CLEAN DEVELOPMENT MECHANISM
PROPOSED NEW METHODOLOGY: BASELINE (CDM-NMB)
Version 01 - in effect as of: 1 July 2004

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SECTION A. Identification of methodology

A.1. Proposed methodology title:

"Baseline methodology for new capacity that displaces electricity generation in a centrally dispatched hydrothermal interconnected power system."

A.2. List of category(ies) of project activity to which the methodology may apply:

The UNFCCC has not provided a list of categories of project activities. Therefore, it is proposed to use the categories used for the accreditation of operational entities. Following this criterion, the category of project activity to which the methodology may apply is the Sectoral Scope 1 corresponding to "Energy industries (renewable / non-renewable sources)."

A.3. Conditions under which the methodology is applicable to CDM project activities:

The methodology is applicable to grid-connected renewable power generation project activities in a centrally dispatched hydrothermal electricity system, where there is an official source that provides a reference expansion plan, under the following conditions:

i) Applies to electricity additions and retrofits[1] from

- Hydro power plants;
- Wind sources;
- Geothermal sources;
- Solar sources;
- Wave and tidal sources.

ii) This methodology is not applicable to project activities that involve switching from fossil fuels to renewable energy at the site of the project activity, since in this case the baseline may be the continued use of fossil fuels at the site.

iii) The geographic and system boundaries for the relevant electricity grid can be clearly identified and information on the characteristics of the grid is available.

The baseline methodology shall be used in conjunction with the proposed monitoring methodology "Monitoring methodology for new capacity that displaces electricity generation in a

[1] For project activities that modify or retrofit an existing electricity generation facility, the guidance provided by EB08 shall be taken into account: "If a proposed CDM project activity seeks to retrofit or otherwise modify an existing facility, the baseline may refer to the characteristics (i.e. emissions) of the existing facility only to the extent that the project activity does not increase the output or lifetime of the existing facility. For any increase of output or lifetime of the facility which is due to the project activity, a different baseline shall apply." (EB08, Annex 1, http://cdm.unfccc.int/EB/Meetings/).

centrally dispatched hydrothermal interconnected power system," that is submitted with the present baseline methodology.

A.4. What are the potential strengths and weaknesses of this proposed new methodology?

Strengths:

- The use of a comprehensive and accurate numerical dispatch simulation for hydrothermal electricity grids allows to assess the extent to which hydro-electricity or thermal power is displaced with verification.
- The baseline methodology provides a way to determine real and measurable emission reductions.
- The methodology includes build margin effects into the operating margin calculation.
- The proposed methodology is able to deal with transmission constraints, taking into consideration transmission losses and bottlenecks that may require other non-dispatch-order power plants to operate in order to overcome physical constraints of the transmission system.

Weaknesses:

- The methodology relies on intensive input data.
- Running the simulation model periodically is a rather complex and time-consuming task.

SECTION B. Overall summary description:

Baseline emissions are calculated in a two-step procedure. First, the quantity of thermal electricity generation that is displaced by the project activity is determined with the help of a dispatch model. In the second step, emission reductions from avoided thermal power plants are calculated, applying emission factors of each power plant to the quantity of electricity generated by those plants. With the help of the dispatch model, it is possible to determine the amount of electricity replaced by the project activity and thus the saved GHG emissions.

A two-step approach is proposed to demonstrate additionality: a barrier analysis (step 1), complemented with a common practice analysis, and a financial analysis (step 2).

SECTION C. Choice of and justification as to why one of the baseline approaches listed in paragraph 48 of CDM modalities and procedures is considered to be the most appropriate:

C.1. General baseline approach:

☒ Existing actual or historical emissions, as applicable;

☐ Emissions from a technology that represents an economically attractive course of action, taking into account barriers to investment;

□ The average emissions of similar project activities undertaken in the previous five years, in similar social, economic, environmental and technological circumstances, and whose performance is among the top 20 per cent of their category.

C.2. Justification of why the approach chosen in 3.1 above is considered the most appropriate:

The methodology considers existing actual emissions from power plants connected to the grid.

SECTION D. Explanation and justification of the proposed new baseline methodology:

D.1. Explanation of how the methodology determines the baseline scenario (that is, indicate the scenario that reasonably represents the anthropogenic emissions by sources of greenhouse gases (GHG) that would occur in the absence of the proposed project activity):

To determine the baseline in this kind of projects, a sectoral analysis must be performed, taking into account national and sectoral policies and circumstances, and power system characteristics (e.g. expansion plans, planned sectoral reforms, etc.), in order to show that the continuation of current expansion plan is likely to occur. Thus the baseline scenario is the following: electricity would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources.

Baseline emissions in the hydrothermal electricity system are calculated using a standard numerical model, which takes into account all relevant information to simulate the system dispatch.

The baseline is determined by running the simulation model at the end of every year[2] during the crediting period in two cases:

1. Without including the proposed project activity into the system dispatch, under the expected expansion plan available at the time the project activity starts, i.e. including power plants considered in the expansion plan with the date they are likely to enter into operation, as foreseen in this plan for every year;
2. With the proposed project activity including the addition of new capacity that really occurs, i.e. new power plants and retrofits in the system are included using the date they have entered into operation every year.

In this way, build margin effects are taken into account within the operating margin calculation. In order to see how the presence of the project activity delays the onset of power plants considered in the expansion plan, this plan is not updated every year under case 1 above, leaving this update to the scenario that really happens in practice (case 2). This procedure is kept until the end of the period covered by the expansion plan. Beyond this period, the influence of the

[2] This is done to reduce uncertainty with respect to hydrological conditions, capacity additions, foreseen demand, and other input data of the dispatch model. In this way the numerical simulation provide more accurate results, since actual data will be load into the model.

presence of the project activity over decisions of other independent power producers is practically insignificant.

To estimate baseline emissions, official data are used. The national authority in charge of energy policy, in general, performs prospective analyses forecasting energy demand in order to foresee additional capacity requirements to cover unmet demand. These analyses are usually collected in a Reference Expansion Plan, which is used by agents in the electricity market for decision making. This plan also includes those capacity additions that form part of the projects declared to the energy authority.

Once the model is run, a specific approach to deal with baseline emissions is established. The methodology is applied according to a series of straightforward steps (see Section D.6 below), after first defining the project boundary (see Section D.5 below).

