions on certain key underlying assumptions. One of the first steps is to define the boundary of an electricity generation JI or CDM project. Although a fully comprehensive approach would argue for boundaries to include all life-cycle emissions related to electricity generation, this broad boundary definition is generally considered impractical for the development of CDM/JI emission baselines. It seems preferable, as demonstrated in this case study, to define the boundaries around the direct GHG emissions from the combustion of fossil fuels to generate electricity (which represent the bulk of life-cycle emissions associated with electricity generation).

The development of a multi-project baseline is necessarily based on either historical or projection data. There are inherent uncertainties associated with forecasts and projections, as well as discrepancies between projections and forecasts of different origins. Consequently, this case study constructs the multi-project baselines from historical data on recent investments in electricity plants/units, as well as on plants/unit under construction at the time of data collection. This choice of data set, which only considers recent plants, offers a good proxy for "what would occur without CDM/JI projects" in the electricity sector. However, baseline updates at regular intervals will be crucial to ensure that future projects are compared to multi-project baselines that credibly reflect the electricity generation situation at that time.

It is recommended to calculate multi-project baselines on a rate basis, *i.e.* tonnes of CO_2 emissions per GWh of electricity produced (instead of on total emissions, *e.g.* tCO_2). The total number of years for which a multi-project baseline will be considered adequate to reflect "what would occur otherwise" (*i.e.* the crediting lifetime) will be critical to determining the total amount of emission units that could be expected from a CDM or JI project in the electricity generation sector. Determining up-front the crediting lifetime associated with a multi-project baseline would also enhance transparency and consistency among similar types of projects, in addition to providing some certainty for the project sponsors (investors and host country).

There is no truly objective crediting lifetime for electricity multi-project baselines. Subjective assessments of what would be considered appropriate will need to be made. Various economic and technical factors/criteria (*e.g.* technical lifetime, economic lifetime of power plants, time required to pay off the debt, *etc.*) can be considered when making this assessment. However, these factors need to be balanced out with environmental considerations. This case study suggests a crediting lifetime for electricity multi-project baselines of around 10-15 years.

For example, this would mean that project developers could count on the same multi-project baseline for the agreed 10-15 year period. However, this does not necessarily mean that all future projects implemented in the subsequent 10-15 years would use that same baseline. In this context, it may be appropriate to consider periodically updating electricity multi-project baselines approximately every 5 years, for example, in order to reflect ongoing developments in the electricity sector.

The case study focuses on new electricity investments. Reliable data on timing of refurbishment or fuel switching of power plants is very scarce. However, estimates of economic lifetime frequently include normal refurbishments and updating of equipment. Nonetheless, some experts suggest that the multi-project baseline crediting lifetime be different for new projects and for refurbishment projects. This differentiation could be justified because the expected remaining lifetime of a plant being refurbished would normally be presumed to be shorter than the lifetime of a new power plant. Also, a distinction may be considered useful to take into account the difference in capital investments (which are typically lower for refurbishment projects) and thus the different size of incentive needed to stimulate more climate-friendly investments. However, some major refurbishments in the electricity sector can be quite capital intensive and come close to (or even match) investments for new power projects. Also, some refurbishment and greenfield electricity projects can have very similar greenhouse gas reduction benefits (*e.g.* fuel switching from coal to gas and a new gas plant). Thus, making a distinction between "refurbishment" and "greenfield" electricity projects may be difficult. Furthermore, it is important that both types of electricity projects be treated in a consistent manner in order to create a level playing field and avoid unwanted incentives in the electricity generation sector. This issue could usefully be explored further.

A crucial element to take into account in the development of multi-project baselines is the quality and availability of data. Ideally, the following plant-specific data:

- Commissioning date (in order to determine whether the plant/unit should be used in the sample of recent capacity additions);
- Type of technology (*e.g.* internal combustion engine, combined cycle gas turbine, *etc.*);
- Source of electricity generation (*e.g.* natural gas, water, bituminous coal, *etc.*);
- Generating capacity (measured in MW - it is a necessary input to calculate the electricity production in MWh);
- Load factor (for what portion of total possible hours in a year is the plant/unit in operation - this is necessary to determine the electricity production in MWh);
- Conversion efficiency (for fossil fuels);
- Emission factors (to convert into GHG emissions).

A lot of this data is available for each plant/unit (at least in the case of this case study)[3]. In circumstances where requisite information is not available, assumptions, based on expert advice from IEA secretariat and national experts, are used in lieu of actual data on these variables.

CO_2 emissions (calculated based on the type of fuel used by each plant) represent more than 99% of energy-related GHG emissions for electricity generation. Methane (CH_4) emissions are small and can be calculated based on the type of technology of each plant using IPCC default emission factors. Emissions of N_2O, also very small, were not estimated, as default emission factors are only available for few types of technologies. Robust multi-project baselines are likely to be possible without the inclusion of N_2O data.

Current data constraints need to be taken into account in decisions on baselines for electricity projects, but should not necessarily be considered a barrier. Independent assumptions, based on expert advice, can be made where data is not available. Moreover, the emergence of the CDM and JI mechanisms may stimulate the monitoring, reporting and publication of more detailed and reliable data.

This case study examines, quantitatively, various aggregation options to set multi-project baselines for electricity generation projects. Country-based multi-project baselines may be suitable in many countries. Multi-country baselines for groups of small neighbouring countries with similar circumstances may also be possible and useful. Similarly, large countries where regions are quite different may demand the development of sub-national multi-project baselines in order to be more credible.

[3] The plant samples used for this case study exclude CHP-type plants. Making conversion efficiency assumptions for CHP plants is complicated, as there is no standardised way of accounting for the production of both heat and power by these plants (for example, accounting for only the power produced by those plants would make them appear less efficient than they really are). Once appropriate conversion efficiency levels of CHP plants are developed, CHP plants could be included in the electricity generation baselines. The exclusion of CHP plants should not significantly affect the assessment and development of multi-project electricity baselines based on recent capacity additions, as CHP-type plants represented very small portions of recent capacity additions in the countries examined.

After having put in place a workable database, for any region or country being examined, assumptions or choices have to be made as to which electricity multi-project baseline would be most appropriate. This case study examines multi-project baselines based on recent capacity additions, according to: (i) all sources; (ii) only fossil fuels; (iii) source-specific; (iv) region-specific; and (v) load-specific. The implications of these baseline assumptions, in terms of stringency, vary from country to country. However, some general insights can be drawn from the case study:

- For Brazil and India, source-specific multi-project baselines (*e.g.* comparing different coal fired plants to a coal-specific baseline) yield the largest volume of emission credits from clean coal plants, *i.e.* coal-specific multi-project baselines lead to least stringent levels of any multi-project electricity baseline. Using such a baseline may not be considered, by some, as consistent with the environmental objective of the CDM. In fact, source-specific multi-project baselines, particularly in the case of coal, may cause concerns in terms of the overall environmental effectiveness of the project-based mechanisms. However, these baselines may be very useful in promoting a cleaner use of coal than would otherwise occur, which for countries like India and China, with huge coal reserves, could be an important variable in promoting a more environmentally benign electricity infrastructure.

Brazil may serve as an example of large countries with varied circumstances within their borders (a characteristic that also applies to India). In these cases, it may be appropriate to consider the further development of separate multi-project baselines for different regions within a country. At a minimum, the development of separate multi-project baselines for off-grid, isolated electricity systems would be useful.

- Developing separate multi-project baselines for peak and baseload electricity was done in the case of India, based on expert advice to make relevant assumptions. Given that the majority of recent plants are assumed to generate baseload electricity, the multi-project baseline for baseload electricity is very similar to the country’s multi-project baseline using all sources. However, the multi-project baseline for peaking electricity is quite a bit higher, due to the typically lower efficiency of the gas and oil-fuelled power plants generating peak electricity. Developing a separate multi-project baseline for peaking electricity may be desirable, as those plants are typically different from baseload plants. However, caution is needed in making assumptions on which plant type would constitute the “peaking electricity generation” for a given country and preferably would only be done with advice from in-country experts.

This case study provides a series of quantitative examples (Figures 6, 7 and 8 in particular) of the implications on stringency of different electricity multi-project baselines in the context of Brazil, India and Morocco.

- The evaluation of “stringency” based on “average” performance depends on what exactly the “average” represents. For example, there is a significant difference between multi-project baselines based on the average emission rate of recent capacity additions including all sources and multi-project baselines based on the average emission rate of recent fossil fuel capacity additions. In this case study, using Brazil as the example, the latter would lead to a baseline of 808 tCO_2/GWh, while the former would lead to a baseline of 108 tCO_2/GWh. The “average emission rate” of recent capacity additions including all sources may be viewed as sufficiently stringent in some cases or perhaps too stringent in others (*e.g.* Brazil where recent capacity additions consist largely of non-GHG emitting hydropower plants). Nonetheless, it may be worth considering further the potential options and implications for better than average electricity multi-project baselines. For example, a better than average multi-project baseline could be defined as x% below the average multi-project baseline using recent capacity additions (including all sources). Other potential options may be to define it as better than the 75th percentile, for instance, or setting the baseline at one or two standard deviations below the average emission rate.

- However stringent a multi-project baseline for electricity generation projects is, non-emitting sources would always be below the baseline level and therefore theoretically eligible to generate emissions credits. This is irrespective of whether they are part of the business-as-usual trend in that country's electricity generation sector. It might thus be useful to consider a "hybrid" approach to assessing the GHG additionality of those zero-emitting projects. For example, it may be worth considering an activity additionality test, which would screen out projects or types of power plants that have a significant probability of generating non-additional emission credits. In order to focus on larger plants that have the potential to lead to larger volumes of non-additional emission credits, another option would be to require large zero-emitting projects to go through a more elaborate evaluation process. Small renewable projects would only need to pass the multi-project baseline test.

The details of the overall CDM decision-making process have yet to be agreed-upon by the international community. However, the final decision on which multi-project baseline(s) is/are most appropriate and at what level of stringency, can be expected to be a decision tailored to national circumstances, based on environmental, economic, administrative and data availability criteria. Further consideration might be warranted to determine whether and, if so, what type of guidance could be developed internationally to ensure consistency among similar projects in similar circumstances.

This case study considers the potential volume and value of emission credits that could be earned by a hypothetical new best available technology (BAT) gas plant in India and how they could affect the economic feasibility of the project. In the example examined, the revenues from the emission credits (calculated at both 5 US$/t$CO_2$ and 10 US$/t$CO_2$) would help increase the potential revenues from the hypothetical new BAT gas plant, but would not be sufficient to make it economically feasible. At a 5% discount rate, the CDM credits contribute to reducing the net deficit of the hypothetical new Indian gas plant by 16% if emission credits are worth 10 US$/t$CO_2$.

The evaluation of the contribution of the emission credits from a potential CDM project critically depends on the assumptions made (*e.g.* cost and revenues of the project, type of financing, discount rate, *etc.*). Another key factor, which cannot be generalised, is each investor's financial criteria (*e.g.* rate of return). It is thus not possible to draw general conclusions on the potential volume of projects under different multi-project baseline options. However, if the example of this case study can be representative of projects more broadly, the CDM impact on investment decisions could be relatively small: proposed CDM projects may need to be already very close to meeting the basic feasibility criteria from an investor's point of view in order for the emission credits to have an impact on the investment decision. In this case, the CDM could be viewed as a means of improving the ranking of the proposed project against other competing investment options.

2. Context

Options for Project Emission Baselines (Ellis and Bosi 1999) included case study simulations with multi-project baselines in the electricity generation sector. These multi-project baselines for Brazil and India were derived from 1996 national electricity generation (including all existing capacity) and CO_2 emissions data. That case study demonstrated, *inter alia,* that the environmental stringency of a multi-project baseline is dependent on assumptions used and independent of baseline approach, *i.e.* multi-project, hybrid or project-specific. The case study also illustrated the significance of different national circumstances in a determination of the absolute level of the baseline and the resulting amount of emission credits that might accrue from its use.

Ellis and Bosi (1999) also acknowledged that alternative multi-project sectoral baselines could be appropriate in different regions or countries. For example, the construction of multi-project baselines in the electricity generation sector might be based on the emissions performance of recently constructed plants. Compared to highly aggregated multi-project baselines (*e.g.* including all plants operating in a country), less aggregated multi-project baselines are likely to provide a better reflection of business-as-usual investments in that sector and thus be a more credible evaluation of what would happen without CDM/JI projects.

The case study presented here builds on this earlier work and further examines baseline methodologies in the context of the possibilities and implications of developing multi-project or standardised baselines in the electricity generation sector. To do so, it considers recent capacity additions in the electricity generation sectors of three countries with different national circumstances: Brazil, India and Morocco[4]. This case study also draws on a number of studies, including the findings of Tellus Institute *et. al.* (1999), which includes a very useful analysis of baselines in the electricity generation sector.

[4] The three countries examined in this case study are potential hosts of CDM projects. It is expected, however, that the issues and insights from this case study would also be applicable in a JI context, although it may warrant further examination.

3. Broad Overview of Sector

The electricity generation sector provides key services (*e.g.* lighting, heating, power) that maintain and enhance countries' economic activity, as well as maintain and increase populations' standards of living.

Reliable supply of electric power is a key input for the industrialisation process of developing countries' economies. In many developing countries, the growth rate of this sector is higher than that of the overall economy, as electrification is often closely linked to development priorities (*e.g.* in Brazil and India).

The 1998 World Energy Outlook (IEA 1998a) projected an annual growth rate of 3.0% from 1995 to 2020 for world electricity generation. The non-OECD share of world electricity generation is projected to increase from 40% in 1995 to 53% in 2020. Non-Annex I generating plant capacity is expected to roughly double in 2010, compared to 1995 and nearly triple by 2020, representing an addition of about 1500 GW of new capacity in this time-frame[5]. According to IEA (1998a) projections, by 2020, this translates into US$1699 billion (1990 prices) in capital expenditure on new generating plants in the non-Annex I region. World CO_2 emissions from the power generation sector represent over one third of world annual energy-related CO_2 emissions and are projected to increase at an annual rate of 2.7% between 1995 and 2020. Although coal is projected to maintain its position as the most widely used source for electricity generation, natural gas-generated electricity grows at the highest rate during the projection period (*i.e.* up to 2020). The use of renewables in electricity generation is projected to increase but it is expected to remain a relatively small portion of total generation throughout the period.

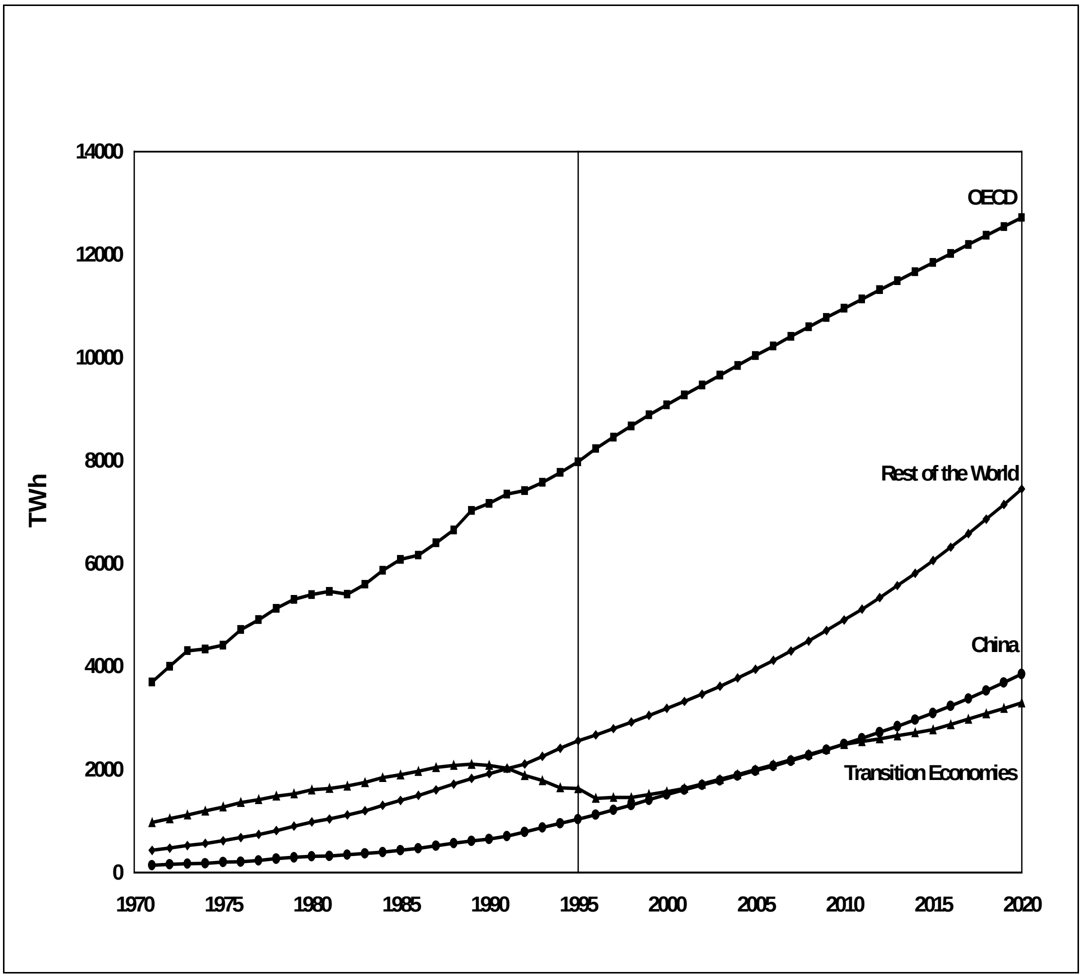
Notwithstanding the different fuel or energy sources (*e.g.* coal, oil, hydro, *etc.*), electricity output is considered homogeneous. One kWh of electricity provides the same service[6] (*e.g.* lighting, heating, *etc.*) everywhere in the world. In a given country or region, the fuel or energy source used for electricity generation depends on factors such as the availability and proximity to the fuel or energy supply, reliability, prices of fuel and technology, as well as government policies. Electricity imports may also play a significant role in a country's electricity supply. National circumstances (including resource endowments and distance between the resource and the consumption centres) help explain differences between countries' electricity generation - and large countries with diverse geographic territories and more than one electricity grid may also have different electricity generation mixes between regions. Many utilities within different countries rely on a mix of generating plant types in order to hedge against fluctuations in the prices of fuels and uncertain growth rates in electricity demand, as well as to match changing load requirements (*i.e.* peak versus baseload).

