CLEAN DEVELOPMENT MECHANISM
PROJECT DESIGN DOCUMENT FORM (CDM-PDD)
Version 03 - in effect as of: 28 July 2006

CONTENTS

SECTION A. General description of project activity

A.1. Title of the project activity:

El General Hydroelectric Project
Version 09.3
08/08/2013

A.2. Description of the project activity:

The El General Hydroelectric Project (hereinafter EGHP) consists of the construction, installation and operation of an hydroelectric power plant consisting of two vertical shaft turbines with a combined capacity of 40 MW, with an expected average annual net generation of approximately 198,380 MWh[1].

The electricity will be sold to the ICE (Instituto Costarricense de Electricidad), the government owned state enterprise responsible for the generation, transmission and distribution of electricity in Costa Rica.

Through the implementation of this project, the EGHP generates renewable electricity and is able to sell electricity to the Costa Rican grid, avoiding the dispatch of energy produced by fossil-fuelled thermal plants to that grid. The initiative avoids CO_2 emissions and contributes to the regional and national sustainable development. The project coincides with Costa Rica's long term development and energy strategy to provide electric energy from small-scale, renewable sources (wind, biomass, hydro, geothermic)[2].

It is a BOT (Build-Operate-Transfer) type project. Hidroenergía Del General, Sociedad de Responsabilidad Limitada, the developer of the project, received a concession from ICE to design, construct, and operate the EGHP for 17 years. After that, the ownership of the EGHP will be transferred back to the ICE.

The project generated 500 jobs during the construction phase and generates 22 local jobs during the operation phase.

EGHP´s social contribution was established with the creation of a Fund (called "Fondo Ecológico Social Educativo") that will be distributed directly to the communities near to the project with the objective to develop social, environmental and educational projects that can improve the quality of life of its population. This fund will be reverted during the 17 years of project operation. Moreover, the hydroelectric plant will be opened for educational visits.

The baseline scenario is the same as the scenario existing prior to the start of implementation of the project activity, which is the use of existing power plants connected to the Costa Rican SIN.

[1] EIA (Environmental Impact Assessment).
[2] ICE. "Plan de expansion de la generacion eléctrica 2002-2016". Aug, 2001. San José, Costa Rica.

A.3. Project participants:

Name of Party involved (*) ((host) indicates a host Party)	Private and/or public entity(ies) project participants (*) (as applicable)	Kindly indicate if the Party involved wishes to be considered as project participant (Yes/No)
Costa Rica (*)	Hidroenergia Del General S.R.L. (prívate entity)	No

(*) In accordance with the CDM modalities and procedures, at the time of making the CDM-PDD public at the stage of validation, a Party involved may or may not have provided its approval. At the time of requesting registration, the approval by the Party(ies) involved is required.

A.4. Technical description of the project activity:

A.4.1. Location of the project activity:

A.4.1.1. Host Party(ies):

Costa Rica.

A.4.1.2. Region/State/Province etc.:

Heredia and Limón.

A.4.1.3. City/Town/Community etc.:

Various: Sarapiquí (power plant); Heredia (water intake); Pococí (transmission line).

A.4.1.4. Details of physical location, including information allowing the unique identification of this project activity (maximum one page):

The project is located 50 km from San José and 102 km from Limón Harbor in the Atlantic Cost. It is on the left bank of the General River, downstream of the Braulio Carrillo National Park, which protects the water basin of the river.

Geographical coordinates: (10º12’49”; -83º54’56”).

Figure 1. Location map

A.4.2. Category(ies) of project activity:

Energy industries (renewable - / non-renewable sources), sectoral scope 1.

A.4.3. Technology to be employed by the project activity:

The project has excellent hydrology and a simple design with no tunnels. The project consists of a compact diversion dam 60 meters long and 6 meters height. The dam will divert a design flow of 18.5m^3/s from the *Río General* to the intake structure.

After that, the water flows in an open-canal of 930m to the ridge adjacent to Río General. From the canal, the water will flow through a concrete pipe with a diameter of 3.8 meters and a length of 3,400 m extending to a day reservoir, excavated at the end of the ridge. The purpose of this day reservoir is to manage daily output to match ICE's load profile. The capacity of the reservoir is 194,903 m^3. Then, the water flows through a 2,400 meter penstock (steel pipe) with a diameter of 3.25 m to the powerhouse.

Table 1. Technical data of the turbines

Manufacturer	Type	Capacity	Maximum Consumption	Maximum water head	Velocity
General Electric (Norway) AG	Francis	2 x 20.7 MW	9.25 m^3/s	247.6 m	720 rpm

Table 2. Technical data of the generators

Manufacturer	Type	Capacity	Capacity factor	Tension / Frequency	Nominal current	Velocity
General Electric-INEPAR (Brazil)	ATI Synchronico	2 x 23,530 kVA = 2 x 20 MW	85%	13,800 V / 60 Hz	984 A	720 rpm

Figure 2. The powerhouse

The water used to generate electricity will be returned to *Río General*, with no change in the quality or quantity of water.