Characterization of a hydrothermal interconnected system

A hydrothermal interconnected system is composed by thermal and hydropower plants, which are dispatched according to a least-cost merit order, i.e. power plants in the electricity system are basically dispatched according to their marginal generation costs, but taking into account opportunity costs of water of hydropower plants with reservoirs that are able to store water from wet to dry seasons[3] and transmission constraints, such as transmission capacities or stability and reliability conditions, which modify actual dispatch with respect to the least-cost merit order.

There are two different types of power plant dispatch.

Ideal Dispatch

The generating companies that participate in the Wholesale Electricity Market have to submit price offers and availability in the energy market to the National Dispatch Center on a daily basis. Likewise, they have to report their generation units, per each hour for the next day, stating the variable generation costs they may incur in, considering the following:

- For thermal plants: the incremental cost of administration, operation and maintenance, the starting and stopping costs and the thermal efficiency of the plant, without considering the fixed costs of these.
- For hydroelectric plants: the opportunity costs (water value), assessed in relation to the future economic benefit of the company.

For hydroelectric plants, the water opportunity cost is considered instead of fuel cost. Therefore, companies should have adequate tools that would allow them to assess hydro resources able to be stored within a market context.

[3] Many times those plants are at the margin since they declare high costs of water, in a price-declaration competition. Nevertheless, even in these cases, thermal plants are displaced but differed on time.Thus, hidrological uncertainty becomes relevant in decision-making and a dispatch analysis performed on a daily basis can make non sense since it is unable to detect interseasonal variations that affect energy truly displaced.

Based on this price structure, an ideal dispatch is made without taking into account transmission system restrictions. The restrictions are economic surcharges that are present in the system as a consequence of limitations in the transmission grid, and which make it necessary to use generation plants that are more expensive than those used if such limitations were not present. Limitations can be (a) Electric: overload in lines or transformers due to thermal limits of this equipment, which produce limitations in the energy interchange among regions; or (b) Operational: voltage support, stability, reliability, trustworthiness, and frequency regulation, all of which allow maintaining quality in electricity service.

For these practical reasons, power generators that out-of-merit with the ideal dispatch may be called to generate. The ideal dispatch based on economic merits is used to obtain a marginal ideal price which, together with the marginal actual price and the prices offered by those generators that entered into the dispatch due to restriction reasons, permits calculating the payment to out-of-merit generators and the total additional costs due to restrictions in the system.

Actual Dispatch

An ideal dispatch cannot occur due to the conditions in the interconnected (national and/or regional) transmission system, which impose the so-called restrictions to the ideal dispatch, and therefore, generate actual dispatch. Typically some hydro plants that should have generated by merit in the ideal dispatch are displaced by out-of-merit thermal power plants, which have to generate due to grid restrictions. This situation arises since hydroelectric power plants are located where hydro resources are available, which are often far from load centers. Thermal power plants are often sited close to load centers and are thus less subject to grid restrictions. Out-of-merit thermal plants that are dispatched are paid according to their variable costs, which are, in general, above those of marginal hydropower plants. In brief, actual dispatch has the following cost structure: run-of-river plants (zero opportunity cost), then hydro plants with a dam (keep in mind that these plants include opportunity cost of stored water), then thermal plants, and lastly out-of-merit thermal and/or hydro, dispatched in order to cover restrictions.

The methodology provides a way for estimating what would have happened with the system dispatch in a situation that never occurs. This is too difficult due to interconnected system characteristics and dispatch rules. Therefore, the proposed methodology allows one to deal with this problem through a highly accurate procedure based on simulation model results.

Most of projects present this characteristic, but here the resulting emissions of that what would have happened in the absence of the CDM project activity are too difficult to correlate with actual measurable values of the main variables and parameters. Thus, this methodology correlates hypothetical results of the scenario representing that what would have happened in a very complex interconnected system with actual, real, and measurable values of that what really occurs in practice. This is the central point of the proposed methodology.

Minimum requirements of the simulation model

The model shall calculate the least-cost operational dispatch of a hydrothermal system, including restrictions, taking into account:

- Hydro plants operating characteristics (hydraulic balance, turbined outflow and storage limitations, safety volumes, spillage, filtration, etc.).

- Characteristics of thermal plants ("commitment", generation restrictions by group, cost curves, maintenance, fuel consumption, multi-fuel capability, gas pipeline restrictions, etc.).
- Historical series of annual hydrology, provided by the national meteorological center. The model shall be run every year in order to update baseline estimations and simulate the behaviour of the hydroelectric plant (with reservoirs) owners when deciding water storage according to market opportunity. This allows correlating water storage from one season to the other, according to rationing and agent decisions, accounting for the hydrological complementarity of the different basins of the country.
- Details of the transmission system: Kirchhoff laws, power flux limits in each circuit, losses, safety restrictions, export and import limits by electric area, etc.
- Demand variation by bar and by block of the system along monthly or weekly stages (mid- or long term-studies) or at hourly level (short-term studies), according to total demand occurred every year.

The model outputs are:

- Operating statistics: hydro and thermal generation, operating costs of thermal plants, energy exchange, fuel consumption, deficit risks and non-supplied energy for each stage at annual level; statistics are presented through averages, standard deviation, histograms, excess probabilities, minimum and maximum observed; results are presented by items (by demand block, by plant and by circuit) or aggregated at sub-system level (representing, for instance, a region or a company).
- Short-term marginal costs: these costs are used to represent purchasing and energy supply prices in the dispatch; statistics are presented through averages, standard deviation, minimum and maximum observed; results are presented by items (by demand block, by plant and by circuit) or aggregated at sub-system level (representing, for instance, a region or a company).
- Marginal capacity costs: these costs estimate the operating benefit of increasing the installed capacity of a thermal plant, the turbined outflow limitations of a hydro plant or the storage capacity of a dam, and they are used to determine the maximum profitability additions of a system.

The relevant outputs for estimating emissions in the without-project situation are the electricity generation of each power plant serving the interconnected system with their corresponding emission factors.

There are several models that can be used to simulate the dispatch able to meet the above mentioned conditions.[4]

D.2. Criteria used in developing the proposed baseline methodology:

[4] If available, the dispatch model should preferably be the model used by the dispatch center that manages the electricity system, in order to gain in accuracy, transparency and reliability (it will allow loading already verified input data in the numerical simulation). Otherwise, project participants shall justifiy why they decide to use other model.