[5] *i.e.* an increase from 832 GW in 1995, to 1592 GW in 2010 and to 2387 GW in 2020.

[6] Assuming equipment/appliances have same efficiency levels.

Figure 1(a)

World electricity generation by region



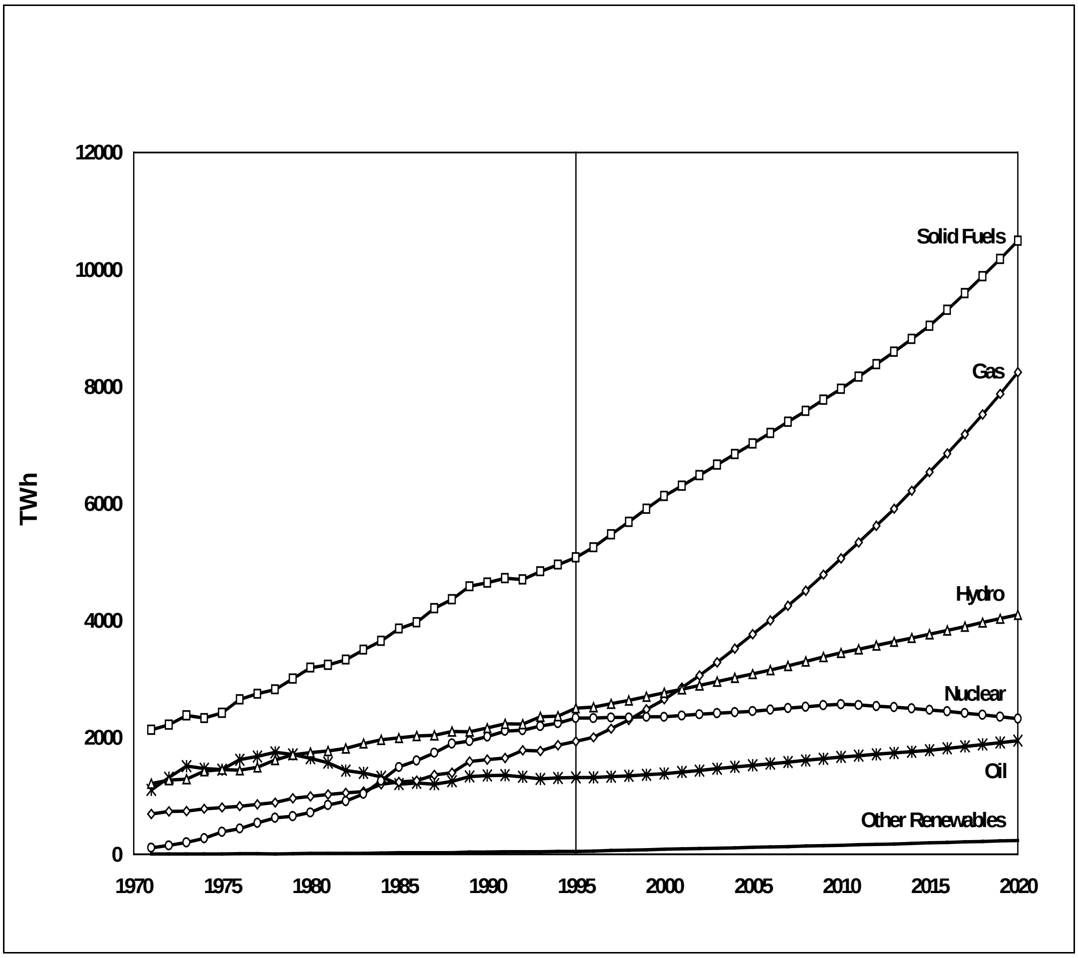
Source: IEA, 1998a

Different power production technologies, combined with different inputs, result in different greenhouse gas (GHG) emissions by unit of electricity output. The different energy sources used to generate electric power, as well as the type of technology along with their conversion efficiency levels, are key factors in determining the GHG emissions associated with power generation. Hydroelectric, wind and nuclear plants, for example will not emit any GHG emissions while generating electricity with technologies using fossil fuels (*i.e.* coal, oil and natural gas) can result in significant GHG emissions[7].

[7] While the electricity generation from these sources are essentially non-emitting, life cycle analyses indicate none have "zero" emissions. For example, land inundation in hydro-power reservoirs releases methane, while processing uranium is often undertaken with fossil fuels.

Figure 1(b)

World electricity generation by fuel



Source: IEA, 1998a.

Several AIJ projects were based in the electricity generation sector, although most did not seek to use standardised methodologies to set emissions baselines. In terms of JI/CDM potential, the power sector is viewed by many as a good candidate to host projects. Tellus (1999) concludes: "the power sector is likely to be fertile territory for CDM projects as well as being relatively well-suited to benchmarks".[8] A Pew Center report (Pew Center, 1999) also concludes that there is a significant potential for emission reduction in the power sector: "if developing countries adopt different policies and planning methods for their power generation sectors, technologies other than those included in "business-as-usual (BAU)" projections could provide lower local and global environmental impacts and produce similar or even higher economic benefits".

A number of different types of electricity projects, in the context of CDM and JI, could be undertaken. For example (IEA, 2000 forthcoming):

[8] The term "benchmark" used in some studies on baselines is equivalent to "multi-project baselines", which is the term used in this case study to describe emissions baselines that can apply to more than one project.

(i) Installing a new plant (*i.e.* greenfield);

(ii) retiring an existing plant and replacing it with a new one;

(iii) fuel switching (*e.g.* from coal to gas) that may require minor or major replacement of equipment;

(iv) refurbishment of equipment at existing facilities (*e.g.* replacing existing basic generation technologies, such as boiler or turbine, with a more recent technology); or

(v) housekeeping type projects (*e.g.* improvements to processes, *etc.* that do not involve installing generation equipment).

This case study is based on data from new plants and is most likely applicable to the types of electricity projects (i) to (iv).

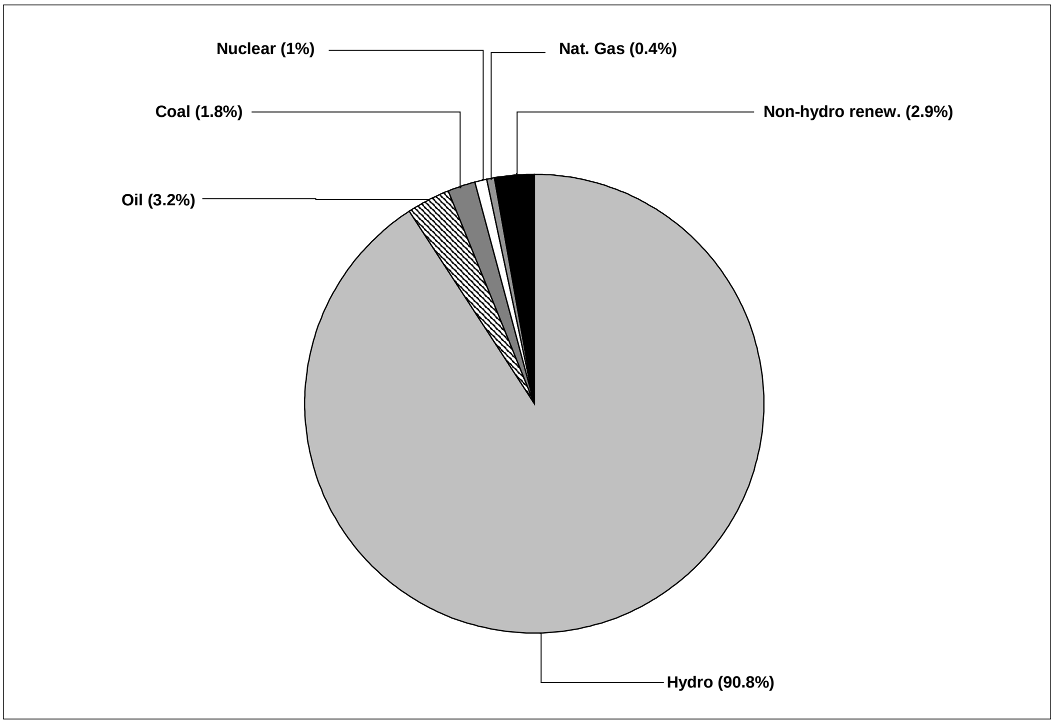
3.1 Brazilian electricity context

Electricity generation totalled 307.3 TWh in 1997 (IEA, 1999a) in Brazil. The growth rate of Brazilian electricity consumption (4.7% p.a. between 1990 and 1997) is greater than the country's GDP growth rate (3.1% p.a. during the same period). The predominant source of electricity generation is hydro, generating 90.8% of total electricity in 1997. The other sources include oil (3.2%), non-hydro renewables (2.9%), coal (1.8%), nuclear (1%) and natural gas (0.4%). However, Brazil's predominant reliance on hydro is expected to slowly decrease (although remaining the main source of power), as the competitivity 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. Brazilian authorities are thus planning a thermoelectric transition program to help meet increasing electricity demand. The Brazilian Ten-Year Expansion Plan: 1999-2008 is counting on increased involvement of the private sector in the electricity sector to develop the hydropower potential in parallel with the construction of new thermal plants. This thermoelectric expansion should be fundamentally based on the use of natural gas, mineral coal and, in the case of isolated electricity systems, petroleum derivatives (Electrobrás *et. al.*, 1999). The expansion of the nuclear program remains within the public sector, which plans to have two additional nuclear units (Angra II[9] and Angra III) come on stream by 2005.

[9] Angra II was under construction at the time of producing the Ten-Year Expansion Plan 1999-2008.

Figure 2

Total electricity generation in Brazil (all existing capacity in 1997): 307.3 TWh



Source: IEA (1999a)

Significant natural gas reserves in South America (*e.g.* in nearby Bolivia) and plans to construct pipeline infrastructure in South America that would go into Brazil make it likely that natural gas will be readily available and competitive for some of the new power facilities. Thus, the current very low percentage of Brazilian electricity generated by natural gas can be expected to increase. The extent and rate of this increase is difficult to predict, however, as it will largely depend on private sector investment (as opposed to government plans).

3.2 Indian electricity context

Electricity consumption in India is also growing (7% p.a. between 1990 and 1997) faster than economic activity (5.5% p.a. during the same period); it has more than doubled in the last 10 years. According to IEA statistics (IEA, 1999b), Indian electricity generation in 1997 totalled 463 TWh.

The lack of an inter-connected electricity grid across the country means that states with surplus power do not transfer that surplus to states facing power shortages. Furthermore, the Indian distribution and transmission system is under significant strain due to fluctuations in frequency and voltage. This combined with the poor quality of the transmission lines, result to power losses amounting to approximately one fifth of generated electricity.

The electricity sector attracted more than a sixth of all Indian investments over the past decade (Shukla *et. al*., 1999). Despite these investments in power addition, the power generating supply is still insufficient to meet electricity demand in India. Increasing the proportion of the population connected to the electricity grid is one of the development goals of the Indian government. In its Ninth Five-Year Plan (1997-2002)

(Government of India, 1997), the Indian government evaluates that the capacity addition requirement during the 1997-2002 period to be about 46,814 MW, but assesses that a capacity addition of the order of 40,245 MW would be feasible during the Plan period.

India is a very large and populated country with significant regional differences within its borders (*e.g.* in resource endowments, electricity demand, *etc.*). It has large reserves of coal and was the world's third largest coal producer in 1998. On the other hand, India has few oil or gas reserves, although the share of gas in India's total primary energy supply is growing quickly (from 2.8% in 1990 to almost 4% in 1997) and gas use in power generation is projected to grow significantly (IEA, 2000). Using domestic coal for electricity generation is generally cheaper than using imported fuels due to high tariffs and volume import restrictions. It is, therefore, not surprising that coal-fired electricity generates the great majority (73% in 1997) of Indian electricity. However, recent developments, such as reduced restrictions on fuel imports, inadequate expansion of coal mining capacity, as well as greater foreign investments, have resulted in an increase in the use of natural gas for power generation. Lower capital costs, shorter construction periods and reduced environmental impacts also benefited natural gas plant construction. Over the last 25-30 years, the capacity share of large hydro has declined, while nuclear power capacity is growing slowly (with the aim of using India's significant thorium resources). The contribution of non-hydro renewables is relatively small, but increasing in specific markets and in certain regions of the country (mainly Tamil Nadu and near Mumbai (Bombay) along the Southern coasts). India's Ninth Five-Year Plan (1997-2002) includes a target of 3000 MW for non-hydro renewable capacity.

3.3 Moroccan electricity context

According to IEA statistics (1999b), Morocco's electricity output totalled 13.1 TWh in 1997, with 45% coming from coal, 39% from oil and 16% from hydro. Approximately half of Morocco's population lives in rural areas where basic services, including electricity, are scarce. The Government is putting in place an ambitious plan to raise the electrification rate in rural areas from 21% in 1994 to 60% in 2003 (Resource Publications (PTY) Ltd., 1999).

The country has some coal reserves in the north-east which are mostly used for electricity generation (Royaume du Maroc, 1998), but still has to import significant amounts of coal and oil for its electricity generation. Coal and hydroelectricity[10] production is encouraged. The Moroccan government is also examining the feasibility of building, with private sector involvement, a large combined cycle power station using imported natural gas from neighbouring Algeria. In addition, the Government is encouraging the development of renewable energy in the form of wind and solar electricity. While solar is being considered mainly for remote villages not connected to the nation-wide network (in the context of Morocco's rural electrification program), Moroccan authorities are planning to connect wind power generation to the national electricity grid (Resource Publications (PTY) Ltd., 1999). Morocco is also conducting a feasibility study on the use of biomass fuelled electricity generation based on energy crops or agricultural residues.

[10] The hydro potential is estimated at 5 billion kWh, but only 40% was being exploited in 1998 (Ibid).

4. Baseline Construction: Environmental Performance

This section examines key issues for the construction of electricity multi-project baselines.

4.1 Key underlying assumptions

The development of electricity multi-project baselines requires making a number of assumptions/choices on the parameters to be used. Assumptions on boundaries, data sets, baseline lifetime and the technology and fuel are examined below.

4.1.1 Boundaries

In order to take into account the complete GHG impacts associated with a particular electricity generation project, it would be necessary to set boundaries around a project in a way that would include all life-cycle emissions related to the project. For example, emissions associated with the extraction of gas, coal or oil from the ground, or with the production of biomass fuels, emissions released during the transportation and emissions generated during the transmission of electricity should all be within the full life-cycle boundaries of an electricity generation project[11].

However, this type of broad project boundary definition is generally viewed as impractical for the development of CDM/JI emissions baselines. For example, in the case of electricity generated with imported fuels, the current international emission inventory guidelines allocates the emissions from the extraction of these fuels to the producing country and not to the importing country. In fact, the Tellus (1999) report points out that “full fuel-cycle analysis is neither straightforward nor simple and could result in double-counting if CDM projects occur at more than one point in the fuel chain”. Information is not available, however, to be able to determine whether the greater risk is that of double-counting or that of leakage from full-life cycle emissions that would not be accounted for in the baseline calculation. This issue may require further analysis.

A more practical option appears to be to define the project boundary around the direct emissions associated with electricity generation. In essence, this would mean establishing the project boundaries to include only the GHG emissions from the combustion of fossil fuels, which is where the bulk of GHG emissions come from, as indicated in Table 1 below. This would be the case even in a full life-cycle analysis of GHG emissions associated with the generation of electricity using different fossil fuels (European Commission, 1995).

This approach is also favoured in the Oeko-Institut (2000) report, which concludes, “… it seems preferable that life-cycle emission should not be included in the baseline estimate”. JIRC (2000) states that one of the lessons learned from the Dutch AIJ experience is that system boundaries should be determined clearly and that the common policy was “not to credit the project with extra emission reductions realised outside and beyond the control of the project”, also suggesting that the boundaries should be set around the direct emissions of an electricity generation project.