In the event of seismic activity, preventive steps have been taken to provide adequate safety from slope sliding, including geotechnical design, retaining wall and gabions where necessary, construction of a drainage system and rapid re-vegetation with fast – growing species to avoid erosion and slop instability. Safety factors have been designed into the structures such as the reservoir to assure integrity during seismic activity.

The powerhouse is located above the 500 year flood level, the reservoir is provided with cut-off walls to improve anchoring to the ground, and the sluice structure is designed to bear the estimated hydraulic load to operate the plant in the event of flooding.

The maximum water head of the project is 247.6 m. The transmission line of 230 kV has a length of 21.5 km and connects the project activity to the Leesville substation in Roxanna. Hidroenergía Del General will construct and maintain all interconnection facilities on the plant's side of the point of interconnection.

O&M Eléctrica Matamoros S.A is responsible for operating the project.

The baseline scenario is the same as the scenario existing prior to the start of implementation of the project activity, which is the use of existing power plants connected to the Costa Rican Interconnected System.

A.4.4. Estimated amount of emission reductions over the chosen crediting period:

Years*	Annual estimation of emission reductions in tonnes of CO_2e
2011	27,500
2012	66,001
2013	66,001
2014	66,001
2015	66,001
2016	66,001
2017	66,001
2018	38,500
Total estimated reductions (tonnes of CO_2e)	462,006
Total number of crediting years	**7**
Annual average over the crediting period of estimated reductions (tonnes of CO_2e)	**66,001**

*From 1st August 2011 to 31st July 2018

A.4.5. Public funding of the project activity:

The project activity does not involve any public funding from Annex-1 countries.

SECTION B. Application of a baseline and monitoring methodology

B.1. Title and reference of the approved baseline and monitoring methodology applied to the project activity:

- ACM0002 Version 12.1 "Consolidated baseline methodology for grid-connected electricity generation from renewable sources";
- Version 05.2 of the "Tool for the demonstration and assessment of additionality";
- Version 02 of the "Tool to calculate the emission factor for an electricity system".

B.2. Justification of the choice of the methodology and why it is applicable to the project activity:

The EGHP is a grid-connected renewable power generation project activity that installs a new power plant at a site where no renewable power plant was operated prior to the implementation of the project activity.

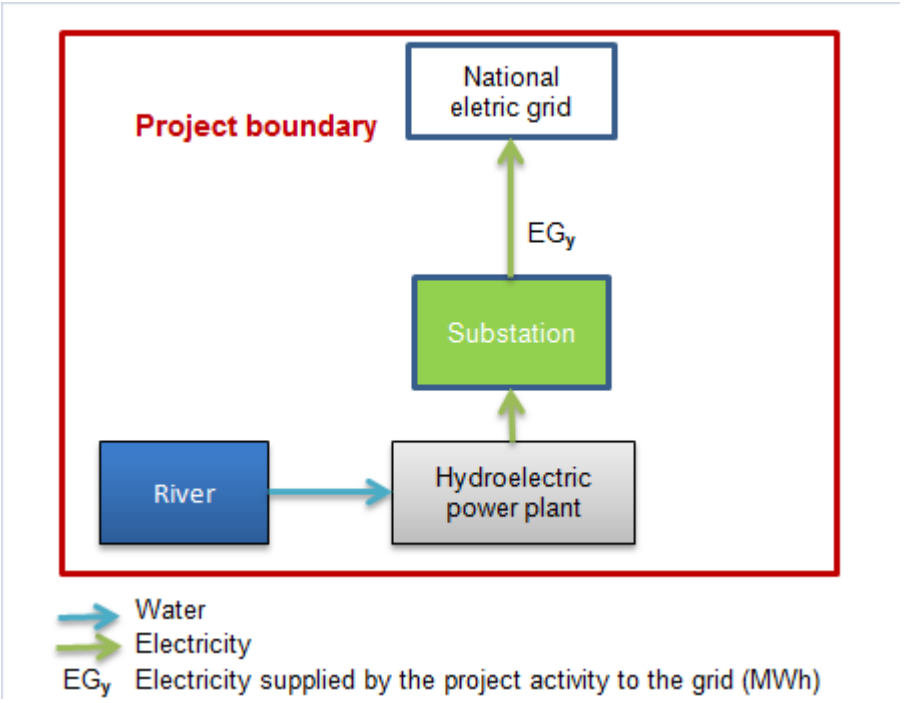
The approved baseline methodology ACM0002 is applicable to the proposed project activities, because:

- The EGHP is the installation of a hydro power plant (run-of-the-river and reservoir); [3]
- The EGHP results in new reservoirs and the power density of the power plant, is greater than 4 W/m^2. [4]

B.3. Description of the sources and gases included in the project boundary:

	Source	Gas	Included?	Justification / Explanation
Baseline	CO_2 emissions from electricity generation in fossil fuel fired power plants that is displaced due to the project activity.	CO_2	Yes	Main emission source.
		CH_4	No	Minor emission source.
		N_2O	No	Minor emission source.
Project Activity	For hydro power plants, emissions of CH_4 from the reservoir.	CO_2	No	Minor emission source.
		CH_4	No	The power density of the power plant is greater than 10 W/m^2. Then there are no project emissions.
		N_2O	No	Minor emission source.