The main criteria considered have been to maintain consistency among additionality, project boundary, baseline and monitoring, and the selection of an approach that represents a conservative way to deal with baseline and project emissions. It is justified in Sections D.6 and F below.

All calculations are transparent and all assumptions are explicit. The methodology allows obtaining emission reductions that are real and measurable as established in Article 12 of the Kyoto Protocol.

In a system with a significant share of hydropower generation, the electricity generation by the project activity affects electricity generation in the grid by both thermal and hydropower plants. Thus, the project activity may not only avoid electricity generation in thermal power plants, but also to a certain degree replace electricity from other hydropower plants. The dispatch model proposed here is able to reflect this and to calculate to which extent project electricity generation affects thermal and hydropower plants. An important advantage of the proposed approach is that this effect is not reflected in some other dispatch-analysis approaches for baseline determination developed so far, in hydrothermal systems with a high component of hydroelectric generation from hydropower plants with a reservoir. Moreover, the simulation is able to reflect specific conditions and constraints of the electricity system, such as hydrology or transmission constraints, which influence the economic dispatch of power plants.

D.3. Explanation of how, through the methodology, it can be demonstrated that a project activity is additional and therefore not the baseline scenario (section B.3 of the CDM-PDD):

A two-step approach is proposed to demonstrate additionality: a barrier analysis (step 1), complemented with a common practice analysis, and a financial analysis (step 2).

Step 1: Analysis of existing barriers to the proposed project activity.

The barriers are those that prevent the project activity to be carried out. These barriers can be:

a. Investment barrier (lack of investment resources),
b. Technological barrier (existence of risks associated with performance of new technology),
c. Barrier due to low penetration (existence of technologies with higher market penetration),
d. Barrier due to prevailing practice (existence of a different prevailing technological option),
e. Regulatory barrier (existence of subsides to other alternatives or regulation that imposes project to be developed as the proposed project activity does),
f. Competitive disadvantage barrier (existence of traditional projects with competitive advantages over the project itself),
g. Other justifiable barriers to be judged by the DOE (institutional [long-lasting instability of political or economic conditions of the country discouraging investment], sectoral [policy reforms discouraging project implementation or deregulation of the electricity market discouraging renewables or uncertainties related to capacity charge values, fuel prices and availability, security, hydrology, etc.], social [rural community refusal to large undertakings or guerrilla attacks to transmission lines in rural areas], etc.).

Other barriers, such as information, organizational, cultural, lack of capacity to absorb new technologies, or limited managerial resources to comply with energy and emission standards, are excluded from this analysis, since the methodology applies to countries with a developed electricity market structure able to provide and handle basic information required to run the simulation model. Barriers due to temporary or circumstantial facts should be excluded since projects are thought to be long-term sustainable activities.

Documented evidence shall be provided in order the DOE can objectively judge the relevance of these barriers and how they prevent the implementation of the project activity. This documentation should be enough to determine whether the project activity would have occurred in the absence of CDM registration or not.

Finally, it needs to be shown that any of these barriers prevents the continuation of current expansion plan.

Step 2: Financial analysis.

An analysis of two financial indicators could be made in order to show that the proposed project activity is neither an economically attractive course of action by itself nor in relation to other alternatives (potential baseline scenarios other than the continuation of current expansion plan, which has not any financial hurdless or risk). The financial indicators are net present value (NPV) and internal rate of return (IRR). A country-specific discount rate or the one used by the project sponsor (if properly justified) should be used to compare with IRR. The proposed project activity is not the baseline if (a) NPV is negative and/or (b) IRR is below the country or sponsor discount rate, and/or (c) IRR is lower than IRR of at least one of other alternatives (viable or not), and/or NPV and IRR are worst than those of an attractive course of action (e.g. a natural gas combined cycle power plant).

Project investment as well as investment needs of other alternatives should be compared in order to see the behaviour of this relevant decision parameter, namely investment.

D.4. How national and/or sectoral policies and circumstances can been taken into account by the methodology:

When analyzing additionality issues sectoral and national circumstances must be taken into account, because they are key elements to understand the environment in which the project is going to be developed. These are matters to be considered under a project-specific basis. In general, the methodology addresses these circumstances by taking into account energy demand, capacity expansions, sectoral activity levels, system characteristics and electricity trends, regulatory framework, sectoral policies and other specific legislation determining system functioning, standard official data used as input modeling data, etc.

D.5. Project boundary (gases and sources included, physical delineation):

According to the baseline assumptions and additionality issues, the project boundary accounts for the physical location of the project activity, including emission sources under the control of the project participants.

1) Project participants shall account only the following **emission sources** for the project activity:

- For geothermal project activities, fugitive emissions of methane and carbon dioxide from non-condensable gases contained in geothermal steam and carbon dioxide emissions from combustion of fossil fuels required to operate the geothermal power plant.
- For hydroelectric power plants, methane emissions generated as a consequence of organic matter decomposition in flooded areas by the project.

For the baseline determination, project participants shall only account CO_2 emissions from electricity generation in fossil fuel fired power that is displaced due to the project activity.

2) The **spatial extent** of the project boundary includes the project site and all power plants connected physically to the electricity system that the CDM project power plant is connected to.

Electricity transfers from connected electricity systems to the project electricity system are defined as **electricity imports** and electricity transfers to connected electricity systems are defined as **electricity export**s.

For the purpose of determining the Operating Margin (OM) emission factor, as described below, use one of the following options to determine the CO_2 emission factor(s) for net electricity imports ($COEF_{i,j,imports}$) from a connected electricity system within the same host country(ies):

(a) 0 tCO_2/MWh, or
(b) the emission factor(s) of the specific power plant(s) from which electricity is imported, if and only if the specific plants are clearly known, or
(c) the average emission rate of the exporting grid, if and only if net imports do not exceed 20% of total generation in the project electricity system, or
(d) the emission factor of the exporting grid, determined as described in steps 1, 2 and 3 below, if net imports exceed 20% of the total generation in the project electricity system.

For imports from connected electricity system located in another country, the emission factor is 0 tons CO_2 per MWh.

Electricity exports should not be subtracted from electricity generation data used for calculating and monitoring the baseline emission rate.