[11] More information on life-cycle emissions of various energy technologies can be found in the IEA Greenhouse Gas Implementing Agreements. Furthermore, the European Commission (Directorate-General XII, Science , Research and Development) produced a series of studies under the title Externe: Externalities of Energy (1995), providing useful information on the assessment of externalities and life-cycle analysis associated with energy.

Table 1: Relative importance of Greenhouse Gases

Type of GHG	CO_2	CH_4	N_2O	Others	Σ
Shares in Total anthropogenic GHG	82%	12%	4%	2%	100%
Contribution of Energy Sector	96%	35%	26%	n/a.	85%
Main Source within Energy Sector	Fuel Combustion	Fugitive emissions	Fuel Combustion	n/a.	

Source: UNFCCC, Second compilation and synthesis of second national communications, FCCC/CP/1998/11/Add.1, September 1998

Direct greenhouse gas emission from the combustion of fossil fuels to generate electricity are carbon dioxide (CO_2), which represent the bulk of the direct GHG emissions (more than 99%) and relatively small amounts of methane (CH_4) and nitrous oxide (N_2O). As IPCC default emission factors for N_2O are not available for most types of electricity generation plants, the quantitative examples of multi-project emission baselines presented in this case study are based on a narrow boundary around direct CO_2 and CH_4 emissions associated with electricity generation of the different plants/units[12].

4.1.2 Historical or projection data

There are different views on the utility of data based on projections as a basis for developing multi-project baselines. For example, Hagler Bailly (1998) recognises the relevance of using newer units to develop “marginal benchmarks”, but notes that in the case of countries that need new capacity (such as developing countries), it may be appropriate to develop a forward-looking multi-project baseline, or to incorporate an efficiency trend from the historical data. However, developing an efficiency trend can be relatively subjective, as it is difficult to predict how and at what rate technologies that are at different stages of development will increase their efficiencies. Furthermore, government policy, which can also influence developments in the electricity sector, cannot be considered static and may stimulate changes over time, which throw forecasts off. For example, policy decisions working to increase market liberalisation of countries’ electricity sectors can significantly change developments compared to a previous situation dominated by state-owned monopoly utilities.

Tellus (1999) concludes that projections of power sector behaviour are very sensitive to underlying assumptions; they therefore prefer to use historical performance data (on recent capacity additions) for developing multi-project baselines. Similarly, Ellis and Bosi (1999) note that while projections may be viewed as a better reflection of what would happen under a future business-as-usual (BAU) scenario than baselines based on historical data, projections’ inherent speculative nature may make them more open to gaming than baselines constructed using historical data.

[12] Further examination of the boundary issue in the case of emissions from electricity generation could be useful; for example, exploring the possibilities and implications of accounting for indirect GHG emissions occurring outside the defined boundary.

Because of the inherent uncertainty associated with forecasts and projections and the discrepancies between projections or forecasts by different groups, this case study proposes to construct baselines from historical data on recent investments in electricity units, as well as on units currently under construction. Tellus (1999) notes that an averaging period of 3 to 5 years appears adequate for the construction of baselines based on recent capacity additions in the electricity sector. CCAP (2000) suggests that a multi-project baseline for new projects may represent the average emission rate of new plants during the last 5 to 10 years. This case study defines "recent investments" (or capacity additions) as those plants or units that began operating in 1995 or later, as well as those plants that were under construction at the time of collecting the data (*i.e.* 1998-1999). The use of disaggregated and recent data should enable the construction of credible emission baselines reflecting what would likely occur without the CDM/JI in individual countries.

However, as discussed in the following section, the updating of multi-project baselines at regular intervals will be important to ensure that developments in the electricity sector are being captured for the assessment of future projects. For example, although Brazil's electricity generation via natural gas[13] can be expected to increase (although it is difficult to project the importance of this), it's potential future trend is not captured by the data used for this case study. Baseline updates will thus be crucial to reflect this trend as it occurs and to ensure that future electricity projects continue to be compared to a credible baseline.

4.1.3 Lifetime

Crediting lifetime

The calculation of potential emission baselines for projects in the electricity generation sector in this case study is based on tCO_2/GWh per year. The total number of years for which a multi-project baseline will be considered adequate to reflect "what would occur otherwise" (*i.e.* crediting lifetime) will be key to determining the total amount of emission units that could be expected from a CDM or JI project in the electricity generation sector. Determining up-front the crediting lifetime associated with a multi-project baseline would also enhance transparency and consistency among similar types of projects, in addition to providing some certainty for the project sponsors (investors and host country). A recent Dutch study on baselines (JIRC, 2000) suggests considering the development of a generic list of time horizons based on the type of projects; the electricity generation projects could be one "type" of project and the lifetime for this type could differ from that of forestry projects, for example.

The AIJ Pilot Phase includes several electricity generation projects. The proposed lifetime over which these projects are expected to generate GHG reduction benefits is generally long[14], but there is no consistency between the AIJ projects[15]. For example:

- the Dutch hydro power project in Bhutan has a 10 year lifetime (based on the economic lifetime of the project);

[13] Eletronorte, an electric energy utility which belongs to the Brazil's Eletrobras System, notes on its website (www.eln.gov/br/home35.htm) recent studies' findings that natural gas may be "the most convenient fuel source for the thermal units both technically and economically to substitute the diesel consumption due to the large gas reserves available in the Amazonas State". Consequently, although they are continuing to plan that their capacity additions will be using diesel oil, they expect that these new plants will fuel switch to gas sometime in the future.

[14] Justifications for the timelines used for AIJ projects are not always provided in the reports (www.unfccc/program/aij).

[15] See Ellis (1999) for greater discussion on the different timelines used in the AIJ pilot phase.

- the Doña Julia hydroelectric project in Costa Rica uses a project lifetime of 15 years (with possible 5 year extensions);
- the US solar-based rural electrification project in Honduras is based on an "estimated service life" of 20 years;
- the US Bio-Gen biomass power project in Honduras is based on its expected operational lifetime of 20 years;
- the fuel-switching Decin project[16] in the Czech republic uses a project lifetime of 26 years;
- the Australian Fiji Grid Connected Photovoltaic project estimates CO_2 reductions over 20 years (*i.e.* the technical lifetime of the equipment);
- the German Latvia windpark project uses a 10 year lifetime (consistent with length of the depreciation period);
- the Costa Rican Aeronergia Wind Project calculates emission reduction benefits over 4 years (to take into account Costa Rica's policy goal to phase out fossil fuels by 2001).

Seeking to set objective crediting timelines for electricity baselines is challenging. There are various criteria/factors that can be considered, for example:

- technical lifetime of electricity project equipment;
- economic lifetime of power plants;
- the time needed to pay off the debt;
- the depreciation period.

There is no one set of generic technical lifetime data for power plants. The design lifetime of major components of power plants tend to be around 30 years, but in many cases the economic lifetime of power plants may be longer depending on the maintenance and prevailing economic conditions. For example, the NEA/IEA (1998) study used a common economic lifetime of 40 years for new state of the art baseload power plants (*i.e.* coal, gas and nuclear plants) in its reference cases. However, the Oeko-Institut (2000) Report notes the uncertainty on whether a manufacturer's recommended technical lifetime would be valid for all countries, given that the technical lifetime typically depends on various factors such as maintenance and climatic influences. Nonetheless, the report concludes, based on the technical literature on lifetime estimates for biomass power plants, that 15 years seemed like a "realistic choice" for the technical lifetime of wood waste power plants in Zimbabwe.

Indian experts[17] have suggested using 20-40 years for the technical lifetime of different types of power plants in India, with 20 years viewed as appropriate for internal combustion (reciprocating engine or diesel engine) plants; 25 years for wind turbine generators and gas/combustion turbines; 30 years for steam turbines (boilers), nuclear plants and gas turbines in combined cycle; and 40 years for hydro plants.

Brazilian experts[18] have suggested using 15 to 50 years for the technical lifetime of different types of power plants in Brazil, with 15 years for gas turbines, 15 years for internal combustion engine plants, 25

[16] This is a CHP-type plant.

[17] Recommendations received (March, 2000) from experts of the Indian Institute of Management, Ahmedabad, India.

[18] Recommendations received (April, 2000) from experts of the Agência Nacional de Energia Eléctrica (Aneel), Brasília, Brazil.

years for steam turbines, combustion turbines, gas turbines in combined cycle and nuclear plants, 30 years for wind turbine generators and 50 years for hydro plants.

Recent IEA work has examined the issue of capital stock turnover (IEA, 2000 forthcoming). Although the focus of this work is on capital turnover in OECD countries and thus may not provide an accurate picture of the situation in countries with economies in transition and developing countries, it may nonetheless offer interesting insights for the crediting lifetime of emission baselines for JI/CDM electricity projects. The IEA forthcoming report indicates that one estimate for the lifetime of power plants can be the economic useful life for accounting purposes[19]. According to UNIPEDE information (1993), the economic useful lives for new thermal power plants (*i.e.* that burn fuel directly to produce steam) range from 15 to 40 years and from 16 to 30 years for nuclear plants. The median economic useful life for these two types of new power plants is 25 years. (This is within the technical lifetime ranges estimated by the Brazilian and Indian experts above.)

Statistics exist in some OECD countries on the age of their power plants. For instance, the average retirement age for all types of power plants in the US is about 38 years[20] and the median retirement age of coal-fired plants in the European Union was around 34 years. However, these figures do not tell the whole story and are likely to be underestimated. In the case of the US, plants that were retired tended to be relatively small; while the older but larger plants continue to operate with ongoing maintenance. In the case of the EU, the figure obtained for the retirement age was largely influenced by the early retirement of coal fired plants in the UK, due to a combination of environmental requirements and changed market conditions. In fact, the report notes that large coal-fired power plants could continue to operate almost indefinitely on relatively modest maintenance schedules. Furthermore, the lifetime of components[21] (*e.g.* turbines, boiler piping and superstructure and steam pipes) may also surpass the average retirement age of smaller older plants. There is not sufficient experience with combined-cycle gas turbines (CCGTs) to assess the typical lifetime of this technology. It is expected, however, that the main CCGT component that would require refurbishment would be the turbine blades, but some manufacturers believe that this should not be prior to 11 years of operation (IEA, 2000 forthcoming).

In addition to purely technical factors, increased competition in the electricity sector (through privatisation and deregulation of electricity markets, as is currently being experienced in many OECD countries) can be, in some cases, an incentive to extend the lifetime of power plants. In fact, the extension of plant lifetime may involve lower capital risks than investing in a new power plant. The ongoing electricity market reform of OECD countries may not be entirely relevant for developing countries: while the former have significant over-capacity, the latter are rather suffering from under-capacity (as mentioned in section 3).

Turning to economic and financial considerations, the depreciation period is not the same for all electricity projects and varies by country. The time needed to pay off the debt depends on the financing of the project (*e.g.* bonds, bank loans, or equity) and profitability. In general, 10 to 15 years is the maximum time for private bank loans, whereas corporate bonds can have a length of 15 to 30 years and government loans can be for 20 to 30 years. However, Oeko-Institut (2000) points out that, in some cases, particularly in some developing countries, commercial loans are not always available for particular projects[22]. Consequently,

[19] In some countries, this reflects the depreciation period that national tax authorities allow utilities to apply to their capital stock.

[20] This figure, based on the US Energy Information Administration database, includes average retirement ages of 58 years for hydro plants, 38-45 years for steam turbines (depending on fuel used), 31-33 years for internal combustion engine generators and 21 years for nuclear power plants.

[21] Many power plant components deteriorate very slowly under baseload operation.

[22] This is also true for countries with economies in transition.

the "typical" payback time of loans used for a project may not be appropriate to determine the crediting lifetime associated with a baseline.

The crediting lifetime for multi-project electricity baselines has to take into account the need to provide project investors with sufficient certainty on the number of years for which they can take into account revenue flow from emission credits and to create an incentive to invest in more climate-friendly power projects. However, some (*e.g.* CCAP, 2000) argue that this is shorter than the typical lifetime of power project investments. Given that the electricity generation sector in each country is not static, it is also important, from an environmental perspective, to be somewhat conservative, in the creation of emission credits in order to ensure lasting climate change benefits.

This discussion and analysis is mostly focussed on new electricity investments. Reliable data on timing of refurbishment or fuel switching of power plants is very scarce. However, estimates of economic lifetime frequently include normal refurbishments and updating of equipment.

Some experts have suggested that the crediting lifetime be different for new projects and for refurbishment projects. For example, the Dutch program recommends 5 years for good-housekeeping projects, 10 years for refurbishment/retrofit projects and 15 years for greenfield projects and no distinction is made between projects in different sectors. However, others (*e.g.* CCAP submission to UNFCCC, January 2000) indicate that the crediting lifetime could vary by project type and/or by sector.

One of the rationales for having different crediting lifetimes associated with baselines for refurbishment and greenfield projects is that the expected remaining lifetime of a power plant being refurbished would normally be presumed to be shorter than the lifetime of a new greenfield plant. Making a distinction may also be considered useful to take into account the difference in capital investments (which is typically lower for refurbishment projects) and thus the different size of incentive needed to stimulate more climate-friendly investments. However, some major refurbishments in the electricity sector can be quite capital incentive and come close (or even match) investments for new power projects. Also, some refurbishment and new electricity projects can have very similar greenhouse gas reduction benefits (*e.g.* fuel switching from coal to gas and a new gas plant). Thus, while some electricity projects may be easily labelled "greenfield" or "refurbishment", it may be difficult for others (*e.g.* the replacement of turbines and fuel switching at an existing plant can be considered very similar to installing a new plant). This means that if a distinction were to be made between "refurbishment" and "greenfield" electricity projects, it would need to be specifically defined.

It may be necessary to further explore the options and implications of distinguishing between refurbishment and new projects in terms of the baseline crediting lifetime[23]. However, given that this case study is based on data of new recent capacity additions as a proxy for "what would occur otherwise" in the electricity sector of different countries, this distinction is not made here.

Based on the various studies examined and different criteria and objectives, the international community may wish to consider the possibility of setting a crediting lifetime for electricity generation baselines around 10 to 15 years. This is less than the typical lifetime of electricity plants, but it would nonetheless ensure that revenues from emission credits could accrue during the first years of the project, when it is most important to pay off debts. From an environmental perspective, this timeframe is likely to provide sufficient certainty in the decision-making process of project developers and investors, for consideration of greater climate-friendly projects, while still being environmentally cautious by not extending the current

[23] The treatment of "good house-keeping" projects in the electricity sector would also need to be examined further.

assessment of "what would occur otherwise" too far into the future[24]. It may also be considered important to stay relatively close to the planning horizon of the UNFCCC negotiations: commitments are currently only specified until 2012, but the Kyoto Protocol specifies that negotiations on commitments for subsequent commitment periods shall start no later than 2005.

Using a baseline fixed for 10-15 years would mean that at the start of the electricity project, project developers would know that they could count on using the same multi-project baseline for the agreed crediting timeline. However, this does not necessarily mean that all future electricity projects implemented in the subsequent 10-15 years would also use that same multi-project baseline.

Timing of baseline updates

Setting a baseline crediting timeline up-front is expected to provide greater certainty to project developers and also potentially stimulate earlier climate change investments, particularly if it is expected that the multi-project baseline will be updated (perhaps more stringently) in the future for subsequent projects.

Regardless of the crediting timeline chosen, multi-project baselines are likely to need regular updates for future electricity projects, particularly if key factors become sufficiently important to improve GHG intensity of electricity generation. For example, Tellus (1999) mentions factors such as advances in combustion technology and increased competition in power markets that would require updating multi-project baselines if they are to continue to provide an adequate representation of "what would occur otherwise". Other potential factors could include effects of reforms of energy sector policy and changes in investment conditions in potential CDM/JI host countries.

It may be desirable, as a starting point, to consider periodically updating electricity multi-project baselines, *e.g.* every five years. This would mean, for example, that electricity projects implemented more than 5 years after the development of the first set of electricity multi-project baselines would be assessed against updated multi-project baselines, as the first set of electricity baselines would be considered as having expired. Five-year intervals appear reasonable in seeking to strike a balance between, on the one hand, seeking to reflect business-as-usual developments in countries' electricity sectors over time (particularly if baselines are developed with historical data, as in this case study) and, on the other, managing the overall baseline development costs (through updates at a reasonable frequency).

4.1.4 Technology and fuel

The technology (and its conversion efficiency) of a plant/unit and its source of electricity (*e.g.* coal, wind, oil, *etc.*) are the two key variables determining the GHG-intensity of electricity production. These variables depend on various factors, such as resource endowments, price of fuels, access to technologies, infrastructure, maintenance, *etc.* in a given country or region.

The database used in this case study to develop multi-project baselines based on recent capacity additions includes information on the fuel used by each individual unit, as well as the type of plant. However, assumptions, based on different sources and expert advice, had to be made for the conversion efficiency of each type of technology. Ideally, it would have been better to produce conversion efficiency assumptions for each individual plant/unit in the sample used for the case study. However, this type of detailed information was not possible to develop here. Instead, country-specific assumptions were made for the

[24] From an environmental perspective, it may be useful to further examine the potential trade-off between (i) more or less stringent baseline levels; and (ii) longer or shorter baseline crediting lifetimes.

different types of technologies. For the purpose of this study, it is thus assumed that all plants using the same technology in a given country have the same conversion efficiency[25] (see Annex C).