Figure 3. Project boundary diagram



[3] EIA (Environmental Impact Assessment).
[4] Project design nº AE302 and turbo-generators plate data.

The hydroelectric project plant indicated in the flow diagram consists of the two turbines with a combined total capacity of 40 MW and two generators of 13,800 V/60 Hz.

B.4. Description of how the baseline scenario is identified and description of the identified baseline scenario:

The project activity is the installation of a new grid-connected renewable power plant/unit. Therefore, the baseline scenario is the following:

Electricity delivered to the grid by the project would have otherwise been generated by the operation of grid-connected power plants and by the addition of new generation sources, as reflected in the combined margin (CM) calculations described in the "Tool to calculate the emission factor for an electricity system" version 02.

B.5. Description of how the anthropogenic emissions of GHG by sources are reduced below those that would have occurred in the absence of the registered CDM project activity (assessment and demonstration of additionality):

The additionality was determined using the "Tool for the demonstration and assessment of additionality" Version 05.2.

As the starting date of the project activity is before the date of validation, an implementation timeline of the proposed CDM project activity is shown in Table 3.

Table 3. Implementation timeline of the EGHP

Date	Comment	Milestones
10/06/1999	-	ICE started the Public Bid No. 6670-E type BOT, called "Precalificación 15": Prequalification of companies for power plants of maximum 50 MW, published in the official newspaper: Diario Oficial La Gaceta No. 112. Developers, operators, equipments providers and companies in charge of the installation of the electrical/mechanical equipments were invited to participate in the Public Bid.
30/01/2000	-	Oxbow Power Corporation, a US based energy project development corporation, with expertise in the development, investments, construction and operation of small to medium size hydroelectric power plants, submitted a proposal to ICE in order to participate in the Public Bid 6670-E.
01/06/2000	-	The Directive Council of ICE announced the selection of Oxbow to develop the EGHP.
16/06/2000	CDM evidence	Draft of the proposed Rio General Emissions Purchase Agreement between Hidroenergía Del General and Prototype Carbon Fund (PCF).
21/11/2000	-	Hidroenergía Del General sent the Environmental Impact Assessment to SETENA (Secretaria Técnica Nacional Ambiental).
12/03/2001	CDM evidence	E-mail from Oxbow detailing the cash flow analysis with and without carbon credits (initial consideration of the CERs revenue in the cash flow analysis).

30/03/2001	CDM evidence	The Project Concept Note (PCN) was prepared by OCIC on behalf of the project developer for submission to PCF.
19/04/2001	CDM evidence	The Costa Rican Joint Implementation Office (OCIC, Oficina Costarricense de Implementación Conjunta), currently the Designated National Authority for the CDM, sent the Project Idea Note (PIN) of Hidroenergía Del General's CDM Project to PCF for consideration under the Costa Rica Umbrella Carbon Project in conjunction with the PCF at the World Bank, in order to receive the potential generation of carbon offsets from the project.
05/09/2001	-	Hidroenergía Del General SRL requested the water use concession.
12/12/2001	-	SETENA approved the Environmental Impact Assessment of the project.
19/08/2002	CDM evidence	Letter to Mr. John Stauffer at Oxbow Power Corporation from Mr. Juan Ramirez, President Grupo Saret, referencing the on-going negotiations related to the agreement to acquire the ownership rights that Oxbow Power Corporation had over the El General Hydro Project. In the document, it is acknowledged and clearly referenced the financial proforma being used by the parts in order to assess the merits of the project. That referenced proforma is named "Rev.08-b" (p.15). This document is a clear evidence of decisive consideration of CER revenues at the time of investment decision making. Such proforma incorporates the CER revenues in the project financial analysis, therefore indicating the decisive character of the consideration of CER revenues in the investment analysis.
10/12/2002	CDM evidence	Grupo Saret sends a letter to Hidroeléctrica Platanar S.A. enclosing a document entitled "Proyecto Hidroeléctrico El General", with the purpose of further consideration by the Board of Directors at Hidroeléctrica Platanar to a decision to invest in the acquisition of the project. This document clearly indicates decisive consideration of CER revenues at the time of investment decision making (see on p.9: the EGHP may obtain additional revenues for the environmental services by renewable electricity generation). By such date it is clear that the revenues of the CDM was considered decisive by the different parties involved in the transaction.
30/01/2003	-	Hidroenergía Del General received the water use concession, granted by the Ministry of Environment and Energy (MINAE) of Costa Rica.
20/03/2003	CDM evidence	Negotiation meeting minute between Hidroeléctrica Platanar, S.A.[5] , Grupo Corporativo Saret, S.A. and GCS. One of the topics stated in this minute is about the meeting with the World Bank about the clean electricity generation and the CERs benefits. The World Bank showed interest in sending a letter of intention related to the EGHP.
05/05/2003	-	ICE and Hidroenergía Del General SRL signed the Power Purchase Agreement (PPA).
22/05/2003	CDM evidence	Letter of intent of potential purchase of emission reductions of EGHP by International Bank for Reconstruction and Development (IBRD), acting as the trustee of the PCF, stating the nature of a Potential Purchase of Emissions Reductions and a clause of exclusivity signed by the parties. The letter of intent provides details on the expected value of the emission reduction under negotiation.
09/12/2003	CDM	Hidroenergía Del General S.R.L. Shareholders Extraordinary Assembly