The baseline establishes which are the emissions that would have occurred without the project implementation but only associated with it, not to the whole system. Thus, if the project were not implemented what would be about to be emitted is only the proportional part to the one that would be covered by the project, i.e. emissions associated with the displaced thermal electric energy in the system (not necessarily at the margin, since there are restrictions in the system) due to the project activity.

No significant leakage is expected for this kind of projects. Some of the eventual indirect effects outside the project boundary are actually considered under the simulation of the power plants dispatch, since any rearrangement or change that could occur due to the project activity is under the market conditions simulated by the model. Other potential source of leakage could be the increase in the energy demand in the region where the project operates due to the development of energy-intensive activities, but it is precisely one of the sustainable development contributions of the project activity and it is disregarded as leakage in this methodology. Any other measurable net change of anthropogenic GHG emissions by sources that occurs outside the project boundary and reasonably attributable to the CDM project activity shall be accounted for.

D.6. Elaborate and justify formulae/algorithms used to determine the baseline scenario. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

The baseline is supposed to be applied to electricity generation projects in centrally dispatched interconnected hydrothermal systems, under the assumption that the project displaces a portion of thermal energy that would have been delivered by other thermal plants serving the system in the absence of the proposed project activity.

The following steps identify the baseline methodology.

Step 1

Collect data needed to run the simulation dispatch model. These data are obtained from verifiable and/or official sources. National and sectoral circumstances influencing the baseline are included in this step, gathering information on characteristics of the interconnected electricity system, historical trends and activity levels, capacity expansion plans, prospective analyses on future electricity demand, fuel prices, unavailability of generation plants and transmission lines, programmed maintenance activities, energy reserves, historical hydrology, scenario analysis under political and economic trends of the sector and the country, relevant data for estimating emission factors (net calorific values, physical properties and chemical composition of fuels, specific emission factors for fuels used in the local industry, efficiencies, etc.). See Section E.2 and step 3 below.

Step 2

Estimate the power plant emission factors per unit of generated energy for the fuel f, based on local or national data and eventually using default values from international sources (IPCC, International Energy Agency, etc.). The already collected necessary data in step 1 is going to be used in this step. Equation (D.6.1) proposes an alternative way of estimating the emission factors, $ef_{n,f}$, corresponding to each thermal power plant centrally dispatched in the interconnected system.

$$ef_{n,f}\,(tonne\ CO_2\ /\ GWh) = sc_{n,f}\,(ktonne\ fuel\ /\ GWh) \times EF_f\,(tonne\ CO_2\ /\ TJ) \times LHV_f\,(TJ\ /\ ktonne\ fuel) \times OF_f \qquad \text{(D.6.1)}$$

where $sc_{n,f}$ is the specific consumption of the plant n for the fuel f, EF_f is the carbon dioxide emission factor of the fuel f, and LHV_f is the lower heating value of the fuel f. These factors are adjusted for incomplete combustion, OF_f, taking into account combustion efficiency default values for the different fuels burned in thermal power plants. Other alternatives can be used, depending on the initial data that can be obtained. In the absence of reliable base information, IPCC default values should be used, from the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories.

Emission factors are going to be recalculated every time there are relevant changes in the power plants of the electricity grid (e.g. due to efficiency improvements, retrofits, inclusion of new plants, plant shutdown, fuel substitution, power capacity redefinition, etc.) and the information is available. These emission factors shall be revised every year, when the dispatch model is re-run.

Step 3

Load input data into the software platform to run the simulation model. These data include, among others (see a complete set of parameters in Section E.2 below):

a. Configuration and topology of the power plants belonging to the interconnected system and operating data. This includes technical data of the power plants and the system; identification of the centrally dispatched power plants; specific technology; nominal and net capacity; water flow, production factor and storage capacity of hydro plants; fuel efficiencies and specific consumption of thermal plants; bar and load data of the transmission lines; etc. (Section E.2 deals with these data in more detail).
b. Historical hydrology of the year for which the simulation is run.
c. Electricity demand of the year for which the simulation is run.
d. Load curve discriminated in five hourly demand blocks.
e. Annual distribution of new plants according to the Reference Expansion Plan prior to project implementation (for the simulation without the project activity, step 5 below) and actual additions to the system (for the simulation with the project activity, step 6 below).

Step 4

Build margin: In order to determine the influence of the project in investment decisions and the impact it causes delaying the construction of new power plants, the following approach applies.

Sub-step 4.1.1. Identify and list the power plants that are going to enter into operation for every year during the period covered by the expansion plan.

Sub-step 4.1.2. Set the date of entering into operation of the power plants listed in sub-step 4.1.1 (according to the dates established in the expansion plan), which will remain fixed for the entire period covered by the expansion plan. That is, every year when the dispatch model is run, the above listed set of plants will be loaded into the simulation (under the assumption that they belong to the sceanrio that would have occurred in the absence of the porject activity). Actual evolution of the system additions should reflect the delay introduced by the presence of the proposed project activity. This is a conservative assumption, because the situation that will typically happen in practice is that power plants are actually delayed more time than the one expected to occur due to

build margin effects. In that case, the baseline is including more efficient power plants (under the logical assumption that the expansion plan is tending to increase efficiency of the system). Therefore, baseline emissions are lower than those that would have been ocurred, thus lowering emission reductions of the project. Otherwise, build margin effects would have been not relevant at all, but even in this case the approach is conservative.

Operating margin:

Step 5

Run the simulation model without including the project and considering the latest expansion plan published just prior[5] to project implementation. The additions considered in this expansion plan will be fixed and used for running the dispatch model every year, during the period covered by the expansion plan. After the end of this period, the simulation shall be run with the power plant system composition that have occurred every year (the same used for the simulation that includes the project).

Step 6

Run the simulation model including the project and the capacity additions that have occurred during the year that is used in the *ex post* simulation. This procedure shall be repeated every year during the crediting period.

Step 7

Gather the outputs (daily power plants generation, $\tilde{g}_{n\pm}$, where "+" stands for the simulation with the project and "–" without the project) in order to estimate relevant emissions from steps 5 and 6, formatted in MS Excel files on a monthly and yearly easily-to-handle basis. Here, "~" stands for variables estimated through the simulation model, to distinguish them from the same variables obtained in real conditions.

This step can be considered the first step of the methodology after running the simulation model (the model is an already sound computer program, and only input and output are relevant).