4.2 Data needs, quality and availability

Establishing multi-project baselines for power generation based on national average performance figures using all existing electricity generation capacity can be quite straightforward[26], as data are available for more than 100 countries[27]. For example, for all three countries examined in this case study, it is possible to draw national sectoral baselines for power generation with 1997 data (Annex D includes examples of such baselines, using all existing capacity, based on weighted average for all sources or weighted average for fossil fuel only).

Although simple to draw (and a useful basis for comparison), this national multi-project baseline design may not be considered, in many cases, the best way of reflecting "what would occur otherwise" in the power sector, as:

- Capital investments in the power sector have a relatively long lifetime (see section on *Lifetime* for more details), but the type of new investments and fuel mix tends to change over time. Consequently, a national baseline based on a country's entire power generation capacity in a given year (*e.g.* 1997) can include 30-year old plants that would not be at all representative of typical investments made in more recent years.
- Some larger countries have very different electricity generation mixes, reflecting sub-national differences in availability and cost of sources for power generation within their borders. As a result, a single national electricity generation multi-project baseline may not be considered appropriate to reflect some (potentially significant) regional differences in both total existing generating capacity as well as more recent power investments.

There is, therefore, a strong rationale to try and develop a more disaggregated multi-project baseline for the power sector. As pointed out in Tellus (1999), a multi-project baseline based on recent capacity additions provides a more accurate estimate of what would occur without a JI or CDM electricity project than does a multi-project baseline based on all existing capacity. Of course, the trade-off is that the analytical work to support multi-project baseline estimation based on recent additions requires more data gathering and time to prepare.

In this case study, the sample of plants used to develop multi-project baselines based on recent capacity additions consisted of power plants/units in Brazil, India and Morocco that started operating in 1995 or later, or that are currently under construction.

The development of electricity multi-project baselines based on recent capacity additions, as developed in this case study, requires plant specific data on those recent plants/units included in the sample used to calculate the multi-project baseline:

[25] Seeking plant level data or making disaggregated assumptions for conversion efficiencies of different plants within a country would improve the accuracy of the multi-project baselines.

[26] This does not imply that the collection of information needed to develop this data is a simple exercise.

[27] See, for example, annual IEA statistics on Energy Balances of Non-OECD Countries and CO_2 Emissions from Fuel Combustion.

1. Commissioning year (in order to determine whether the plant/unit should be used in the sample of recent capacity additions).
2. Type of technology (*e.g.* internal combustion engine, combined cycle gas turbine, *etc.*);
3. Energy source used for electricity generation (*e.g.* natural gas, water, bituminous coal, *etc.*);
4. Generating capacity (measured in MW - it is a necessary input to calculate the electricity production in MWh);
5. Load factor (what portion of total possible hours in a year is the plant/unit in operation - this is necessary to determine the electricity production in MWh);
6. Conversion efficiency (for fossil fuels);
7. Emission factor(s) of energy source(s) used (to convert into GHG emissions).

Some of this data, at least for the countries examined in this case study, is readily available for each plant/unit, while some is not, which means that some estimates or assumptions need to be made.

The data for this case study is drawn from the Utility Data Institute (UDI)/McGraw-Hill (1999) *World Electric Power Plants Data Base*. This data base includes information on individual electric power plants world-wide, except for two types of power plants: (i) most reciprocating engines or gas turbines identified in primary sources as “emergency”, “standby”, or “back-up”; and (ii) all gas turbines or internal combustion engines on offshore platforms. Due to the difficulty in data collection, the UDI database may not necessarily include, for all countries, fully comprehensive coverage for all wind turbines, internal combustion engines and mini-and micro-hydro units. Although the coverage may not be comprehensive for some countries, it is nonetheless considered representative[28].

The UDI/McGraw-Hill (1999) database includes, albeit with a small lag (1 to 2 years), information on the electricity source, capacity, technology and on-line date for each unit[29]. The database, however, does not include information on the conversion efficiency and load factors for the different types of plants. Assumptions, based on IEA expert advice (and subsequently checked with experts from Brazil and India), were made for these two key variables.

It was not possible to develop reasonable load and efficiency assumptions for CHP-type (combined heat and power) plants, as literature on this type of information, particularly for Brazil and India, is quite scarce[30]). So, the plant samples used for this case study exclude CHP-type plants. Nonetheless, this omission, due to unavailable data and the difficulty in making reasonable assumptions[31], should not significantly affect the development of multi-project electricity baselines based on recent capacity additions. In fact, CHP-type plants which started operating after 1994 or are currently under construction (UDI/McGraw-Hill database) represented, in the case of Brazil, only 3.8% (*i.e.* 9 plants) of the total number of plants in the Brazilian sample and 0.9% (*i.e.* 169.5 MW) of the total capacity originally considered for this case study. In the case of India, twenty-three CHP-type plants were taken out of the

[28] Information based on personal communication with Chris Bergesen of McGraw Hill (March, 2000).

[29] There were a few “unknown” or “unspecified” values for certain key variables for some plants in the database. This required additional research by the author in order to determine the correct data or to make realistic assumptions.

[30] There are no CHP-type plants in the Moroccan database used for this case study.

[31] Making conversion efficiency assumptions for CHP plants is complicated, as there is no standardised way of accounting for the production of both heat and power by these plants (for example, accounting for only the power produced by those plants would make them appear less efficient than they really are). Once appropriate conversion efficiency levels of CHP plants are developed, CHP plants could be included in the electricity generation baselines.

case study sample, but they represented only 598 MW (*i.e.* 1.7% of total electricity capacity originally considered for the multi-project baseline based on recent capacity additions).

In the end, this case study's multi-project baseline analysis on recent electricity capacity additions is based on[32]:

- 229 power plants/units representing a generating capacity of 19,040 MW in Brazil (out of a total of 1070 existing plants/unit representing 82,287 MW of generating capacity in Brazil);
- 13 power plants/units representing a generating capacity of 1,452 MW in Morocco (out of a total of 94 existing plants/unit representing 4,709 MW of generating capacity in Morocco); and
- 617 power plants/units representing a generating capacity of 35,770 MW in India (out of a total of 2,441 existing plants/unit representing 125,951 MW of generating capacity in India).

The CO_2 (calculated based on the type of fuel used by each plant) and the CH_4 emissions (calculated based on the type of technology of each plant) associated with the production of electricity can be easily estimated using IPCC default emission factors. 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) were not estimated, as default emission factors are only available for few types of technologies.

The multi-project baselines are based on rates (*i.e.* tCO_2/GWh), as suggested in various studies[33], instead of on total emissions (*e.g.* tCO_2).

4.3 Aggregation

The literature surveyed in this work generally examines emissions baselines for electricity generation in individual countries and not worldwide. For example, the electricity case study simulations in Ellis and Bosi (1999) highlighted the potential significance of differing national circumstances (*e.g.* resource endowments) on GHG emissions associated with electricity generation. Tellus (1999) points out to the absence of a clear/consistent worldwide trend in the electricity sector and also concludes that multi-project baselines based on individual countries' circumstances might therefore be most appropriate. This suggests that there is some acceptance that developing emission baselines on a country basis is appropriate. Of course, this would not preclude the possibility of developing baselines on a multi-country basis for a group of small neighbouring countries with similar circumstances. Similarly, large countries where regions are quite different may demand the development of sub-country multi-project baselines in order to accurately reflect "what would occur otherwise".

This case study examines various options, with quantitative comparisons, to set country-based multi-project baselines for electricity generation projects.

4.4 Baseline calculation

Developing a national-type of baseline using nationally aggregated data derived from all existing electricity capacity (Ellis and Bosi, 1999), for example, is a relatively straightforward exercise. For a given country and for the latest year for which data are available (*e.g.* 1997), it consists of summing the weighted average CO_2 emission contribution (per unit of electricity production) of each source of electricity:

[32] See Annex II for more details on the data sample used for this case study.

[33] Ellis and Bosi (1999), Hagler Bailly (1998) and Tellus *et. al.* (1999).

Equation 1:

$$CO_2 \text{ per unit of production} = \sum_{i=1}^{n} \left[\frac{CO_2 \text{ emissions}_i}{\sum_{i-1}^{n} \text{electricit y production}_i} \right]$$

Where: *i* represents each electricity source (*e.g.* coal hydro, nuclear, natural gas) used in the country;

- CO_2 Emissions for electricity source "i" are measured in tonnes of CO_2 (*e.g.* this data is available in CO_2 Emissions from Fuel Combustion reports published yearly by the IEA);
- Electricity production by electricity source "ï" is all the electricity produced, measured in GWh, in a given country in a given year by the energy source (*e.g.* this data is available in The Energy Balances of Non-OECD Countries reports[34] published yearly by the IEA).

Developing a more disaggregated multi-project emission baseline for electricity generation based on recent capacity additions, as is the focus of this case study, requires more detailed data and more elaborate calculations. The multi-project baseline (measured in tGHG (*i.e.* tCO_2-equivalent)/GWh) using recent capacity additions is calculated by summing up the weighted average GHG contribution by unit of electricity generation of each recent plant:

Equation 2:

$$GHG \text{ emissions per unit of production} = \sum_{z=1}^{n} \left[\frac{GHG \text{ emissions}_z}{\sum_{z=1}^{n} \text{electricit y producti on}_z} \right]$$

Where: *z* represents each individual electricity plant/unit in the database;

- GHG emissions for each plant/unit "z" are measured in tCO_2-equivalent (with disaggregated information, it is possible to calculate CH_4 emissions, as well as CO_2 emissions, using IPCC methodologies and default factors);
- Electricity production for each recent plant/unit "z" is measured in GWh.

Unlike equation (1) based on nationally-aggregated data for a given year where CO_2 emissions and electricity production (GWh) figures are readily available, equation (2)'s electricity output (GWh) and GHG emissions have to be calculated. Data (GWh and GHG emissions) are not generally readily available at such a disaggregated level; they had to be estimated in this case study. Annex I contains information on the individual steps that were taken, in this case study, to calculate disaggregated multi-project electricity baselines based on recent capacity additions.

[34] Similar data also exists for OECD countries in separate IEA reports.

5. Potential Baseline Assumptions

5.1 National average GHG performance (per unit of output) of all existing electricity capacity

Emission baselines based on national average 1997 GHG performance per GWh of all existing plants, either including all sources or only fossil fuels, are presented in Annex D. In the case of all three countries examined in this case study, there is a significant difference between national multi-project baselines based on all existing capacity using all sources and only fossil fuel sources for the same country. Moreover, each country's different national circumstances lead to significant variances between countries' baseline emission levels.

While baselines based on all existing capacity are easy to develop and provide an interesting basis of comparison, the case was made earlier that they do not provide a satisfactory representation of the business-as-usual electricity situation. The focus of the rest of the analysis will thus be on baselines based on recent capacity additions.

5.2 National average GHG Performance (per unit of output) of recent capacity additions (after 1994)

As was the case for multi-project baselines based on all existing national capacity (above), there are significant variances between the three countries when examining baselines based on recent capacity additions. It is interesting to note that calculating multi-project baselines using recent electricity capacity additions provides a different picture, compared to the baseline calculation based on total existing capacity, for all three countries examined in this case study[35]. The trends, however, do not all move in the same direction: in some cases, recent capacity additions are towards more GHG-intensive electricity generation; while in others, the recent trend is towards less GHG-intensive electricity generation, confirming that there is no global consistency in the development of electricity generation capacity. Thus, a country-focussed approach to establishing multi-project baselines in the electricity sector appears warranted.

Different designs of multi-project baselines based on recent capacity additions are examined for each of the three countries. The final decision on which multi-project baseline(s) is/are most appropriate and at what stringency level can be expected to be a political decision based on environmental, economic, administrative and data availability criteria. The analysis below examines various designs of multi-project baselines that could be considered in such a decision-making process. Electricity projects that lead to emissions below the baseline level are assumed, in this case study, to be "additional to what would occur otherwise" and could thus generate emission credits.

The analysis starts by looking at multi-project baselines based on recent capacity additions[36] using (i) all sources, as well as (ii) recent fossil fuel-based capacity additions (See Annex E for details). Other types of

[35] Care has to taken when comparing the baselines calculated using the two types of data: all existing electricity capacity and recent electricity capacity additions, as the data sources (IEA and UDI/McGraw-Hill) are different. One other difference, albeit small, may stem from the fact that, in this case study, recent baselines from UDI/McGraw-Hill data include CH_4 as well as CO_2 emissions, while the IEA data is based only on CO_2. However, given that CH_4 emissions are so small in comparison to CO_2 emissions from fuel combustion, the fact that one baseline includes CH_4 while the other does not, is not expected to be the cause of any significant variance between the two baselines.

[36] CHP-type plants were excluded from the sample due to difficulty in finding consistent assumptions for load and efficiency factors.

baseline disaggregation are also examined subsequently: (iii) source-specific baselines; (iv) sub-country (regional) baselines; (v) peaking and baseload baselines.

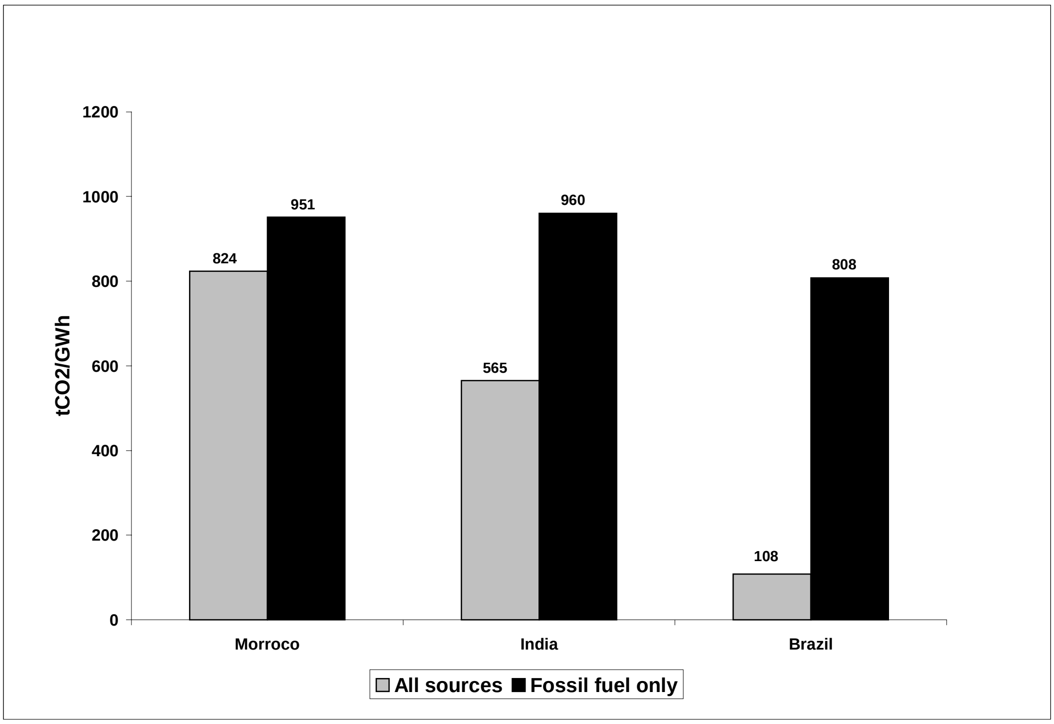
5.2.1 Multi-project baselines using recent capacity additions: all sources and only fossil fuels

Figure 3 presents weighted average baselines based on the emissions (tonnes of CO_2 equivalent) per electricity production (GWh) of each plant.

The variances between the countries' multi-project baselines are much greater for the recent capacities including all sources than for the recent capacities including only fossil fuels. Given that plant-level data for conversion efficiency and load factors were not available and that only country-specific assumptions could be made, it is possible that, in reality, variances between countries' multi-project baseline levels would be larger than those calculated, but this cannot be verified.

Figure 3

Multi-project baselines using recent capacity additions: All sources and fossil fuel only



Brazil

A Brazilian national baseline based on recent capacity additions (including all sources) is equal to a weighted average of 108 tCO_2/GWh (the emissions of the different plants included in the sample range from 0 tCO_2/GWh for the hydro, nuclear and non-hydro renewable plants to 953 tCO_2/GWh for steam turbine plants using bituminous coal). A comparison of this baseline with a national baseline using all existing electricity capacity in 1997, which is equal to 49 tCO_2/GWh[37], highlights the recent Brazilian trend of electricity investments being made, in larger proportions than historical investments, in fossil fuel power

[37] From IEA (1999a); includes only emissions of carbon dioxide.

plants. Although the baseline based on recent capacity additions is 47% greater than the one based on all existing capacity, only non-emitting electricity projects could generate emission credits under the recent capacity additions including all sources baseline. All other electricity projects would generate emission levels greater than the 108 tCO_2/GWh baseline. This means that electricity generated by natural gas, which is foreseen to increase in Brazil in the near future, would not "pass" this baseline test even if it were best-available-technology (BAT) that might not otherwise be installed.