[5] In 2004 the shareholders of Hidroenergia Del General were Hidroeléctrica Platanar, S.A. (70%), Oxbow Power Corporation (20%) and Saret Sistemas Energeticos, S.A. (10%). In 2006 the shareholders changed to Platanar (87.5%) and Saret (12.5%).

	evidence	Meeting #10. The World Bank indicates that the project shall deviate the transmission line route in order to avoid social displacement in order to continue the CDM process with the World Bank.
26/01/2004	**Start of project activity**	Saret de Costa Rica S.A. signed an Engineering, Procurement and Construction (EPC) Contract with Hidroenergía Del General SRL.
20/02/2004	CDM evidence	Hidroenergia Del General SRL sent a letter to the World Bank (Carbon Finance Unit) informing them that they decided to authorize a modification to the path for the transmission line that interconnects the project´s power house with ICE´s Leesville substation. They were committed to solving this situation before the date of signing an agreement with the World Bank regarding the purchase of emission reductions. This document shows the importance of the CDM for the implementation of the project.
07/05/2004	CDM evidence	Hidroenergía Del General SRL finalized a financing agreement with RBTT Merchant Bank Limited as the initial lender and administrative agent. This agreement defines the terms and conditions of the financings and that all forms of revenues were to be received by the Lender and included in the calculation of Financial Covenants, Dividend Payments and cash Flow available for Debt Service. The revenues derived from the sale of carbon bonds were highlighted in the financial projections analyzed by RBTT Merchant Bank Limited and all participating banks. Ratio covenants included in the Credit Agreement would be breached if revenues derived from the sale of carbon bonds were not included in the overall financial position. This document clearly indicates how CER revenues were decisive for project financing.
07/10/2004	CDM evidence	Amendment to the Letter of Intent of potential purchase of emission reductions for Hidroenergia Del General SRL: El General Hydroelectric Power Plant, dated on 19/04/2004, signed by duly representatives from Hidroenergía Del General SRL, and the carbon Finance Unit at the World Bank. The amendment to the letter of intent maintains the expectative on the price being negotiated for the emission reduction. The letter is valid until 19/01/2005 (“Exclusivity Period”).
01/03/2005	CDM evidence	PCF decided to stop extending the Letter of Intent to purchase emissions reductions from the EGHP. PCF justifies their decision due to constraint on obtaining hourly dispatch data of the Costa Rican electric grid. They had to calculate the baseline emission factor using the average operating margin. The calculations yielded to low emission reductions and the EGHP was not a viable candidate for the PCF or for any of their carbon funds. Since that time, Hidroenergía Del General concentrated its efforts to start the operation of the project and started looking for other options to develop the PDD and certify the EGHP under the CDM.
24/05/2005	CDM evidence	Hidroeléctrica Platanar S.A. Board meeting 10-2005: it is proposed to request from Sr. Adrian Bellavita (Grupo Saret), information about the negotiation of the carbon credits.
25/08/2005	CDM evidence	Hidroeléctrica Platanar S.A. Board meeting 15-2005: Under Accord No.1 Item B: it is indicated that a field trip was conducted with a representative from FUNDECOR, FUNDECOR being a local organization involved in carbon project development; in order to discuss the CDM status of the project and the undergoing efforts in order to register the project under the CDM.The project developer maintains the CERs revenue as a benefit for