Step 8

Calculate annual emissions of thermal power plant n, $\tilde{e}_{n+}$, for the simulation performed in step 6.

$$\tilde{e}_{n+}(tonne\ CO_2\ /\ year) = \sum_f \tilde{g}_{n+,f}\ (GWh\ /\ year) \times ef_{n,f}\,(tonne\ CO_2\ /\ GWh) \qquad \text{(D.6.2)}$$

where $\tilde{g}_{n+,f}$ is the electricity generated by the thermal power plant n in a year, while consuming the fuel f (in case that more than one fuel is consumed by the power plant n).

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[5] This plan can be the most recent expansion plan published by an official and reliable source (e.g. a government agency), but not beyond the last two years (i.e. a project activity that starts operation in 2006 shall use the latest expansion plan, which could be the one corresponding to the years 2004, 2005, or 2006).

For the sake of simplicity, from now on it goes without saying that different fuels can be involved in $\tilde{g}_{n+}$.

Step 9

Calculate total CO_2 emissions per year, $\tilde{E}_{+}^{(th)}$, of the thermal power plants serving the system from results derived in step 8.

$$\tilde{E}_{+}^{(th)}\,(tonne\ CO_2\,/\,year) = \sum_{n=1(th)}^{N} \tilde{e}_{n+}\,(tonne\,CO_2\,/\,year) \qquad \text{(D.6.3)}$$

where N is the number of thermal plants in the system and the sum extends only over thermal (*th*) plants.

Step 10

Calculate the total amount of thermal electricity generated in a year, $\tilde{G}_{\pm}^{(th)}$, from results of steps 5 and 6 (with (+) and without (–) the project).

$$\tilde{G}_{\pm}^{(th)}\,(GWh\,/\,year) = \sum_{n=1(th)}^{N} \tilde{g}_{n\pm}\,(GWh\,/\,year) \qquad \text{(D.6.4)}$$

Step 11

Obtain the annual average CO_2 emissions, $\langle \tilde{E} \rangle_{+}$, of the thermal plants serving the system, combining steps 9 and 10.

$$\langle \tilde{E} \rangle_{+}\,(tonne\ CO_2\,/\,GWh) = \tilde{E}_{+}^{(th)}\ (tonne\ CO_2\,/\,year)\ /\ \tilde{G}_{+}^{(th)}\ (GWh\,/\,year) \qquad \text{(D.6.5)}$$

Step 12

Calculate the thermal generation displacement factor, $\tilde{F}$, as the rate between the difference of the energies obtained in step 10 (‘without the project’ minus ‘with the project’) over the energy generated by the project itself.

$$\tilde{F} = \frac{\tilde{G}_{-}^{(th)} - \tilde{G}_{+}^{(th)}}{\tilde{g}_{P}} \qquad \text{(D.6.6)}$$

$\widetilde{F}$ is the only parameter obtained from simulation model results. It allows one to correlate emissions, when the power system includes the proposed project activity, with those that would have occurred in the absence of the proposed project activity. $\widetilde{G}_{+}^{(th)}$ and $G_{+}^{(th)}$ as well as $\widetilde{g}_P$ and g_P shall be compared during monitoring in order to decide whether $\widetilde{F}$ remains realistic.

Step 13

Calculate baseline emissions.

Baseline emissions are defined as:

$$E_B \equiv g_P \times \langle \widetilde{F} \rangle \times \langle E \rangle_{+} \quad \text{(D.6.7)}$$

The last equation is the key equation of the proposed methodology. It reads: baseline emissions represent the amount of thermal plant emissions displaced by the project activity, where $\langle \widetilde{F} \rangle$ accounts for the fraction of this thermal energy with respect to the energy generated by the project; $\left(1 - \langle \widetilde{F} \rangle\right)$ is the hydroelectric energy displaced by the project. Moreover, $\langle \widetilde{F} \rangle \times \langle E \rangle_{+}$ can be considered as a system emission factor, $\langle E \rangle_{sys}$, which includes part of the hydroelectric contribution. Every year a new value of $\langle \widetilde{F} \rangle$ is calculated running the simulation model again to update results with actual data. This is an important step since hydrothermal systems with reservoirs storing water for use during dry seasons alter the marginal dispatch by shifting thermal emissions and thus making unviable an estimation of emission reductions as that achieved by displacing marginal plants on a hourly or daily basis. The simulation model itself provides reliable outputs when considering the long-term behaviour of the hydrothermal system. This is one of the main characteristics of the systems to which the methodology applies.

Recall that $\langle \widetilde{F} \rangle$ is different from 1 because a part of the displaced energy generation is also hydroelectric, due to the value of water and consequent storage by hydropower generators, implying that some hydro plants are at the margin (this is one of the main characteristics of a hydrothermal interconnected system), and also because a part of thermal energy cannot be displaced due to transmission capacity limitations.

No ~ is written in $\langle E \rangle_{+}$ and g_P since they are calculated in actual conditions. $\langle \widetilde{E} \rangle_{+}$ and $\widetilde{g}_P$ are only used from the model in order to perform the first estimation of baseline emissions, but not for monitoring purposes.

The factor $\langle \widetilde{F} \rangle$ includes the information about the situation that would occur without implementing the proposed project activity. But this situation never happens in reality, then the methodology, Equation (D.6.7), provides a way to estimate avoided emissions due to the project activity, monitoring *ex post* variables and fixing a parameter. The advantage of this formulation is motivated by the fact that, under actual conditions, it is not possible to obtain power plant generation, g_{n-} (since they can only be estimated through the simulation model). The parameter

fixed through the simulation has less sensitivity to variations in real conditions, since $\langle \tilde{F} \rangle$ is based on the difference between correlated scenarios (under the same assumptions and input data).

Running the simulation model again, after actual conditions have happened every year, allows obtaining more accurate baseline emissions, but nevertheless depending on the simulation of a situation that does not happen in reality but that can be strongly correlated to actual conditions regarding hydrology, demand, and system capacity.

Output results can be obtained in a daily, monthly, or yearly basis. It is recommended to use a monthly basis –to save disk space– and thus combining these data to obtain annual values. This completes the overall description of the proposed baseline methodology steps.

To improve accuracy the simulation model shall be re-run every year based on updated data.