For Brazil, a multi-project baseline based on recent fossil fuel capacity additions, which represent 11% of the sample's total recent capacity, would be equal to 808 tCO_2/GWh (this is about 11% lower than a similar baseline based on all fossil fuel existing capacity in 1997, but almost eight times greater than a multi-project baseline based on recent capacity including all sources). Brazil's fossil-fuelled electricity generation is thus experiencing a trend towards a lower GHG-emitting mix. Obviously, a greater volume of projects that generate credits can be expected under a "recent fossil fuel capacity additions" multi-project baseline, than under a "recent all sources capacity additions" multi-project baseline. However, since the majority of recent capacity additions are expected to continue to be hydro-based, using a multi-project baseline based on recent fossil fuel capacity additions may not be considered a credible baseline, at least in the short-term.

India

A national Indian multi-project baseline based on recent capacity additions including all sources would be equal to 565 tCO_2/GWh (which is 38% lower than the same baseline using all 1997 existing capacity in India). Such a baseline is thus a clear reflection of the improvements in GHG intensity of recent investments in power plants in India. Under this multi-project baseline based on recent capacity additions including all sources, natural gas plants would be the only fossil fuel plants being able to generate emissions below the emission baseline and thus be able to generate emission credits.

An Indian multi-project baseline based on fossil fuel recent capacity additions amounts to 960 tCO_2/GWh (*i.e.* 14% lower than the same baseline using all 1997 existing power generating capacity in India). The power plants included in this baseline represent 48% of the total recent capacity included in the Indian sample.

Morocco

Morocco's baseline based on the weighted average of recent electricity capacity additions, including all sources, amounts to 824 tCO_2/GWh, which is almost 11% greater than the same baseline using all 1997 existing capacity. A Moroccan baseline based on recent fossil fuel capacity additions, which represent 73% of Morocco's total recent capacity, equals to 951 tCO_2/GWh (28% higher than the same baseline calculated using all 1997 existing capacity). This suggests that the business-as-usual investments, inasmuch as they can be approximated by the recent capacity additions used in this case study, are actually increasing the GHG-intensity of Morocco's electricity generation compared to historical power investments.

5.2.2 Multi-project baselines using recent capacity additions: source-specific

Another potential way to establish multi-project baselines may be to set them according to the source of electricity generation of recent capacity additions. Tellus (1999) concludes that disaggregated multi-project baselines, according to fuel or technology, could help reduce the potential likelihood of free rider projects. On the other hand, source-specific multi-project baselines would not encourage fuel switching for electricity generation, which may be, in many cases, the most desirable electricity generation option from a greenhouse gas mitigation point of view.

The calculated values (in tCO_2/GWh) for source-specific multi-project baselines based on recent capacity additions for Brazil, India and Morocco are presented in Table 2 below. These can be compared to values for estimated Best Available Technology, based on performance averages from OECD countries:

Table 2: Multi-project baselines based on recent capacity additions: Source-specific

	Brazil (tCO_2/GWh)	**India (tCO_2/GWh)**	**Morocco (tCO_2/GWh)**	**Best available technology* (tCO_2/GWh)**
Coal	954	1,085	954	781-786**
Oil	761	661	791	Not available
Natural Gas	426	418	None	382
Other electricity sources	0.0	0.0	0.0	0.0

*Best Available Technology (BAT) values are taken from the Case Study Simulations with Multi-Project Baselines in Ellis and Bosi (1999), based on NEA/IEA (1998).
**The higher value is for India and the lower value is for Brazil. (Ellis and Bosi (1999) did not include multi-project baseline simulations for Morocco).

Source-specific multi-project electricity baselines, as defined in Table 2, would mean that projects in the form of best-available technology coal power plants could generate 299 emission credits per GWh (assuming one credit equals 1 tCO_2 reduced below the baseline level) in India and 173 credits/GWh in Brazil and Morocco[38]. However, projects in the form of best available technology (BAT) gas plants would generate a slightly larger volume of emissions credits (*i.e.* 44 emission credits) in Brazil than in India (36 emission credits). As hydro, nuclear and non-hydro renewables do not generate GHG emissions, electricity projects based on these sources would need another basis of comparison (one suggestion on how to potentially deal with this situation is a “hybrid” approach discussed in section 6).

Table 3 compares these results with the emission credits that could be generated by the same BAT projects. This could be done by using baselines drawn up using the performance of source-specific capacity additions and the performance of a weighted average for recently installed fossil plants.

[38] Assuming the performance of BAT would be the same in Morocco as estimated for Brazil.

Table 3: Potential emission credits (per GWh) generated by projects in BAT coal and BAT gas under different multi-project electricity baselines based on recent capacity additions

	Brazil Baseline :			**India Baseline:**		
	all sources	***fossil fuels only***	***source-specific***	***all sources***	***fossil fuels only***	***source-specific***
BAT Coal Plant	0	27	173 (coal)	0	174	299 (coal)
BAT Gas Plant	0	426	44 (gas)	183	578	36 (gas)

According to the calculations presented in Table 3, projects in BAT coal generation would not generate emission credits in either Brazil, or India if the multi-project baseline was based on recent capacity additions including all sources. Compared to that same multi-project baseline (*i.e.* all sources), BAT gas projects would not generate emission credits in Brazil, but would generate 183 emission credits per GWh in India. It is also worth noting that if multi-project baselines were source-specific, clean coal (BAT) plants in both India and Brazil could generate a significantly larger volume of emission credits than BAT gas plants, even though the latter plants emit substantially lower levels of GHG emissions than the former. In fact, in both Brazil and India, it is under source-specific multi-project baselines that clean coal plants could generate the largest volume of emission credits. This outcome may not be considered by some as consistent with the environmental objective of the CDM. In fact, source-specific multi-project baselines, particularly in the case of coal, may cause concerns in terms of the overall effectiveness of the CDM, although they may promote a cleaner use of coal - which for countries like India and China, with huge coal reserves, could be an important variable in promoting a more environmentally-benign electricity infrastructure and lead to GHG emission levels lower than would otherwise occur.

5.2.3 Multi-project baselines using recent capacity additions: sub-national

For large countries with different circumstances within their borders and different power grids based in these different regions, multi-project baselines in the electricity sector may need to be disaggregated below the country-level in order to provide a credible representation of "what would have happened otherwise". This is likely to be the case for countries such as India and Brazil. For countries such as Morocco, *i.e.* a relatively small country with a small number of recent electricity capacity additions, it is probably not necessary to develop sub-national electricity baselines.

However, developing disaggregated baselines on a sub-national basis can increase the data needs and time required to develop the baselines, as databases do not always specify which electricity system is associated to each individual plant. In this case study, implications of such disaggregation is presented for Brazil, where the Brazilian Electricity System is divided into three separate subsystems[39]:

(i) The South/Southeast/Midwest Interconnected System;

(ii) The North/Northeast Interconnected System; and

[39] Source: Petrobras and the Brazilian Ministry of Mines and Energy (1999).

(iii) The Isolated Systems (which represent 300 locations that are electrically isolated from the interconnected systems)[40].

In order to examine the potential implications of setting sub-national multi-project baselines, this case study includes emission baselines developed for these three main Brazilian electricity systems. The Isolated Systems in this case study are represented by those systems in the Northern Region (*i.e.* Amazonas, Roraima, Randônia, Amapá and Acre States) which represent approximately 85% of the Isolated Systems[41] (this region is thus referred to as "North Isolated" system in this case study).

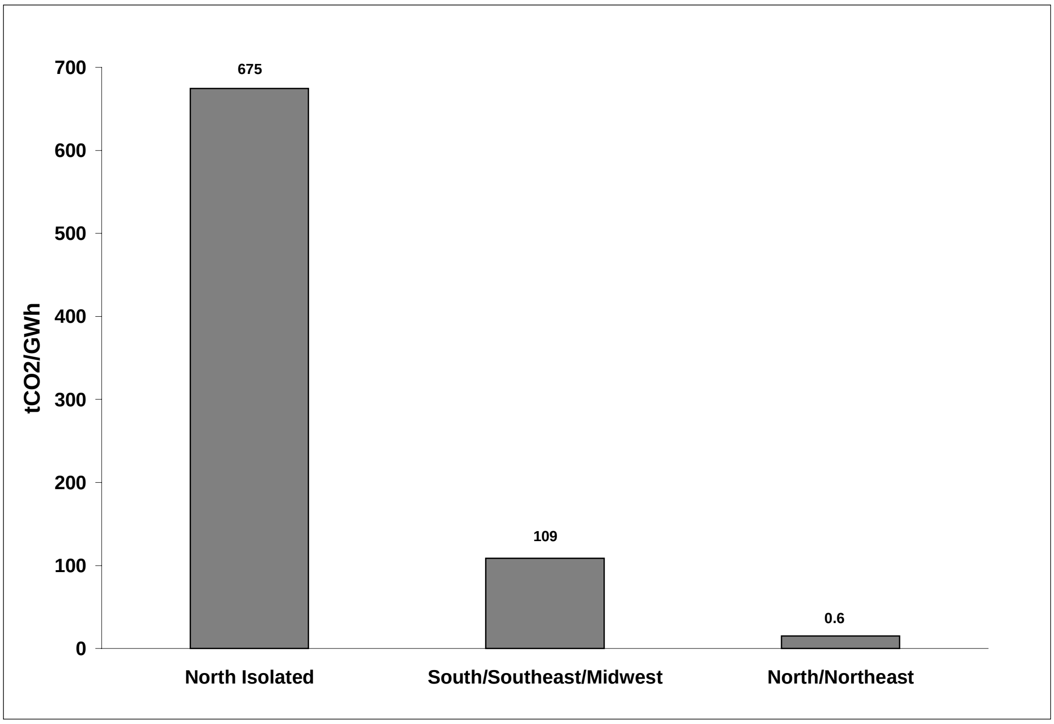
Table F-1 of Annex F indicates quite clearly the detailed differences that exist, in terms of electricity generation, between the three Brazilian systems. Figure 4 below presents the variances between Brazil's three sub-national baselines (including all sources). Unlike the other two systems that use mainly hydro, the smaller North Isolated system is based almost exclusively on oil-fired (diesel) electricity, translating into a higher multi-project baseline level. This means that a single Brazilian baseline based on total recent capacity additions (of all regions) does not provide a very accurate reflection of the situation in the Isolated Systems.

[40] In these isolated systems, about 50% of the locations have a daily supply period of less than 24 hours and rationing still persists (Ibid).

[41] As the database used for this case study did not specify the electricity system which was associated to each individual plant, it was not possible to determine exactly which system plants in other states belonged.

Figure 4

Multi-project baselines using recent capacity additions: Brazil's regions (all sources)



In fact, according to the data used for this case study and the breakdown made between the three regions[42], multi-project baselines using all sources would be equal to 675 tCO_2/GWh for the North Isolated system (representing 3% of Brazil's electricity generation by recent capacity additions), 0.6 tCO_2/GWh for the North/Northeast system (17% of Brazil's electricity generation by recent capacity additions) and to 109 for the large South/Southeast/Midwest system (accounting for 80% of Brazil's electricity generation by recent capacity additions). It is not surprising, therefore, that as the latter system is where the bulk of Brazil's electricity capacity and demand is concentrated, it is practically identical to the national Brazilian baseline using recent capacity additions including all sources.

As Brazil can be shown as an example for other large countries with different circumstances within their borders (*e.g.* India[43]), it may be appropriate to consider further the development of separate multi-project baselines for different regions within a country. At a minimum, the development of separate multi-project baselines for off-grid, isolated electricity systems would be useful.

[42] The allocation of each individual plant to one of the three main electricity systems in Brazil may not be completely accurate.

[43] More time and information would be needed to develop region-specific electricity multi-project baselines for India, but there are no *a priori* reasons why it could not be possible.

5.2.4 Multi-project baselines using recent capacity additions: load-specific

Tellus (1999) concludes that while aggregated electricity multi-project baselines could provide desirable incentives for switching to lower or non-emitting sources, disaggregated approaches to multi-project baselines could be more effective. Also, in considering disaggregation possibilities examined above, the authors believe that another interesting option may be to distinguish between baseload and peakload plants. This disaggregation might be particularly useful to create incentives to improve the efficiency of peaking units which are typically less efficient than baseload units. It may also be useful for the assessment of GHG reductions from certain energy efficiency projects.

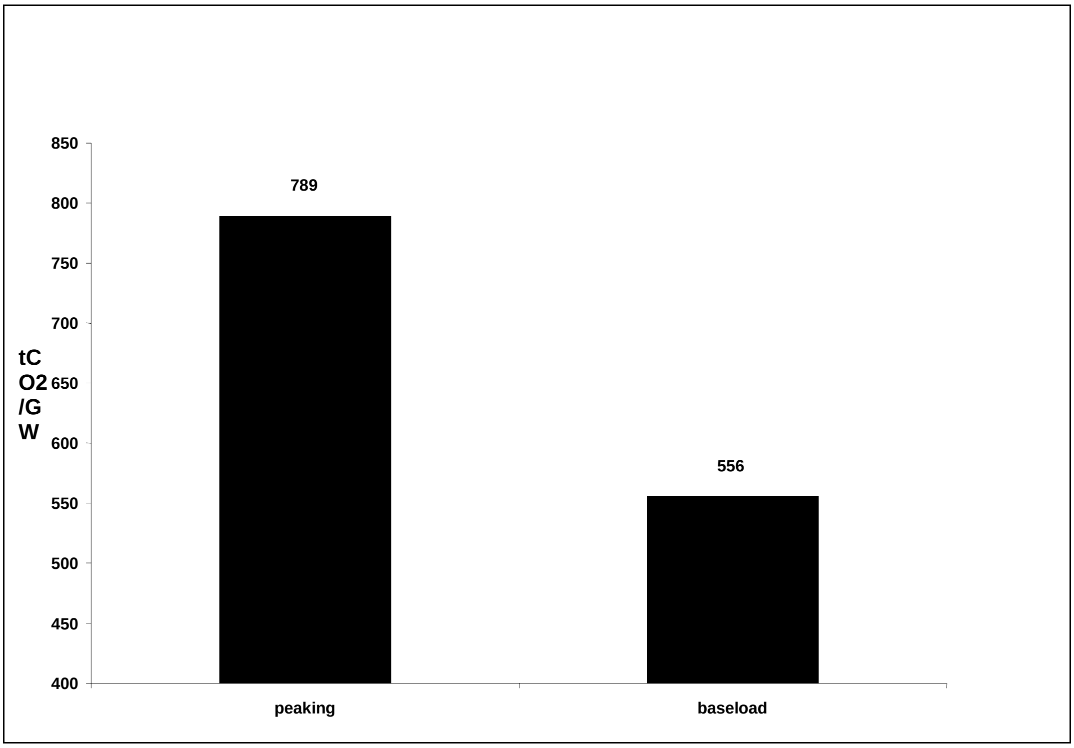
This option for disaggregated multi-project baselines certainly merits careful consideration, but it must be noted that the data needed to make this breakdown between the different plants operating in a country is difficult to obtain. However, reasonable general assumptions could be made about the types of power plants normally used to generate peak and baseload electricity.

Based on expert advice, a distinction between peaking plants (defined as all internal combustion engines and combustion turbines) and baseload plants (all other types) was made for India in order to test the options of developing peak load and baseload multi-project electricity baselines within a country. As shown in Figure 5 a multi-project baseline for India's *peaking* plants would be equal to 789 tCO_2/GWh; while a multi-project baseline for *baseload* plants would be almost 30% lower, at 556 tCO_2/GWh. The multi-project baseline for recent *baseload* capacity additions is essentially the same as the Indian multi-project baseline based on all recent capacity additions (including all sources) which was evaluated at 565 tCO_2/GWh. This is to be expected given the very large proportion (71%) of recent capacity additions in India assumed to be used to generate baseload electricity (they account for 96% of the total recent electricity generation).

Natural gas and oil are the typical sources used to generate peaking electricity. As a direct consequence of the lower conversion efficiency assumed for these plants and used for peaking electricity generation, the multi-project baseline level for peaking plants is naturally higher than the Indian gas-specific (418 tCO_2/GWh) and oil-specific (661 tCO_2/GWh) multi-project baselines, which are based on all plants (*i.e.* both peaking and baseload). However, a *peaking* multi-project baseline for India is lower than an Indian multi-project baseline based on *fossil fuel* recent capacity additions (960 tCO_2/GWh).

Figure 5

Multi-project baselines using recent capacity additions: Load-specific (India)



Caution has to be used when making assumptions for developing the peaking multi-project baseline. Setting an appropriate performance standard for peaking plants in developing countries poses particular challenges (compared to Annex I countries). In many cases where there is a supply shortage, power plants designed to generate peaking electricity are actually operated as mid-range or baseload plants. The Brazilian electricity situation provides a good example of typical peaking plants used to supply baseload electricity, as Brazil's North Isolated system relies almost exclusively on the types of plants normally used to generate peaking electricity. In fact, all the internal combustion engine units and 10 out of the 12 gas/combustion turbine units included in the database of recent Brazilian capacity additions for this case study are located in the North Isolated system. It is not realistic, at least in this case, to define a multi-project baseline for Brazilian peaking units as being composed of these two types of plants.