		the project. This document clearly indicates continuing consideration of CER revenues.
07/09/2005	CDM evidence	Letter from Mr. William Alpizar, Coordinator of the Technical Unit at *Oficina Costarricense de Implementación Conjunta* (OCIC), following telephone conversations between representatives of EGHP and the Director of OCIC; requesting a visit to the project site in order to provide follow-up to the status and efforts to develop the carbon CDM components of the project.
13/09/2005	CDM evidence	Hidroenergía Del General SRL conducts a "Reunión de Asamblea Extraordinaria de Cuotistas", and receives a visit from representatives of the Costa Rican DNA in order to discuss relevant aspects of the development of the project and the carbon aspects of it. Minutes of the "Reunión de Junta de Cuotistas No 29" of Hidroenergía Del General SRL, reporting on the visit that was arranged on 07/09/2005; in which the Director and the Technical Unit Coordinator at the Costa Rican DNA visited the project site in order to follow-up on issues related to registration of the project under the CDM.
07/10/2005	CDM evidence	E-mail exchanged with World Bank consultant that had visited the project recently. Although the message does not indicate clearly the purpose of the site visit, it does indicate clearly that the project developer remained interested in pursuing CDM registration.
28/01/2006	-	Start of the commissioning period.
09/03/2006	CDM evidence	Hidroeléctrica Platanar S.A. Board meeting 03-2006: a possible scenario of electricity and CERs revenue´s ownership is presented.
24/04/2006	-	Start of electricity dispatched to the grid.
23/05/2006	CDM evidence	Hidroeléctrica Platanar S.A. Board meeting 06-2006: the project developer maintains the CERs revenue as a benefit for the project.
06/02/2007	CDM evidence	E-mail with information about the contacts made to find alternatives to continue the actions to obtain the CERs revenue: 23/01/2007 - talks with Mr. Franz Tattenbach (Ex-member of UNFCCC Executive Board), 30/01/2007 - Meeting with Mr. Adrián Bellavita (Grupo Saret) and 01/02/2007 – Meeting with Mr. Oscar Coto. This document clearly indicates continuing consideration of CER revenues.
26/04/2007	CDM evidence	Contract between a local consultant and Hidroenergía del General SRL. As part of management decisions, in order to continue with CDM project development, a local Costa Rican consultant is contracted to conduct an assessment of additionality for the project considering the new UNFCCC procedures. This document clearly indicates continuing consideration of CER revenues.
06/11/2007	CDM evidence	Econergy enters into agreement with Hidroenergia del General SRL in order to finalize and retake the CDM project cycle. This document clearly indicates continuing consideration of CER revenues.
16/07/2008	CDM evidence	RBTT Merchant Bank Limited, the company which has a loan agreement with Hidroenergia del General, wants to know the status of the carbon credit negotiations. This document clearly indicates the continuing interest of RBTT in the CERs revenue.
04/12/2008	CDM evidence	Hidroenergia del General SRL sent a letter to RBTT Merchant Bank Limited to inform about the status of CDM project and an analysis of the difference of the projected and actual income statements for the years 2006,

		2007 and 2008.

Hidroenergía del General SRL is a registered society of limited responsibility under the Costa Rican law. Its existence was a requirement under the bidding process that was established by ICE in Public Bid 6670-E. Several ownership structures have taken place through the process of developing the project. At the beginning, Oxbow Power Corporation was the principal investor in the project, but by 2002 Oxbow Power Corporation was interested in selling its ownership of the project, having invited in turn Grupo Saret to acquire the project. By the end of 2002, Grupo Saret invited Hidroeléctrica Platanar S.A. to participate in the acquisition of the project, a process that concludes with the current ownership structure of Hidroenergía del General SRL by Grupo Saret and Hidroeléctrica Platanar S.A.

Table 3 shows and highlights the evidence to demonstrate that the CDM was seriously considered in the decision to implement the project activity and that continuing and real actions were taken to secure CDM status for the project in parallel with its implementation.

STEP 1: Identification of alternatives to the project activity consistent with current laws and regulations

Sub-step 1a: Define alternatives to the project activity
The alternative scenarios available to the project participants and that provide outputs or services with comparable quality, properties and application areas as the proposed CDM project activity are:

a) The proposed project activity undertaken without being registered as a CDM project activity;
b) Continuation, of the current situation (no project activity or other alternatives undertaken).

Sub-step 1b: Consistency with mandatory applicable laws and regulations
The alternative scenarios are in compliance with all mandatory applicable legal and regulatory requirements of Costa Rica.

Step 2. Investment analysis

Sub-step 2a: Determine appropriate analysis method

As the alternatives identified in Step 1 generate financial or economic benefits other than CDM related income, the benchmark analysis (Option III) was used.

Sub-step 2b: Option III. Apply benchmark analysis

For the purpose of this investment analysis, the IRR was considered the most suitable indicator for comparing all the scenarios under analysis. The appropriate benchmark comparison as presented below was defined according to the "Tool for the demonstration and assessment of additionality" (Additionality Tool) and in line with the "Guidelines on the Assessment of Investment Analysis" (Guidance on Investment Analysis) Version 05.

This version allows project participants to select a relevant benchmark value, IRR, for their proposed CDM project activity depending on the country and sector.

Taking note of paragraph 7 of the said guidance "In situations where an investment analysis is carried out in nominal terms, Project Participants can convert the real term values provided in table below to nominal values by adding the inflation rate. The inflation rate must be obtained from the inflation forecast of the

central bank of the host country for the duration of the crediting period. If this information is not available, the target inflation rate of the central bank shall be used. If this information is also not available, then the average forecasted inflation rate for the host country published by the IMF (International Monetary Fund World Economic Outlook) or the World Bank for the next five years after the start of the project activity shall be used".