D.7. Elaborate and justify formulae/algorithms used to determine the emissions from the project activity. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

Project emissions

For most renewable energy project activities, project emissions are zero, $E_P = 0$.

a) Methane emissions due to biomass decomposition in flooded areas for hydroelectric project activities:

Because some controvery remains over this issue, mainly as a consequence of disregarding the project scale into the discussion, an extremely conservative assumption is proposed, consisting of bounding methane emissions by an upper limit extracted from literature.

For example, Hydro Québec[6] has collected information from several serious studies and provide methane emission factors for different kind of power plants in terms of electricity output, when the so-called life-cycle assessment is carried out, including emissions from fuel extraction, processing and transportation, as well as from power plant construction and electricity generation. The result obtained by applying this proposal must be compared with other already suggested approaches and with emissions one step upstream estimated independently in a more direct way.

The annual average methane emissions corresponding to the flooding of the reservoir (E_{Pf}) can be estimated by:

$$E_{Pr} \text{ (tonne } CO_2\text{e/year)} = g_P \text{ (GWh/year)} \times ef_P \text{ (tonne } CO_2\text{e/GWh)} \qquad \text{(D.7.1)}$$

[6] Greenhouse Gas Emissions from Power Generation Options, by Luc Gagnon, Hydro Québec (January 2003). http://www.hydroquebec.com/environment.

This methodology proposes to use the World Bank approach,[7] whereby methane emissions can be estimated from equation (D.7.2), below. Hydro Québec values can be optionally considered as a cross check.

Flooding of land due to the construction of hydroelectric dams and reservoirs, construction or preservation of wetlands, or other land-use activities results in emissions of CH_4 generated by the anaerobic decomposition of (1) vegetation on the flooded land, (2) vegetation that re-grows in the water, dies, and settles to the bottom, and (3) soil carbon.

Methane emissions from the flooding of land are calculated as the product of (1) the area of land to be flooded, (2) the number of days per year that the land is flooded, and (3) an average daily CH_4 emission rate. This rate, expressed in units of mg CH_4-C/m^2-day, varies according to land type, climate, and duration of flooding.

Annual emissions of methane are calculated according to equation (D.7.2). As explained above, in spite of the fact that the flooded area does not give rise to organic matter decomposition, a precautionary value is even reported.

Area of Flooded Land	×	Duration of Flooding	×	Average Daily CH_4 Emission Rate	×	Conversion Factor	×	Molecular/ Atomic Weight Ratio	=	Annual CH_4 Emissions Produced
(m^2)		(days/year)		(mg CH_4-C/m^2-day)		(tonne/mg)		(tonne CH_4/ton CH_4-C)		(tonne CH_4/year)

Estimation of methane emissions from land flooding (D.7.2)

b) Fugitive emissions of CH_4 and CO_2 for geothermal[8] project activities:

For geothermal project activities, project participants shall account the following emission sources,[9] where applicable:

- Fugitive emissions of carbon dioxide and methane due to release of non-condensable gases from produced steam; and
- Carbon dioxide emissions resulting from combustion of fossil fuels related to the operation of the geothermal power plant.

The data to be collected are listed in the associated monitoring methodology, ACM0002. Project emissions should be calculated as follows:

[7] Greenhouse Gas Assessment Handbook, A Practical Guidance Document for the Assessment of Project-level Greenhouse Gas Emissions, Paper Nº 064, Sept. 1998, The World Bank.
[8] This type of project activities shall refer to ACM0002, from which the current procedure was extracted.

[9] Fugitive carbon dioxide and methane emissions due to well testing and well bleeding are not considered as they are negligible.

a) **Fugitive carbon dioxide and methane emissions due to release of non-condensable gases from the produced steam *(E_{Ps})*:**

$$E_{Ps} = \left(w_{Main,CO_2} + w_{Main,CH_4} \cdot GWP_{CH_4}\right) \cdot M_S \qquad \text{(D.7.3)}$$

where E_{Ps} are the project emissions due to release of carbon dioxide and methane from the produced steam during a given year, w_{Main,CO_2} and w_{Main,CH_4} are the average mass fractions of carbon dioxide and methane in the produced steam, GWP_{CH4} is the global warming potential of methane and M_s is the quantity of steam produced during a given year.

b) **Carbon dioxide emissions from fossil fuel combustion *(E_{Pf})***

$$E_{Pf} = \sum_i F_i \cdot COEF_i \qquad \text{(D.7.4)}$$

where E_{Pf} are the project emissions from combustion of fossil fuels related to the operation of the geothermal power plant in tons of, F_i is the fuel consumption of fuel type *i* during a given year and $COEF_i$ is the CO_2 emission factor coefficient of the fuel type *i*.

Thus, for geothermal project activities,

$$E_P = E_{Ps} + E_{Pf} \qquad \text{(D.7.5)}$$

D.8. Description of how the baseline methodology addresses any potential leakage of the project activity:

No leakage is perceived to occur under this approach.

D.9. Elaborate and justify formulae/algorithms used to determine the emissions reductions from the project activity. Variables, fixed parameters and values have to be reported (e.g. fuel(s) used, fuel consumption rates):

Emission reductions are given by:

$$ER = E_B - E_P = g_P \times \langle \widetilde{F} \rangle \times \langle E \rangle_+ - E_{Pr} - E_{Ps} - E_{Pf} \qquad \text{(D.9.1)}$$

Baseline emissions are given by Eq. (D.6.7) and project emissions are given by Eq. (D.7.2) for methane emissions from flooding and Eq. (D.7.5) for GHG emissions from geothermal plants.

SECTION E. Data sources and assumptions:

E.1. Describe parameters and or assumptions (including emission factors and activity levels):

The first set of key parameters is the one associated with input data to be loaded within the dispatch model.

Most necessary data must be provided by the manager of the wholesale electricity market or the government department in charge of dispatch decisions (the national dispatch centre or a similar body). In general, in centrally dispatched interconnected systems the data are loaded by those responsible for dispatch from information supplied by market operators (**generators**: *e.g.* power plant configurations and operating data, **transmission companies**: *e.g.* transmission line interconnections and grid arrangement, and **distributors**: *e.g.* contractual agreements). Other data are provided by national or regional centres taken as official sources, which in turn collect data from involved companies (e.g. fuel providers from which fuel costs are registered, hydrological stations or national or regional meteorological office from which hydrology is accounted for, etc.). There is no unique rule to collect necessary data, but some recommendations are in order. These are mainly related to finding the way to access the database handled by the manager of the power plant dispatch. Usually, all generators have access to this information, which is an important part of their usual practice, since they need to know how to be prepared for delivering and selling electricity to the system. If this were not the case, the methodology would be too hard to apply. Fortunately, however, running simulation models to forecast power plant dispatch is a standard procedure most generators usually perform.