The development of peaking multi-project baselines therefore requires a careful consideration of each country's electricity situation, particularly in the case of developing countries experiencing power supply shortages.

6. Potential Stringency of Baselines

Ellis and Bosi (1999) concluded, “the maximum effectiveness of the project mechanisms (as opposed to individual projects) is unlikely to be achieved with […] overly stringent baselines”. Furthermore, maximising environmental stringency ought to be traded off against the desire to maximise the overall global environmental benefits from JI and CDM, where a greater number of good projects will be more beneficial for the environment than a smaller number of individually better projects.

Multi-project electricity baselines based on *recent* capacity additions provide a more accurate picture of what is happening under a business-as-usual scenario than multi-project baselines based on all existing capacity. However, they do not necessarily provide a more stringent multi-project baseline level. Not surprisingly, using multi-project baselines using *recent* capacity additions based on all sources results in a lower baseline level (because of the inclusion of zero-emitting nuclear, hydro and other renewables in the that baseline) than if the baseline calculations are based only on fossil fuel sources.

Figures 6, 7 and 8 below show, for Brazil, India and Morocco, the different stringency levels associated with various multi-project baseline options and their implications, in terms of the potential to generate emissions credits with different electricity sources.

Tellus (1999) remarks that better-than-average multi-project baselines are more promising and could help reduce the potential magnitude of free-ridership[44], although better-than-average multi-project baselines may increase the probabilities of missed emission reduction opportunities in the electricity sector.

Nonetheless, by definition, an average baseline based on all sources would mean that about half the power plants included in the sample used to develop the baseline would emit emissions below the average emission level. Consequently, the level of the average multi-project baseline (all sources) may be considered not sufficiently stringent to ensure long-term, additional greenhouse gas reductions. Of course, there could be exceptions to the general rule. For instance, the Brazilian example is particularly interesting in this context, as the level of the weighted average multi-project baseline using recent capacity additions, including all sources, is significantly more stringent than all the other baselines options presented in the three figures below.

The evaluation of “stringency” based on “average” performance depends on what exactly the “average” represents. For example, there is a significant difference between multi-project baselines based on the average emission rate of all recent capacity additions (all sources) and multi-project baselines based on the average emission rate of fossil fuel recent capacity additions. The former formulation of the “average emission rate” may already be viewed sufficiently stringent in some cases and perhaps too stringent in others (*e.g.* Brazil).

Still, it may be worth further considering in some cases the potential options for better than average multi-project baselines. For example, a better than average multi-project baseline could be defined as x% below the average multi-project baseline using recent capacity additions (including all sources). Other potential options may be to define it as better than the 75th percentile, or setting the baseline at one or two standard deviations below the average emission rate[45].

[44] For more discussion on the issue of free-ridership in the context of different emissions baselines for the project-based mechanisms, see Ellis and Bosi (1999).

[45] This was suggested by CCAP (2000) for retrofit projects for which credits would be calculated based on the average emission rate of all existing projects.

Figure 6

Brazil: Implications of multi-project baselines using recent capacity additions

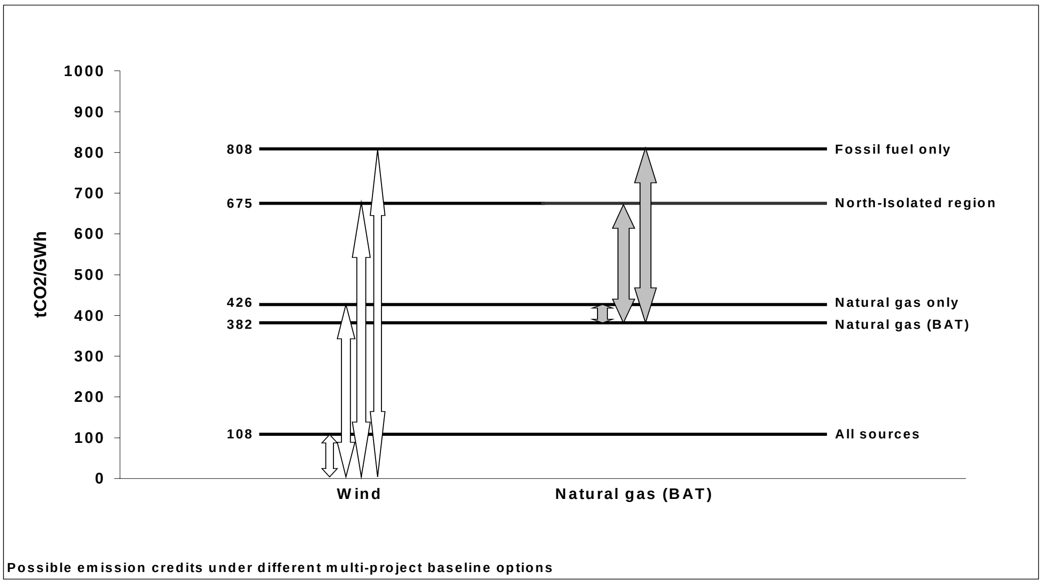


Figure 7

India: Implications of multi-project baselines using recent capacity additions

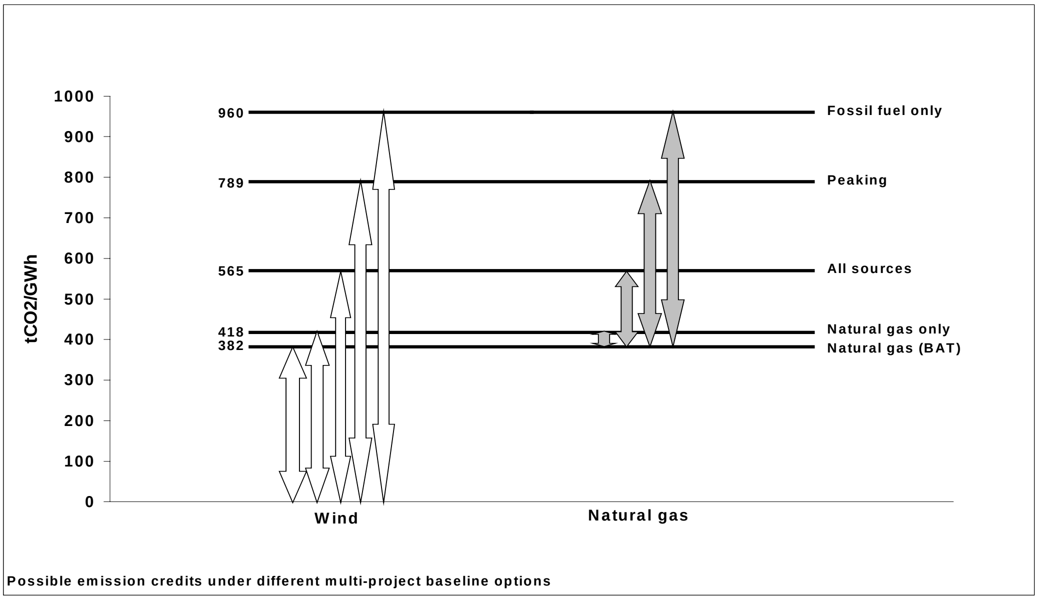
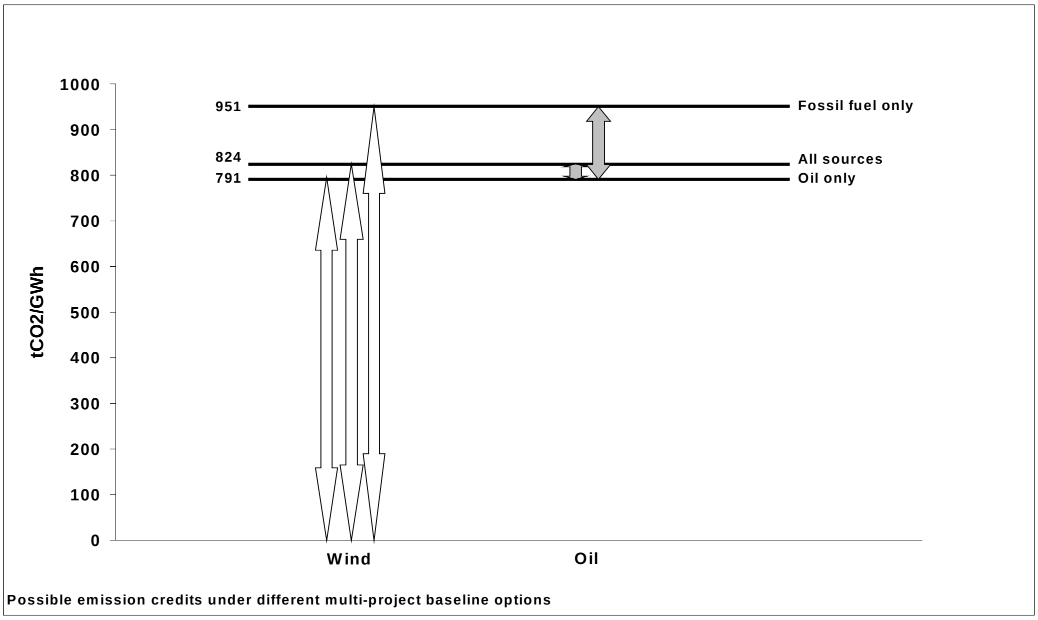


Figure 8

Morocco: Implications of multi-project baselines using recent capacity additions



Under all the different options examined to develop multi-project baselines for electricity generation projects, non-emitting sources would, theoretically, be eligible to generate emissions credits, although they may simply be part of the business-as-usual trend in the country's electricity generation sector. Tellus (1999) suggests that it might be useful to consider a "hybrid [multi-project] approach for the power sector". This could be done, for example, by having an activity additionality test which would screen out projects or types of power plants that have a significant probability of generating non-additional emission credits. Another expert, Erik Haites[46], also suggests a kind of hybrid approach taking the form of a more elaborate evaluation process - not a different baseline - but would limit it to "large" projects to avoid creating an insurmountable burden for small projects. UNIDO (2000) also recommends adding "additionality" checks, of a qualitative nature, to the baseline test in order to make a better assessment of the JI/CDM nature of proposed projects. Such approaches may merit further consideration.

This case study and the multi-project baselines constructed based on recent capacity additions are focussed on new power plants (and not improvements to existing power plants). While further consideration should be given to whether (and if so, how) greenfield projects should/could be treated differently than refurbishment projects in the electricity sector (in terms of different crediting different timeline, or different stringency level of the same baseline assumption, for example), it is important that both types of electricity projects be treated in a consistent manner in order to create a level playing field and avoid unwanted incentives in the electricity generation sector. For example, given that many developing countries are projected to increase significantly their electricity production to meet currently unmet or future demand, it would be important not to create a negative bias against greenfield project (versus refurbishment projects), as this could be a disadvantage for countries experiencing rapid electricity growth in their efforts to attract CDM investments.

[46] Based on his presentation at the IPIECA Workshop on Issues, Barriers and Opportunities for Practical Application of the Kyoto Mechanisms, Milan, Italy, April 6 and 7, 2000.

7. Potential Volume of Projects

One of the main criteria for evaluating the success of JI and CDM is likely to be the number of additional climate-friendly projects that these Kyoto mechanisms were able to stimulate. Baseline stringency is a key determinant of electricity project volumes. The potential volume of projects in the electricity sector will depend on the number of emission credits and their value, that can be expected from electricity projects. Total project volumes (through a more or less significant global supply of credits) will also influence the international price of each emission credit. Furthermore, baseline stringency determines the magnitude of credit revenue streams from any one project and thus whether these revenues affect project feasibility.

Clearly the more stringent the baseline level, the fewer (if any) the calculated emission reductions and, hence, the credits earned by an electricity project. Compared to a scenario where the same electricity project would earned more emission credits, the value of each emission credit will have to be higher, as the total volume is smaller under a more stringent emission baseline, to change business-as-usual behaviour.

The box below illustrates, through simple calculations and a series of assumptions, the potential volume and value of the emission credits earned by a hypothetical CDM electricity project. The example is based on a new BAT natural gas plant in India compared to the Indian multi-project baseline based on recent capacity including all sources. Compared to a multi-project baseline based on fossil fuel only recent capacity, this is a relatively stringent baseline level. The crediting lifetime associated with the multi-project baseline is assumed to be 10 years[47], meaning that the project developers can expect, from the start, a certain volume of credits (assuming the electricity project performs as planned, *i.e.* emitting 382 tCO_2/GWh) for this period. After that, the project may potentially still earn emission credits if its GHG emissions are below the level set by the updated baseline, but this was not taken into account.

The total annual costs (including investment, operation and maintenance, as well as fuel costs) and electricity revenues of the new Indian plant are presented based on both a 5% and 10% discount rate[48] to show the impact of the financing terms on the economic feasibility of a potential electricity project. Neither of these discount rates allows the project to go ahead, on economic grounds, as the costs are greater than the revenues.

Compared to the Indian multi-project baseline based on recent capacity including all sources (*i.e.* 565 tCO_2/GWh), the new BAT gas plant would reduce emissions by 183 tCO_2/GWh, so 183 emissions credits could be earned per year. The annual value of these emission credits, discounted at 5%, would be worth 604,847US$ if emission credits were worth 5US$/$tCO_2$ or 1,225,138US$ US$/year if emission credits were worth 10US$/ tCO_2[49]. While certainly significant in absolute terms, the revenue from the sale of the potential emission credits from such a CDM project need to be examined in relative terms.

According the example provided in the box below, the annual value of the emission credits relative to estimated annual electricity revenues (discounted at 5%), represent 9.6% if emission credits are worth 5US$/$tCO_2$ and 19% if emission credits are worth 10 US$/$tCO_2$. The revenues from the CDM credits would thus help increase the potential revenues from the hypothetical new BAT gas plant, but would not

[47] Further analysis could include comparing implications of different crediting timelines, *e.g.* 10 and 15 years.

[48] The discount rates seek to reflect private and public financing practice.

[49] The emission credits price assumption of 5 or 10 US$ per tonne of CO_2 is consistent with various model results. For example, the survey of modelling results by Baron (in IEA, October 1999) indicates 7.6 US$/$tCO_2$ is the average estimated price of emission credits under "global trading" (which includes CDM).

be sufficient to make it economically feasible. At a 5% discount rate, the CDM credits contribute to reducing the annual net deficit by 16.2% if emission credits are worth 10 US$/t$CO_2$.

Of course the evaluation of the contribution of the emission credits from a potential CDM project critically depends on the assumptions made. In addition, this example does not take into account each investor's criteria (*e.g.* internal rate of return, net present value, capital efficiency, payback period, risk evaluation, *etc.*), which can be expected to raise the feasibility threshold. The magnitude of the impact of the CDM emission credits would certainly be different if the price of emission credits were much higher and the volume of emission reductions and thus emission credits were also greater (*e.g.* comparing a zero-emitting project to the same baseline as in the example in the box below).

It is, in fact, impossible to draw a general conclusion on the potential volume of projects under different multi-project baseline options, as results will vary according to the type of project, its total net cost, the volume of emission credits, the price of emission credits as well as the financing terms and feasibility criteria. Nonetheless, this example provides insights on the potential small contribution of the CDM credits (at the credit prices generally estimated by models) on electricity investments and confirms what others have concluded (*e.g.* Lanza 1999 in IEA 1999): in order for the emission credits to have an impact on the investment decision, proposed CDM projects may need to be already very close to meeting, or have already met, the basic feasibility criteria from an investor's point of view.

8. Insights and Conclusions

Standardisation of emission baselines

Standardisation of emission baselines (or multi-project baselines) for electricity projects in the context of the Kyoto Protocol's JI and CDM is possible and desirable to increase transparency and consistency between similar projects in similar circumstances and to reduce overall transaction costs of the mechanisms. Multi-project electricity baselines will also facilitate the calculation of the GHG mitigation potential of other projects, such as energy efficiency projects.

What could the CDM potentially be worth for a BAT CCGT gas plant in India?

Assumptions

The CDM project is assumed to be a 50 MW CCGT plant, generating 325 GWh per year with a conversion efficiency of 52.9%; a load factor of 0.75 and emissions of 382tCO_2/GWh at a cost of 4.77cents/kWh (Ellis and Bosi, 1999). The baseline is drawn up using the average GHG intensity of recent capacity additions (all sources), *i.e.* 565 tCO_2/GWh. A ten-year lifetime is assumed.

The Economic life of the plant is taken to be 40 years and the Indian electricity tariff at 4.5 cents/kWh**. The effect of two discount rates (5% and 10%) and two prices of emission credits (CERs) (5 and 10 US$/t$CO_2$) are calculated.

Calculations

Cost of new Indian plant:
- Cost per GWh* = 47,700 US$/GWh (@ 10% discount rate) or 42,520 US$/GWh (@5% discount rate)
- Cost per year = 15,507,270 US$ (*i.e.* 47,700US$/GWh * 325.1 GWh per year) or 13,823,252 US$ (*i.e.* 42,520 US$/GWh*325.1GWh per year)

Revenue from new Indian plant's electricity generation (without emission credits):
- Revenue per GWh = 45,000 US$/GWh
- Revenue per year = 6,274,005 US$ (@5% discount rate); ; 3,558,622 US$ (@10% discount rate)

Net deficit of new Indian plant (without emission credits):
- (7,549,247 US$) @ 5% discount rate; or (11,948,648 US$) (@ 10% discount rate)

Volume of emission credits:
- Number of emission credits/GWh = 183 (*i.e.* 565 tCO_2/GWh - 382 tCO_2/GWh)
- Number of emission credits per year = 59,493 (*i.e.* 325.1 GWh/year * 183 emission credits/GWh)

These 59,493 credits are worth 297,465 US$ at 5 US$/t$CO_2$; or 594,930 US$ at 10 US$/t$CO_2$. The value of annual discounted emission credits are indicated in the following table.