The benchmark parameter used for this comparison analysis was calculated as follows:

Table 4. Benchmark calculation

Benchmark EGHP	%
Return benchmark for Costa Rica (Real Terms)[6]	12
Average inflation[7]	4.7%
Nominal rate of return	17.2%

The formula employed to calculate the nominal rate of return is:

$$Nominal\ rate = (1 + Real\ Rate) \times (1 + inflation) - 1$$

Where:

Real rate: real rate of return benchmark provided by HDG (12%).
Inflation: annual inflation measured in USD, but calculated based on local inflation (CRC) forecast provided by IMF and forex (CRC/USD) devaluation forecast provide by EIU

Considering all these premises, the after tax return on equity in real terms for this project activity is 12% but considering this value in nominal terms with an inflation rate of +4.7%, the return on equity reaches the value of 17.2%.

Sub-step 2c: Calculation and comparison of financial indicators

The financial indicator was based on the equity IRR for the EGHP lifetime.

The investment analysis with all the relevant assumptions is presented in table 4 and 5.

[6] "Guidelines on the Assessment of Investment Analysis" (Guidance on Investment Analysis) Version 05

[7] "HDG-Report-rate Return-Mar2012v4.pdf", page 4 (KPMG report based on IMF historic values)

Table 4. EGHP`s Cash Flow - Part I

All values in US Dollars

	-2	-1	0	1	2	3	4	5	6	7
El General Hydroelectric Power Plant	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Capacity Payment				4,088	4,088	4,088	4,088	4,088	4,088	4,088
Energy Payment				9,637	9,688	9,738	9,789	9,841	9,892	9,944
Total Revenues				**13,725**	**13,775**	**13,826**	**13,877**	**13,928**	**13,980**	**14,032**
Total Operating Expenses (O&M)				**1,104**	**1,145**	**1,147**	**1,148**	**1,650**	**1,153**	**1,155**
Operating Profit				**12,621**	**12,630**	**12,679**	**12,729**	**12,278**	**12,827**	**12,876**
Transfer Cost to ICE										
Depreciation & Amortization				5,191	5,191	5,191	5,191	5,191	3,961	3,961
Total Other Expenses				**5,191**	**5,191**	**5,191**	**5,191**	**5,191**	**3,961**	**3,961**
Earnings Before Interest & Taxes				**7,430**	**7,439**	**7,488**	**7,538**	**7,087**	**8,867**	**8,916**
Taxes	0	0	0	0	0	(339)	(679)	(825)	(1,499)	(1,769)
Depreciation & Amortization	0	0	0	5,191	5,191	5,191	5,191	5,191	3,961	3,961
Changes in working capital	0	0	(125)	0	0	0	0	0	0	0
Total cash flow from operations	0	0	(125)	12,621	12,630	12,340	12,050	11,453	11,328	11,108
EPC Contract	(8,294)	(24,057)	(20,461)							
Land and Rights of Way	(5,851)	0	0							
Development Costs	(8,596)	(485)	(2,640)							
Total Cash from Investing Activities (CAPE	(22,741)	(24,542)	(23,101)	0	0	0	0	0	0	0
Senior Loan	1,361	25,607	26,074							
Equity contribution (30%)	22,732	0	0							
Financing costs	(1,353)	(258)	(81)							
Interest during construction	0	(806)	(2,767)							
Senior Loan (debt service)	0	0	0	(6,284)	(8,639)	(8,274)	(7,908)	(7,543)	(7,177)	(6,812)
Senior Loan (debt service reserve)	0	0	0	(4,320)	0	183	183	183	183	183
Total Cash from Financing Activities	22,741	24,542	23,226	(10,603)	(8,639)	(8,091)	(7,725)	(7,360)	(6,994)	(6,629)
Begining cash balance	0	0	0	0	500	500	500	500	500	500
Ending cash balance	0	0	0	500	500	500	500	500	500	500
Dividend payment	0	0	0	1,518	3,991	4,250	4,325	4,093	4,334	4,479
Equity Cash flow	(22,732)	0	0	1,518	3,991	4,250	4,325	4,093	4,334	4,479
IRR=	**14.86%**									