The set of key parameters depends on the particular simulation model to be used. Some of these parameters are configuration of hydroelectric plants (topological, operating, and activity data), configuration of thermal plants (operating and activity data, fuel characteristics, consumption, and prices), hydrology (inflow records), load (based on demand, reserves, and constraints), transmission (grid configuration model), and contractual data (PPAs).

Besides the parameters used as input data for the simulation model the other key parameters are those related to emissions calculation. Specifically, generation of thermal plants, g_{n+}, generation of the project g_P, and emission factors of thermal power plants $ef_{n,f}$ (n labels power plants and f fuel consumed). For the latter, lower heating values of fuels used, LHV_f, fuel emission factors, EF_f, for carbon dioxide, methane and nitrous oxide, and specific consumptions of thermal power plants, $sc_{n,f}$, are needed to estimate GHG emission factors. In some cases, physical properties and chemical composition of the fuels may be required or occasionally annual fuel consumption of the thermal plants. It depends on the manner relevant data are collected from available sources.

Activity levels are those related to electricity generation of the thermal plants serving the system and the project itself; other parameters are already included in the modelling input data (projected demand, system expansion, fuel prices, generation costs, etc.).

From the environmental impact point of view, water quality is an important parameter to be periodically monitored, as well as other relevant indicators, such as those related to social and economic development of the region in which the project operates.

Key factors associated with emissions from transportation of material and people in the construction phase, and methane released from reservoirs can also be expressed in terms of the emission factors of fuels and flooded areas, respectively. Because the corresponding emissions are usually very small, adequate data source include the National GHG Inventory and default emission factors, such as those compiled in the Revised 1996 IPCC Guidelines for Greenhouse Gas National Inventories. These factors are key parameters of the project and not the baseline and they are included here for the sake of completeness.

E.2. List of data used indicating sources (e.g. official statistics, expert judgement, proprietary data, IPCC, commercial and scientific literature) and precise references and justify the appropriateness of the choice of such data:

Table E.2.1 summarizes the key parameter information associated with modeling input data.

Table E.2.1: modeling input data

Topic / Parameter	unit	Data source
Projected annual energy demand of the electricity system	GWh/year	1. Ministry of Energy 2. Dispatch Center 3. National statistics
Expansion plan including: macroeconomic projections, sectoral policies, fuel costs, energy demand and electricity capacity, occurrence of El Niño type phenomenon, recording of generation projects, reliability criteria established for planning, transmission grid, unavailability of generation units and of transmission lines, energy reserves, hydro contribution		1. Ministry of Energy 2. Dispatch Center 3. National statistics
Demand blocks	Number (#) Duration (%, hours)	1. Project sponsor 2. Dispatch Center
Rationing costs	Segment (%) Cost ($/MWh)	1. Dispatch Center 2. Project sponsor
Discount rate	%	1. Project sponsor 2. National statistics

The energy demand and the expansion plan are considered to estimate baseline emissions *ex ante*. Nevertheless, since the model will be run every year, when actual conditions are in place, these data will be updated, and actual expansion of the system together with the original fixed plan are going to be used in estimating baseline emissions for the next year.

Table E.2.2 summarizes the key parameter information associated with activity levels. This set of key parameters contains the input data for the simulation model that can be verified by a Designated Operational Entity (DOE) in order to validate the results coming out of the model. The DOE can verify that data are adequately handled by the entities (acting as data sources)

providing relevant information, as to determine, for example, emission factors of power plants serving the system and their update, the reliability of dispatch center database, etc.

Table E.2.2: activity level parameters

Parameter	unit	Data source
Project generation: g_P	GWh	1. Project sponsor 2. Dispatch Center
Generation of power plants serving the system: g_n	GWh	1. Dispatch Center 2. Generators 3. National statistics
Specific consumptions of power plants serving the system for the fuel f: $sc_{n,f}$	tonne (coal) or m^3 (natural gas) or l (liquid fuels) / GWh	1. Dispatch Center 2. Generators 3. Electricity distributors
Lower heating value of fuel f: LHV_f	TJ/ktonne fuel	1. Dispatch Center 2. Ministry of Energy 3. Fuel distributors

Regarding emission factors the key parameters are summarized in Table E.2.3.

Table E.2.3: emission factors key parameters

Fuel	GHG	Source	Variable name	Emissions factor	Data sources (No. indicates data priority: No. 1 is best, if data not available, choose No. 2, and if not available, choose No. 3)
Coal, NG, Diesel, Fuel oil, other	CO_2	Combustion	CEF_f, f=fuel	kg CO_2 per GJ LHV basis	1. National GHG inventory 2. IPCC, fuel type and technology specific 3. IPCC, near fuel type and technology
	CH_4	Combustion	MEF_f, f=fuel	kg CH_4 per TJ LHV basis	1. National GHG inventory 2. IPCC, fuel type and technology specific 3. IPCC, near fuel type and technology
	N_2O	Combustion	NEF_f, f=fuel	kg N_2O per TJ LHV basis	1. National GHG inventory 2. IPCC, fuel type and technology specific 3. IPCC, near fuel type and technology

Finally, specific key parameters to estimate project emissions (methane emissions from flooding and CO_2 emissions from transport), are considered in Table E.2.4. These data is going to be provided by the project sponsor.

Table E.2.4: other specific project parameters

Parameter	unit	Data source
Area of flooded land	m^2	Project sponsor
Duration of flooding	days/year	Project sponsor
Project capacity factor	%	Project sponsor
Methane emission factor from reservoirs	tonne CO_2e/GWh	1. Hydro Québec 2. World Commission on Dams
Daily methane emission rate	mg CH_4-C/m^2-day	UNEP/OECD/IEA/IPCC (1997)
Fuel consumption of vehicles and machinery	l	Project sponsor
Fuel emission factor	g/kg fuel	1. National GHG inventory 2. IPCC, 1996 Revised Guidelines

E.3. Vintage of data (e.g. relative to starting date of the project activity):

The vintage of data is established in the monitoring plan compatible with the monitoring methodology. The results derived from the simulation model shall be archived for two years following the end of the crediting period. Emission factors, input data of the model, and data obtained from national sources shall be updated every year.