(continued)

What could the CDM potentially be worth for a BAT CCGT gas plant in India?

(US$)

Discount rate	Annual Discounted Generation Costs (000 $)	Annual Discounted Revenues (without credits) (000 $)	Annual Discounted Revenues minus costs (000 $)	Discounted Revenues (incl. emission credits) minus costs (annual) (000 $)		Value of annual discounted CERs (000 $)	
				5 $/tCO_2$	10 $/tCO_2$	5 $/tCO_2$	10 $/tCO_2$
5%	13,823	6,274	(7,549)	(6,944)	(6,324)	605	1,225
10%	15,507	3,559	(11,949)	(11,467)	(10,974)	481	975

* Cost figures based on NEA/IEA (1998): as no India-specific data was available, costs estimated to be similar to those of Korea (as in Ellis and Bosi 1999);
** Tariff for 1997;
Source: From Pew Center (1999), based on TERI Energy Data Directory and Yearbook 1998/1999.

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Data set

Developing multi-project baselines using recent capacity additions provides a closer reflection of what would happen in the electricity sector under a business-as-usual scenario than more aggregated approaches. For example, a multi-project-baseline based on all existing capacity would include emissions from all plants, including those from old inefficient plants that started operating 15-25 years ago, although such plants and technologies are no longer routinely installed in BAU investments today. This would not happen when using multi-project baselines based on recent electricity capacity additions.

Boundaries

For practical reasons and in order to avoid double counting of emission reductions, it appears appropriate to set project boundaries around direct emission impacts (ideally all GHGs, but CO_2 emissions would be sufficient) of electricity generation for the development of multi-project baselines.

Historical or projection data

Given the inherent uncertainties associated with energy and electricity projections, particularly in the case of rapid growth and increased liberalisation, it appears reasonable and possibly less controversial (in terms of avoiding a debate on what is the “accurate” projection) to develop multi-project baselines for the electricity sector using recent historical data. This data, in the context of developing electricity multi-project baselines, could be defined as recent capacity additions based on additions over the last 3 to 5 years, as well as those currently under construction, in any one country (or, depending on the size of the country, region within a country or group of small countries). Taking into account only capacity additions in the most recent years would increase the likelihood that the multi-project baselines reflect business-as-usual investments in the electricity sector.

Crediting lifetime

The decision on the timeline during which a particular electricity multi-project baseline will be valid for potential projects needs to be specified up-front to provide greater certainty to project developers and increase transparency and consistency between similar projects. The timeline would need to take into account the relative inertia of electricity capital stock as well as the need to ensure additional and long-term GHG reductions. The consideration of various factors (*e.g.* technical lifetime, economic lifetime or debt payback period) combined with various objectives (*e.g.* environmental, economic and practicality) should guide the determination of the crediting lifetime associated with an electricity multi-project baseline. Nonetheless, a baseline crediting lifetime of around 10-15 years may be considered appropriate.

It is unclear whether a distinction, in terms of crediting lifetime, should be made between “greenfield” and “refurbishment” projects and if it were made, how it could be defined adequately. Such a distinction was not made in the case study (as it was based on new capacity additions), but this issue may merit further investigation.

Timing of baseline updates

Given the non-static nature of developments in the electricity sector, it is important to update the multi-project baselines at regular intervals in order to ensure that future electricity projects use an adequate multi-project baseline, reflecting the electricity situation at that time. However, in order to gain economies of scale from the development of multi-project baselines and minimise overall baseline development costs for JI and CDM, updates need to be made at reasonable intervals. It appears reasonable to periodically update the electricity multi-project baselines, such as every 5 years.

Aggregation

With respect to the level of aggregation, multi-project electricity baselines appear to be more reliable if they are country-based electricity profiles in order to take into account the different national circumstances. Sub-country multi-project electricity baselines may be appropriate for large countries and multi-countries may be adequate for a group of small countries.

Data quality and availability

In general, the more disaggregated the standardisation, the greater the data requirements, with implications on overall costs of developing baselines. However, disaggregated standardisation, based on plant-level data of recent capacity additions, as was done in this case study, is generally a better reflection of "what would occur otherwise" than baselines based on highly aggregated data and is thus recommended.

The development of disaggregated electricity multi-project baselines based on recent capacity additions requires the following information for each plant/unit included in the sample to develop the multi-project baseline:

1. Commissioning year;
2. Type of technology;
3. Source of electricity (*i.e.* fuel used);
4. Generating capacity;
5. Load factors;
6. Conversion efficiency; and
7. Emission factor(s) for fuel used.

The database used for this case study includes data, for each plant, on the commissioning year, the type of technology, the generating capacity and the source of electricity. Reasonable assumptions, based on expert advice, were made for the load factor and the conversion efficiency, albeit at a country-level (and not specific to each individual plant within a country).

The IPCC Guidelines for National Greenhouse Gas Inventories should be used when developing multi-project electricity baselines. These will provide basic assumptions about carbon content of fuels and energy content factors to provide comparability in the baseline construction.

It is normal for databases to have some "unknown" or "unspecified" values that require some research to find the correct value or to estimate it. Current data constraints need to be taken into account in decisions on baselines for electricity projects, but should not be considered a barrier. Assumptions, based on expert advice, can be made where data is not available. Moreover, the emergence of the CDM and JI mechanisms may stimulate the monitoring, reporting and publication of more detailed and reliable data. The process to develop electricity multi-project baselines should thus be viewed as an evolving one, improving over time.

Potential baseline assumptions:

Different assumptions can be used to develop multi-project baselines based on recent capacity additions. This case study examined multi-project baselines based on recent capacity additions, according to: (i) all sources; (ii) only fossil fuels; (iii) source-specific; (iv) region-specific; and (v) load-specific. The implications of these baseline assumptions, in terms of stringency, are different for different countries (Figures 6, 7 and 8 provide good illustrations of the different implications).

In the case of Brazil and India, clean coal plants could generate the largest volume of emission credits under source-specific multi-project baselines. This outcome may not be considered, by some, as consistent with the environmental objective of the CDM. In fact, source-specific multi-project baselines, particularly in the case of coal, may result in perverse incentives (*e.g.* for example, reducing the relative incentive to develop alternative cleaner technologies such as natural gas). Of course, such baselines might promote a cleaner use of coal than would otherwise be the case - which for countries like India and China, with huge coal reserves, could be an important variable in promoting a more environmentally-benign infrastructure.

With Brazil serving as an example for other large countries with different circumstances within their borders (*e.g.* India), it may be appropriate to further consider the development of separate multi-project baselines for different regions within a country. At a minimum, the development of separate multi-project baselines for off-grid, isolated electricity systems would be useful.

Developing separate multi-project baselines for peak and baseload electricity was done in the case of India, based on expert advice and assumptions. Given that the majority of recent plants are assumed to generate baseload electricity, the multi-project baseline for baseload electricity is very similar to the country's multi-project baseline using all sources. However, the multi-project baseline for peaking electricity is quite a bit higher, due to the typically lower efficiency of the gas and oil-fuelled power plants generating peak electricity. Developing a separate multi-project baseline for peaking electricity may be desirable, as those plants are typically different from baseload plants. However, caution has to be taken when making assumptions on which plant type would constitute the "peaking electricity generation" sample and seeking country experts' advice is strongly recommended.

Potential stringency of baselines

Multi-project baselines based on recent capacity additions provide a good reflection of "what would happen otherwise" but are not necessarily more stringent than multi-project baselines based on all existing capacity. This is because recent capacity additions are not always lower GHG-emitting power plants. A good example of such as situation is Brazil where the main source of power generation is hydro, but the share of hydro is slowly diminishing (and this is projected to continue) due to increases in thermal power facilities.

Thus, the same multi-project baseline approach implies different levels of stringency in different countries.

The evaluation of "stringency" based on "average" performance depends on what exactly the "average" represents. For example, there is a significant difference, in terms of the level, between multi-project baselines based on the average emission rate of recent capacity additions including all sources and multi-project baselines based the average emission rate of recent fossil fuel capacity additions, with the former being more stringent than the latter. In fact, the “average emission rate” of all recent capacity additions may be viewed sufficiently stringent or perhaps too stringent in some cases (*e.g.* Brazil).

Still, it may be worth further considering the potential options and implications for “better-than-average” electricity multi-project baselines. For example, a better than average multi-project baseline could be defined as emitting x% below the average multi-project baseline using recent capacity additions (including all sources). Other potential options may be to define it as better than the 75th percentile, or setting the baseline at one or two standard deviations below the average emission rate.

Regardless of the stringency of the multi-project baseline for electricity generation projects, non-emitting sources would be eligible to generate emissions credits, although they may simply be part of the business-as-usual trend in countries’ electricity generation sector. It might thus be useful to consider a “hybrid” approach to assessing the GHG additionality of those zero-emitting projects. For example, it may be worth considering an activity additionality test, which would screen out projects or types of power plants that have a significant probability of generating non-additional emission credits. In order to focus on larger plants that have the potential to lead to larger volumes of non-additional emission credits, another option would be to require large zero-emitting projects to go through a more elaborate evaluation process. Small renewable projects would only need to pass the multi-project baseline test.

This case study did not make a distinction between baselines for greenfield and refurbishment projects. A preliminary view is that it does not seem necessary or practical to distinguish between baselines for refurbishment and greenfield power projects. Nonetheless, further consideration should be given to whether (and if so, how) greenfield projects should/could be treated differently than refurbishment projects in the electricity sector (in terms of different crediting, different timeline and/or different stringency level of the same baseline assumption, for example). A practical definition to make this distinction would be needed. Furthermore, it is important that both types of electricity projects be treated in a consistent manner in order to create a level playing field and avoid unwanted incentives in the electricity generation sector. The details of the overall CDM decision-making process have yet to be agreed-upon by the international community. However, the final decision on which multi-project baseline(s) is/are most appropriate and at what level of stringency, can be expected to be a decision tailored to national circumstances, based on environmental, economic, administrative and data availability criteria. Further consideration might be warranted to determine whether and, if so, what type of guidance could be developed internationally to ensure consistency among similar projects in similar circumstances.

Potential volume of projects

It is not possible to assess quantitatively the volume of electricity projects that could be stimulated under various electricity multi-project baselines.

Clearly, the more stringent the emission baseline, the fewer (if any) the GHG reductions and, hence, the emission credits earned by an electricity project.

This case study provides a quantitative example of the potential volume and value of emission credits that could be earned by a hypothetical new BAT gas plant in India and how they could affect the economic feasibility of the project.

The evaluation of the contribution of the emission credits from a potential CDM project critically depends on the assumptions made (*e.g.* cost and revenues of the project, type of financing, discount rate, *etc.*). A key factor, which cannot be generalised, is each investor's financial criteria (*e.g.* internal rate of return, payback period, risk assessment). It is thus not possible to draw general conclusions on the potential volume of projects under different multi-project baseline options, but if this case study is representative of other projects, the CDM impact (based on the emission credit prices generally estimated by models) on investment decisions could be relatively small.

Annex A: Calculation of multi-project electricity baselines based on recent capacity additions (*i.e.* those that started operating after 1994 and those currently under construction)

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:

Equation A3-1

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

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

Equation A3-2

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

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:

Equation A3-3

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

The gigagrams of CO_2 emissions ($GgCO_2$) for each plant are then converted into tonnes of CO_2 emissions (tCO_2). (1Gg = 1t)

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

Equation A3-4

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

The kilograms of CH_4 emissions (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 21[50]. These CO_2 equivalent emissions then need to be translated into tonnes of CO_2 equivalent (tCO_2).

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:

[50] IPCC, Second Assessment Report (1997)

Equation A3-5

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

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

Equation A3-6

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

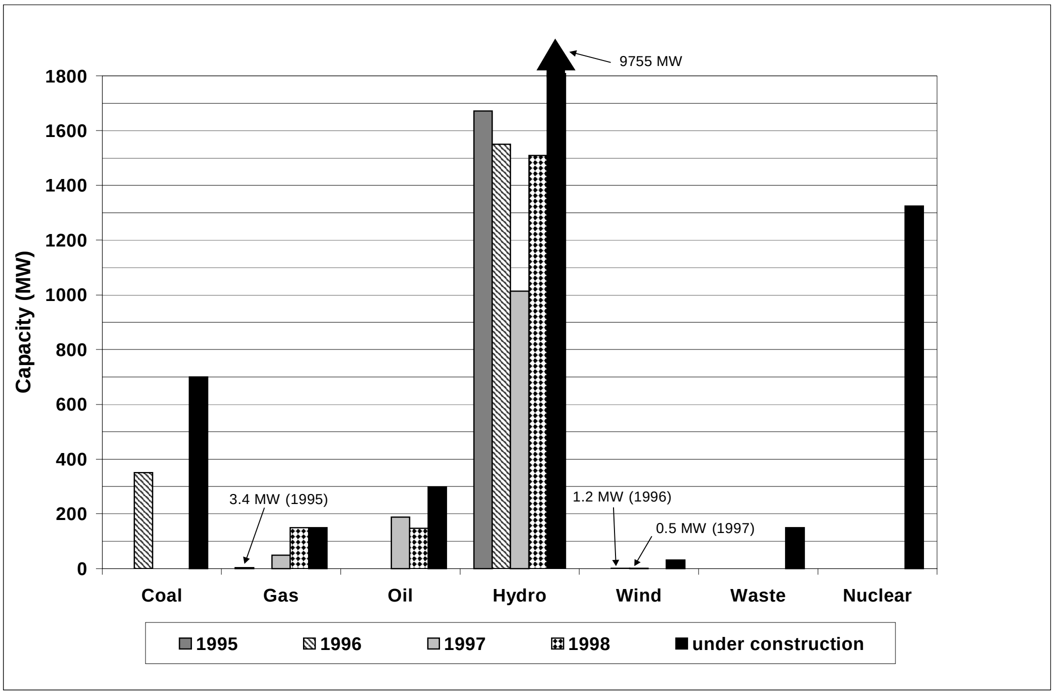
Where:

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

Annex B: Recent electricity capacity additions in Morocco, Brazil and India

Figure B-1

Brazil: Recent electricity generation capacity (1995, 1996, 1997, 1998 & plants under construction)



Source: UDI/McGraw- Hill (1999)

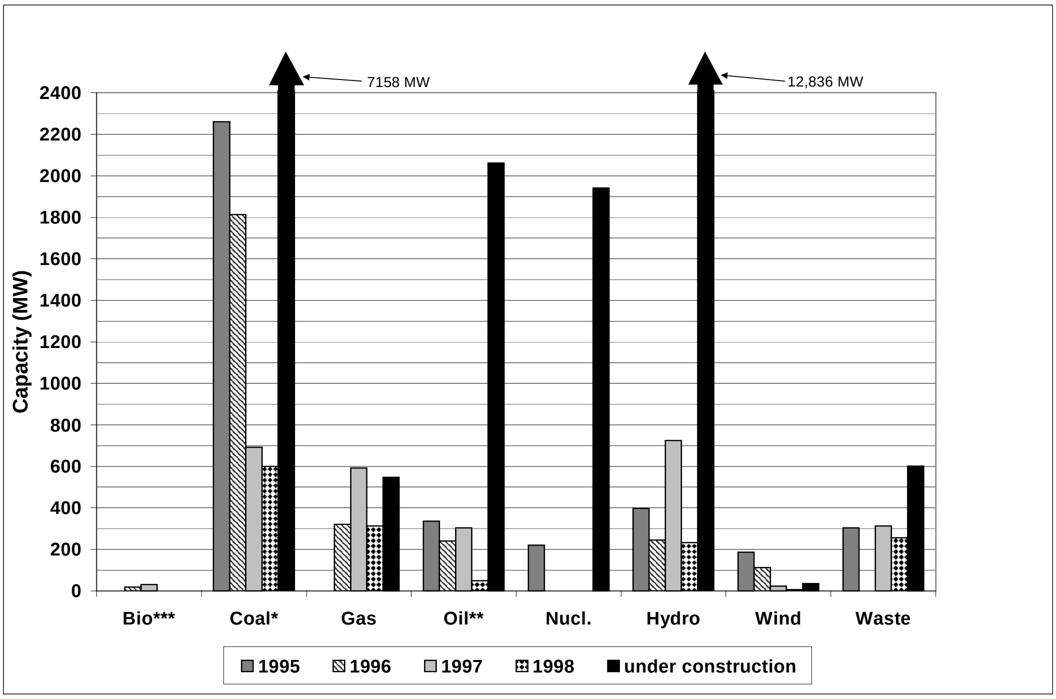
Table B-2

Brazil: Number of recently added generating units (excludes CHP plants)