Table 5. EGHP`s Cash Flow - Part II

All values in US Dollars

	8	9	10	11	12	13	14	15	16	17	18
El General Hydroelectric Power Plant	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Capacity Payment	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	4,088	
Energy Payment	9,996	10,049	10,101	10,154	10,207	10,261	10,315	10,369	10,423	10,478	
Total Revenues	**14,084**	**14,136**	**14,189**	**14,242**	**14,295**	**14,349**	**14,402**	**14,456**	**14,511**	**14,565**	**0**
Total Operating Expenses (O&M)	**1,158**	**1,162**	**1,665**	**1,169**	**1,173**	**1,177**	**1,182**	**1,687**	**1,192**	**1,197**	**0**
Operating Profit	**12,926**	**12,975**	**12,524**	**13,073**	**13,122**	**13,171**	**13,220**	**12,770**	**13,319**	**13,369**	**0**
Transfer Cost to ICE										750	
Depreciation & Amortization	3,961	3,961	3,961	3,434	3,434	3,434	3,434	3,434	3,434	3,434	0
Total Other Expenses	**3,961**	**3,961**	**3,961**	**3,434**	**3,434**	**3,434**	**3,434**	**3,434**	**3,434**	**4,184**	**0**
Earnings Before Interest & Taxes	**8,965**	**9,014**	**8,563**	**9,639**	**9,688**	**9,737**	**9,786**	**9,336**	**9,885**	**9,184**	**0**
Taxes	(2,038)	(2,306)	(2,424)	(2,850)	(2,920)	(2,935)	(2,949)	(2,814)	(2,965)	(2,755)	0
Depreciation & Amortization	3,961	3,961	3,961	3,434	3,434	3,434	3,434	3,434	3,434	3,434	0
Changes in working capital	0	0	0	0	0	0	0	0	0	0	125
Total cash flow from operations	10,888	10,668	10,099	10,223	10,202	10,237	10,271	9,956	10,354	9,863	125
EPC Contract											
Land and Rights of Way											
Development Costs											
Total Cash from Investing Activities (CAPE	0	0	0	0	0	0	0	0	0	0	0
Senior Loan											
Equity contribution (30%)											
Financing costs											
Interest during construction											
Senior Loan (debt service)	(6,446)	(6,081)	(5,715)	(2,721)	0	0	0	0	0	0	0
Senior Loan (debt service reserve)	183	183	183	1,497	1,360	0	0	(0)	0	0	0
Total Cash from Financing Activities	(6,264)	(5,898)	(5,533)	(1,223)	1,360	0	0	(0)	0	0	0
Begining cash balance	500	500	500	500	500	500	500	500	500	500	500
Ending cash balance	500	500	500	500	500	500	500	500	500	500	0
Dividend payment	4,624	4,770	4,567	9,000	11,562	10,237	10,271	9,956	10,354	9,863	625
Equity Cash flow	4,624	4,770	4,567	9,000	11,562	10,237	10,271	9,956	10,354	9,863	625
IRR=											

The equity IRR, excluding CER revenue, was calculated at 14.86% p.a., which is lower than the benchmark of 17.2% p.a.

Sub-step 2d: Sensitivity analysis

The parameters used in the sensitivity analysis were selected to determine the likelihood of the occurrence of a scenario other than the scenario presented. The parameters selected in Table 6 have a material impact in the investment analysis.

Table 6. IRR for different variations

SCENARIO	IRR
Base case	14.86%
+10% REVENUE	17.88%
-10% REVENUE	11.59%
+10% Energy Revenue only	16.41%
-10% Energy Revenue only	13.13%
+10% CAPEX	12.15%
-10% CAPEX	18.57%
+10% CAPEX without EPC contract	14.04%
-10% CAPEX without EPC contract	15.76%
+10% O&M	14.57%
-10% O&M	15.14%

An increment of 10% in the capacity-based price is not possible, since it is fixed in the PPA signed.. If the capacity-based price is maintained constant and the remainder energy-based revenue is increased by 10% (either by increasing the energy-based price or the energy volumes), the IRR does not pass the benchmark.

The El General PPA defines how the electricity tariff is calculated (paragraph 7.1.2 a):

- The electricity generated with a load factor up to 0.6 will have the price of 5 USD cents (0.05 USD/kWh);
- The electricity generated with a load factor from 0.61 to 0.66 will have the price of 20% of the electricity tariff (i.e. 0.05*20% = 0.01 USD/kWh);
- The electricity generated with a load factor from 0.67 to 0.72 will have the price of 15% of the electricity tariff (i.e. 0.05*15% = 0.008 USD/kWh);
- The electricity generated with a load factor from 0.73 to 1 will have the price of 10% of the electricity tariff (i.e. 0.05*10% = 0.005 USD/kWh);

According to the PPA, the relation between electricity generation and revenues is non-linear; therefore a 10% increase in the electricity generation would not increase the revenues in 10%. In fact, in order to increase the revenue in 10%, it would be necessary to increase energy volume by 22% throughout the project lifetime, which would result in an average load factor of 70%. Considering that the project was modeled on a 33 years hydrology database (provided to the DOE team), a load factor of 70% is extremely unlikely.

A reduction of 10% in the CAPEX is very unlikely, since the EPC contract represents 70% of the project CAPEX and its price was already agreed on as of December 2002 according to the letter sent by Grupo Saret to Hidroeléctrica Platanar S.A. If the EPC price is maintained constant and one reduces the remainder of the CAPEX in 10%, the IRR does not reach the benchmark.

All other variations do not lead to IRRs higher than the benchmark.

Therefore, the sensitivity analysis confirms that if the project is not registered as a CDM project, IRR is below the benchmark, proving that it is not financially attractive to the investor.

Step 3: Barrier analysis

Although the Project Participant believes that there were barriers to this project, it decided not to present them due to the fact that the Investment Analysis above is sufficient to prove the additionality of EGHP.