E.4. Spatial level of data (local, regional, national):

Most data are given at a national level. Only specific consumptions of fuel by power plants can be sometimes obtained from local sources (the own generators), and fuel characteristics can be obtained from regional sources (fuel distribution companies).

SECTION F. Assessment of uncertainties (sensitivity to key factors and assumptions):

There are two categories of uncertainties in this methodology. Because a software is involved, there are standard uncertainties addressed by the software developers, related to the input data handled to run the simulation model.

The other type of uncertainties is related to variables and parameters used to determine baseline and project emissions after model outputs are obtained.

Handling simulation model uncertainties:
In the first case, the model is sufficiently flexible to be adapted to particular needs of project specific matters. It permits the calculation of standard deviations of the relevant variables under manipulation and one can introduce the level of uncertainty and error margins of the input data loaded before running the computational algorithm.

Since several data are going to be provided by the entity responsible of managing the system dispatch or a governmental agency, some level of confidence is needed and error bars can be assumed by project developers under reasonable and justifiable hypotheses.

The proposed baseline methodology accounts for the most relevant variables.

Water valuation: from a theoretical point of view, the value of stored energy in reservoirs is obtained as an avoided future cost, which is associated with the avoided thermal cost in interconnected hydrothermal systems (avoided rationing cost). This valuation assumes that all operators have the same perception of the hydrological risk and that the rationing cost would be absorbed by generators if they did not supply the associated energy. This is not necessarily what happens in reality, so that modelling is handling some subjective rules which add uncertainty to the generated outputs. But it is one of the core assumptions of the simulation model and it is hard to minimize it on a theoretical basis.

Short-term marginal cost: the model assumes that power plants are dispatched according to least-generation variable costs in a perfect competitive market, i.e. the selling price of electricity is equal to the cost of the marginal generator. But it depends on how many actors dominate the market.

Long-term contracts: the opportunity cost of long-term contracts are key decision elements for generators. This adds another share of uncertainty in a least-generation-cost modelling of the electricity system.

Hydrology: it is based on historical patterns and then stochastically simulated. Reality will determine what conditions actually occur. Thus, stochastic series have been proposed as the best way to deal with hydrological uncertainties. Stochastic series of flows are time-dependent series constructed from a stochastic variable but preserving the mean value and the standard deviation of the reference historical series. Monthly flow series are adjusted by a Normal frequency distribution, where values are within the standard deviation interval around the mean values. The model should provide mean values and standard deviations. Historical series are updated every year minimizing uncertainties.

In spite of these difficulties, it must be remembered that electricity agents in the market, mainly hydroelectric generators, base their decisions using the same tools as the one proposed here, that is to say, running a simulation model, so that they offer their energy resources against the same backdrop.

Output data: the output data useful for estimating GHG emissions are thermal plant generation. These variables are calculated as mean values with their standard deviations. From these data, error propagation can be applied to determine error intervals.

Uncertainties associated with baseline and project emissions calculation:

- ***Baseline***:

- *Project generation*: The main uncertainty is the one related to measurement devices. The monitoring plan includes procedures to avoid systematic errors and to obtain reliable data.
- *Emission intensity of the grid*: This is obtained mainly from public data originally provided by many different agents. It is expected that errors of one or more generators compensate errors of other generators, so that in average data are reliable. However, these data are continuously audited since business decisions are strongly dependent of them, thus guaranteeing a low level of uncertainty.

- *Displaced thermal electricity*: Uncertainties are increased along time, due to the difficulty in predicting hydrology (especially in tropical and subtropical regions, where a high climate and rainfall variability exists), electricity demand (especially in countries with unstable economies sensitive to political circumstances), expansion capacity of the system (especially in countries with severe investment and debt problems), etc. The actual interconnected grid is a very complex dynamic system, so that it is too difficult to reduce uncertainty through model manipulation. The way to deal with this high level of uncertainty is to run the model every year after actual conditions are already known. In this way, demand, capacity additions, and a part of hydrology (only the previous year) will be updated and whereby under the control of the simulation model operator. Deviations of the thermal displacement factor can reach up to 20% with corresponding impact on final baseline emissions, since these emissions only depend on such a factor as the unique parameter to be determined exclusively from simulation. Baseline emissions estimations can have larger deviations. Monitoring procedures also reduce the level of uncertainty since project generation and emission intensity of the grid are obtained from actual data and by running the model again every year the thermal displacement factor shall be obtained on a more reliable basis from updated data for the following years.

- ***Project***:

- *Reservoir*: The main uncertainties come from the lack of a precise theory of methane emissions from flooded areas. The scientific literature shows that reservoirs can emit methane and carbon dioxide due to the anaerobic decomposition of biomass. The main scientific controversy centres on the extrapolation of measured emissions per m^2 in selected parts of the reservoir to the whole reservoir area. Emissions almost certainly vary according to depth and the distribution of the submerged biomass. They also vary through time, with a rapid peak occurring shortly after submersion after which they tail off at an unknown rate. Studies have not yet been carried out over long periods to characterize the full life-cycle curve of the emissions.[10]

  In order to handle uncertainties associated to methane emissions from the reservoir, a comparison is made with data taken from other sources, which use a different accounting approach, e.g. Hydro Québec.[11] It allows setting an upper bound to those emissions.

SECTION G. Explanation of how the baseline methodology allows for the development of baselines in a transparent and conservative manner:

The main criteria considered were the consistency among additionality, project boundary, baseline and monitoring, and the selection of an approach that represents a conservative way to deal with baseline and project emissions. It was justified in Sections D.6 and F above.

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[10] WCD Thematic Review II.2 Environmental Issues, "Certainty and Uncertainty in the Science of Greenhouse Gas Emissions from Hydroelectric Reservoirs," by L. Pinguelli Rosa and M. A. dos Santos, March 2002. World Commission on Dams (http://www.dams.org).

[11] Greenhouse Gas Emissions from Power Generation Options, by Luc Gagnon, Hydro Québec (January 2003). http://www.hydroquebec.com/environment.

All calculations are transparent and all assumptions are explicit. The methodology allows obtaining emission reductions that are real and measurable as established in Article 12 of the Kyoto Protocol.

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