Source	1995	1996	1997	1998	Under const.	Total
Coal	0	1	0	0	2	3
Gas	1	0	1	1	1	4
Oil	0	0	19	4	93	116
Nuclear	0	0	0	0	1	1
Hydro	7	9	11	8	64	99
Wind	0	1	1	0	3	5
Waste	0	0	0	0	1	1
Total	8	11	32	13	165	229

Figure B-3

India: Recent electricity generation capacity (1995,1996,1997,1998 & plants under construction)



Source: UDI/McGraw-Hill, 1999

**incl. coke oven gas, blast furnace gas & coal gas*
***incl. naphtha & petroleum coke*
**** Biomass includes bagasse*

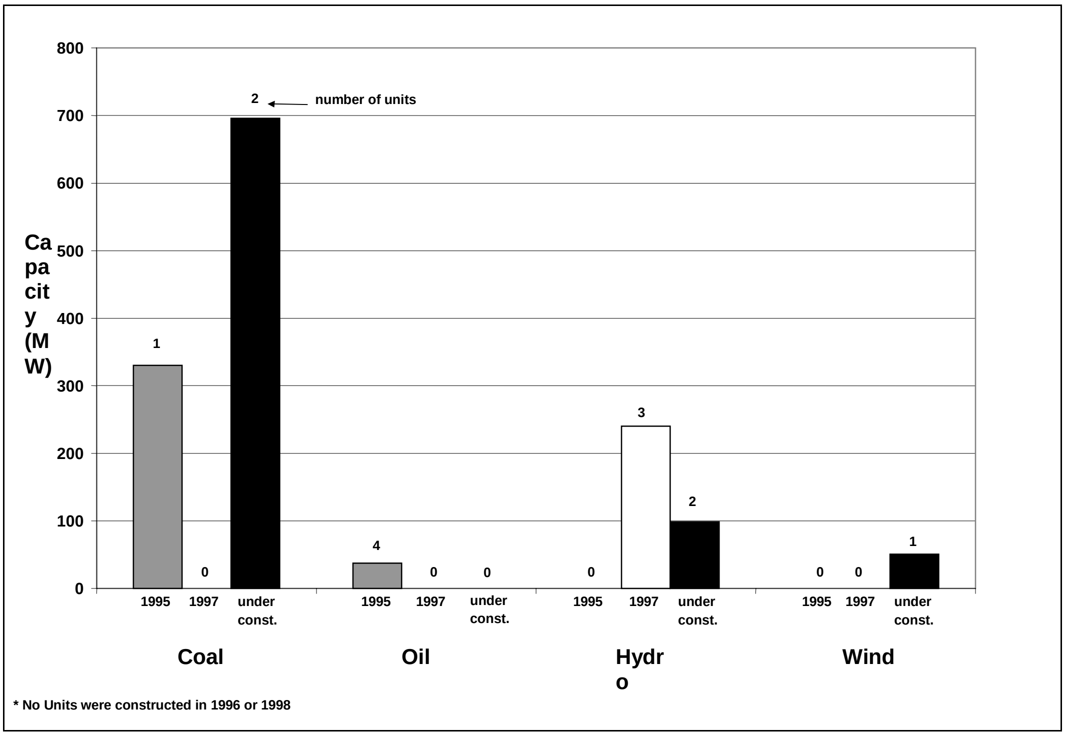
Table B-4

India: Number of recently added generating units (excludes recent CHP plants)

Source	1995	1996	1997	1998	Under const.	Total
Coal	8	10	10	5	35	68
Gas	0	14	15	2	4	35
Hydro	11	27	20	7	125	190
Oil	46	46	39	4	35	170
Nuclear	1	0	0	0	6	7
Wind	105	17	5	2	2	131
Biomass	0	1	1	0	0	2
Waste	2	0	5	2	5	14
Total	173	115	95	22	212	617

Figure B-5

Morocco - Recent Electricity Generation Capacity*
(1995, 1997 and Plants under construction)



Source: UDI/McGraw-Hill, 1999

* No units were constructed in 1996 or 1998

Annex C

Table C-1

Recent (operation started after 1994) electricity generation plants and plants under construction: Assumptions for load factors and efficiencies

	Brazil	India	Morocco
Steam turbine (boiler)			
- Efficiency**	35%	32*%	35%
- Load	75%	70*%	75%
Hydro[1]			
- Load	50%**	40%	32%***
Nuclear			
- Load**	69%	46*%	n.a.
Gas turbine in combined cycle			
- Efficiency**	50%	50%	50%
- Load	75%	75%	75%
Internal combustion (reciprocating engine or diesel engine)			
- Efficiency	33%	33%	33%
- Load	50%[2]	35%	35%
Gas/combustion turbine (peak load)			
- Efficiency**	35%	35%	35%
- Load	50%[2]	35%	35%
Wind turbine generator			
- Load	25%**	25%	25%

* Lower values for India are due to poor maintenance and low quality coal in India.
** Based on IEA (1998a) assumptions.
***African average, as per IEA (1998a)

[1] Hydro performance is site specific, but to facilitate calculations, an average figure is used here, based on IEA (1998a) assumptions.

Other figures based on recommendations from electricity experts at the IEA.

[2] A load of 50% is assumed for the North Isolated region (all internal combustion engine plants are located in that region and 10 out of the 12 gas/combustion plants are located in the North Isolated region). The load factor is assumed to be 0.35% for these types of plants located in other regions.

Annex D

Table D-1

Baselines based on entire existing generation capacity in 1997 (t CO_2/GWh)

	All existing electricity generation capacity (fossil fuel only)	**All existing electricity generation capacity (all sources)**
Brazil	894	49
India	1117	912
Morocco	884	745

Sources: IEA 1999b, IEA 1999a

Annex E: National baselines based on recent capacity additions (after 1994) and those currently under construction

Table E-1

Brazil

Electricity source	No. of plants	Total capacity (MW)	Electricity output (GWh)	Percentage of total electricity output	GHG emissions (tCO_2/GWh) *Weighted average*
All sources	229	19,040.80	87,912.72	100%	108.03
Fossil fuel only	123	2,034.30	11,754.79	13.4%	807.93
Hydro	99	15,487.80	67,182.96	76.4%	0.00
Nuclear	1	1,325.00	7,926.55	9%	0.00
Oil	116	632.90	2,642.18	3%	761.2
Natural Gas	4	351.40	2,284.98	2.6%	426.4
Coal	3	1,050.00	6,827.63	7.8%	953.7
Wind	5	33.70	73.04	0.1%	0.00
Waste heat	1	150.00	975.38	1.1%	0.00

N.B. OIL includes diesel oil, heavy fuel oil and distillate oil; COAL includes bituminous coal.

Table E-2

India

Electricity source	No. of plants	Total capacity (MW)	Electricity output (GWh)	Percentage of total electricity output	GHG emissions (tCO_2/GWh) *weighted average*
All sources	617	35770	168,710	100%	565
Fossil fuel only	273	17286	99,352	58.9%	960
Nuclear	7	2,160	8,615	5.1%	0.00
Waste heat	14	1,475	9,592	5.7%	0.00
Biomass	2	49	295	0.2%	0.00
Hydro	190	14,437	50,069	29.7%	0.00
Natural Gas	35	1,774	10,493	6.2%	418
Oil	170	2,990	12,842	7.6%	661
Coal	68	12,523	76,017	45.1%	1,085
Wind	131	363	787	0.5%	0.00

N.B. 'Oil' includes diesel oil, heavy fuel oil, distillate oil and naphtha; COAL includes bituminous coal, sub-bituminous coal, lignite, coke-oven-gas, blast furnace gas and coal gas from coal gasification; BIOMASS includes bagasse.

Table E-3

Morocco

Electricity source	No. of plants	Total capacity (MW)	Electricity output (GWh)	Percentage of total electricity output	GHG emissions (tCO_2/GWh) *weighted average*
All sources	13	1,452	7,834	100%	824
Fossil fuel only	7	1,064	6,786	86.6%	951
Hydro	5	338	939	12%	0.00
Oil	4	38	114	1.5%	791
Coal	3	1,026	6,672	85.2%	954
Wind	1	50	109	1.4%	0.00

Annex F: Disaggregated baselines based on recent capacity additions (after 1994) and those under construction

Table F-1

Brazilian sub-national baselines based on recent capacity additions (after 1994) and those under construction

Region	Electricity sample	No. of plants	Total capacity (MW)	Electricity output (GWh)	% of total Brazilian electricity output	GHG emissions (tCO_2/GWh)
Brazil	All sources	229	19,041	87,913	100%	108
Brazil	Fossil fuel only	123	2,034	11,755	13.4%	808
North Isolated	All sources	116	628	2,724	3.1%	677
North Isolated	Fossil fuel only	114	555	2,405	2.7%	764
North-Northeast	All sources	14	3,435	14,850	16.9%	0.60
North-Northeast	Fossil fuel only	1	3.40	22	0.03%	403
South/South-east/Midwest	All sources	99	14,978	70,338	80.0%	109
South/South-east/Midwest	Fossil fuel only	8	1,476	9,327	10.6%	820

Table F-2

Indian baselines for peak and baseload based on recent capacity additions (after 1994) and those under construction

Type of plants	No. of plants	Total capacity (MW)	Electricity output (GWh)	% of total Indian electricity output	GHG emissions (tCO_2/GWh)
Peaking	177	2,199	6,674	3.96%	789
Baseload	440	33,571	162,036	96.04%	556

N.B. Peaking plants are assumed to be gas/combustion turbine plants and internal combustion engine plants. Baseload plants are assumed to be all other types of power plants.

Glossary

additive (or extender)	material(s) added to clinker to make cement
AEEI	autonomous energy efficiency improvement
AIJ	activities implemented jointly
AIXG	Annex I Experts Group on the United Nations Framework Convention on Climate Change (UNFCCC)
audit-based programmes	Programmes that rely on the systematic collection of data on building and energy system performance characteristics at the customer site. The goal of these programmes is typically to identify and quantify energy efficiency improvement opportunities in combination with an implementation plan.
baseload	The minimum amount of electric power delivered or required over a given period of time at a steady rate.
BAU	business as usual
bench tests	Tests of equipment performance characteristics conducted in a controlled environment such as a laboratory or manufacturer's test facility.
BF	blast furnace
blast furnace slag	One of the common additives used in cement. It is the by-product of iron and steel manufacture and grinding this additive for use in cement is energy intensive.
BOF	basic oxygen furnace
CDM	Clean Development Mechanism (project-based mechanism introduced in Article 12 of the Kyoto Protocol)
CFL	compact fluorescent lamp
CH_4	Methane
CHP	Combined heat and power. A plant that is designed to produce both heat and electricity
cli	Clinker
clinker	The key component of cement and the most GHG-intensive.
CO	coke oven
CO_2	carbon dioxide
combined cycle	An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. This process increases the efficiency of the electric generating unit.

conversion efficiency	Efficiency at which a thermal power plant converts input fossil fuel (*i.e.* coal, gas, or oil) into electricity.
crediting lifetime	Length of time (in years) during which a project can generate emission credits.
demand-side management (DSM)	Utility programmes designed to control, limit or alter Energy consumption by the end user. DSM objectives may include energy conservation, load management, fuel substitution and load building.
diversity factor	The ratio of the peak demand of a population of energy-consuming equipment to the sum of the non-coincident peak demands of the individual equipment.
DR	direct reduction
DRI	direct reduced iron
dry process	A process whereby the raw materials for cement production are ground and then mixed (as a dry powder).
EAF	electric arc furnace
EEI	energy efficiency index
EIT	countries with economies in transition
EJ	exajoule (= 10^{18} Joule)
emission credits	Unit used for the measurement (*e.g.* in tonnes of CO_2-equivalent), transfer and acquisition of emission reductions associated with JI and CDM projects.
end-use indices (EUI)	The ratio of the energy use of a building, system or end-use over a given time period to a commonly recognised index of size or capacity. Examples include lighting energy use per square foot of floor area and motor energy use per unit of production output.
environmental credibility	Quality of a baseline with respect to realistically reflecting the emission level that would likely occur without the JI or CDM project(s).
environmental effectiveness	Extent to which the project-based mechanisms result in maximum emission reductions and maximum participation through JI and CDM projects, thereby contributing to achieving the objectives of the Kyoto Protocol.
EU or EU15	The 15 members states of the EU.
fluorescent lamps	A discharge lamp whereby a phosphor coating transforms ultraviolet light into visible light. Fluorescent lamps require a ballast that controls the starting and operation of the lamp.

free riding	A situation whereby a project generates emission credits, even though it is believed that the same project would have gone ahead, even in the absence of JI or CDM. The emission reductions claimed by the project would thus not really be “additional”. Free riding therefore affects the number of projects obtaining credits under JI and CDM.
gaming	Actions or assumptions taken by the project developer and/or project host that would artificially inflate the baseline and therefore the emission reductions. Gaming therefore affects the amount of emission credits claimed by a JI or CDM project.
GHG	greenhouse gas
GJ	gigajoule (= 10^9 Joule)
greenfield projects	New projects (as opposed to existing plants that are refurbished)
grid	The layout of an electrical distribution system.
GWh	gigawatt hour, *i.e.* 10^9 Wh.
GWP	global warming potential
hp	horsepower
HPS	High pressure sodium lamps.
HVAC	Mechanical heating, ventilating and air-conditioning of buildings.
IEA	International Energy Agency
incandescent lamps	A lamp that produces visible light by heating a filament to incandescence by an electric current.
ISP	integrated steel plant
JI	Joint implementation (project-based mechanism introduced in article 6 of the Kyoto Protocol).
kWh_e	kilowatt hours of electricity use
leakage	Leakage occurs if actual emission reductions (or sink enhancements) from a CDM or JI project lead to increases in emissions (or sink decreasing) elsewhere.
load curve	A plot of the demand placed on an energy system during an hour, day, year or other specified time period.
load factor	Number of hours in a year during which a power plant is generating electricity.
market segment	A segment of a customer or end-user market identified by common demographic, firmographic or energy use characteristics. Examples include the single-family detached home segment in the residential sector; and the office building segment in the commercial sector.

MJ	megajoule (= 10^6 Joule)
Mt	million metric tons
mtoe	million tons of oil equivalent
multi-project baselines	Emission baselines (also referred to as “benchmarks” or “activity standards” in the literature) that can be applied to a number of similar projects, *e.g.* to all electricity generation CDM or JI projects in the same country.
nameplate data	Data provided by equipment manufacturers that identify the make, model and performance characteristics of the equipment. These data are published in the manufacturer’s product literature and key data elements are affixed to the equipment on the nameplate. Often the equipment nameplate itself does not provide sufficient information for energy analysis.
N_2O	nitrous oxide
OECD	Organisation for Economic Co-operation and Development
off-peak load	The demand that occurs during the time period when the load is not at or near the maximum demand.
OHF	open hearth furnace
peak load	The maximum demand or load over a stated period of time. The peak load may be stated by category or period such as annual system peak, customer class peak, or daily peak.
peaking plants	Power plants normally reserved for operation during the hours of highest daily, weekly, or seasonal loads.
PJ	petajoule (= 10^{15} Joule)
PJe	petajoules electricity
PJp	petajoules calculated back to primary energy
PJf	petajoules final energy
Pozzolana	A natural cementious material that can be ground and used as a cement additive.
Process emissions	For cement production this refers to the CO_2 emitted from decarbonisation of limestone. It takes place during the pyro-processing step.
Production process change	Refurbishment of an existing plant that would change the process by which clinker is manufactured to a more efficient process (*e.g.* wet to dry, or semi-dry to dry)
Pyro-processing	This is the process of turning the raw materials into clinker (and takes place in the cement kiln).
Refurbishment projects	Projects in which existing equipment/processes are upgraded or replaced.

rpm	revs per minute
Run-time monitoring	Recording equipment or system runtime over a specific monitoring period. Often conducted with devices specifically designed for recording operating hours.
SAE	statistically adjusted engineering analysis
SEC	specific energy consumption
shaft kiln	The kiln, where clinker is produced, is vertical (whereas in other cement processes the kiln is slightly tilted, *e.g.* 1-3 degrees from the horizontal).
spot-watt measurements	One-time or instantaneous measurements of input wattage to a system or piece of equipment.
tcs	tonne of crude steel
thermal power plant	Power plants that burn fuel directly to produce steam.
TJ	terajoule (= 10^{12} Joule)
transaction costs	The costs associated with the process of obtaining JI or CDM recognition for a project and obtaining the resulting emission credits. Transaction costs would include, for example, costs of developing a baseline and assessing the “additionality” of a project, costs of obtaining host country approval, monitoring and reporting, *etc.* Transaction costs would not include the direct investment, maintenance and operational costs of the project.
UNFCCC	United Nations Framework Convention on Climate Change
update of baselines	Updating multi-project baselines, at regular intervals, in order to continue to reflect business-as-usual electricity investments. CDM or JI electricity projects would need to use the most recently updated multi-project baseline.
USAID	US Agency for International Development
USEA	US Energy Association
wet process	A process whereby the raw materials are ground, with water added, and mixed (as a slurry). The wet process is more energy-intensive than the dry process as energy is needed to evaporate the water in the raw material mix.

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