STEP 4. Common practice analysis

Sub-step 4a. Analyze other activities similar to the proposed project activity:

According to the "*Tool for the Demonstration and Assessment of Additionality*", Project Proponents shall "*provide an analysis of any other activities that are operational and that are similar to the proposed project activity. Projects are considered similar if they are in the same country/region and/or rely on a broadly similar technology, are of a similar scale, and take place in a comparable environment with respect to regulatory framework, investment climate, access to technology, access to financing, etc*." Based on this definition, the criteria and the characteristics of the proposed project activity to identify similar operational activities are presented in the table below.

Table B 1: Characteristics of the proposed project activity

Criteria		Characteristics of similar Hydroelectric Power Plants (HPPs)
1	**Type of project and Location**	HPPs developed in Costa Rica
2	**Type of developer**	HPPs developed by private entities that are not cooperatives
3	**Scale**	HPPs with an installed capacity above 20MW
4	**CDM Project Activity**	HPPs that have been published for Global Stakeholder Process

Criteria 1. HPPs developed in Costa Rica
Hydro power plants differ significantly from other generation project types, therefore only hydro power plants were considered in this Common Practice Analysis. Also, the regulatory environment for power project varies considerably from country to country, therefore only projects from Costa Rica were considered.

Criteria 2. HPPs developed by private entities that are not cooperatives
Projects developed by state-owned utilities were excluded as the decision making processes in state-owned utilities differ significantly from those of private developers. Projects developed by cooperatives were also excluded for the same reason, since cooperatives can be considered self-generators as the energy from their projects is mainly dedicated to fulfill the demand of the members of the cooperative.
In addition, the Costa Rican law no. 7092 article 3, states that cooperatives do not to pay income taxes. Another reason to justify that projects developed by cooperatives have had economic/financial benefits, that were/are not available for private companies such as EGHP.

Criteria 3. HPPs with an installed capacity between 20MW and 50 MW and in the same investment environment
Law 7200 (28/09/1990) and Law 7508 (09/05/1995) clearly differentiate generation projects of a capacity of 20 MW of less from larger generation projects. Projects with installed capacity between 20 MW and 50 MW could be developed only under law 7508. This law defines that:

- The electricity will be bought only through a tender process (article 21);
- Projects larger than 20 MW will be transferred to ICE after a period, i.e. BOT (Build, Operate, Transfer) scheme;
- BOT projects could have, altogether, 15% of the SIN power generation;

As in law 7200 chapter I there is no requirement to transfer the assets after a determined period to ICE, all projects with capacity under 20MW are developed under this law. This statement could be evidenced in the expansion plan (Table 11.1 page 57), as in 2007 there were only 3 projects developed under the BOT scheme, listed below:

- Miravalles III, a geothermal power plant, in operation since 2000 with installed capacity of 26MW;
- El General, the project activity;
- La Joya, a hydro power plant, in operation since 2006 has 50 MW installed capacity. This is also a CDM project activity[8].

In addition, due to the lack of funds to invest in the power generation sector, Costa Rica changed its laws to allow private participation and investment in the sector, under the IPP or the BOT framework. The country has commenced this change in its strategy with the issuance of Law 7200 (28/09/1990) and Law 7508 (09/05/1995). Only after law 7508, projects with capacity of over 20MW but lower than 50MW could be developed by private investors under BOT scheme. Prior to this, the private investors were limited to 20MW. This regulatory change allowed the BOTs (i.e. private sector) to sell electricity to ICE (the only buyer in Costa Rica), thus being considered a milestone in the sector.

Project developers, in order to have a BOT project, must participate in an ICE tender. In all tenders so far, it is clear that the tenders are only applicable to projects with installed capacity between 20MW and 50MW[9]. This is another crucial difference from projects below 20 MW, as these projects should only present a project proposal to ICE, according to law 7200.

Moreover, some macro-economic parameters might have changed. The project participants considered for this analysis that all power plants in operation after 1995 are in the same investment environment, due to the abovementioned regulatory change.

Criteria 4. HPPs that have been published for Global Stakeholder Process (GSP)
According to the "*Tool for the demonstration and assessment of additionality*" – version 05.2, page 10, Sub-step 4a: "Other CDM project activities (registered project activities and project activities which have been published on the UNFCCC website for global stakeholder consultation as part of the validation process) are not to be included in common practice analysis". There are 2 other hydro projects from Costa Rica published for GSP, both of which have been registered: Cote (6.3 MW plant submitted by state utility CNFL)[10] and La Joya (50 MW plant submitted by private developer Union Fenosa).[11]

[8] http://cdm.unfccc.int/Projects/DB/AENOR1154424472.86/view

[9] In the specific case of the tender for El General, the applicable projects had to have an installed capacity between 30 MW and 50 MW. The El General tender was submitted to the audit team.

[10] http://cdm.unfccc.int/Projects/DB/DNV-CUK1137675448.01/view

[11] http://cdm.unfccc.int/Projects/DB/AENOR1154424472.86/view

The analysis of similar activities comprises all operational hydropower plants connected to the national transmission grid (defined as the project boundary). These plants are presented in the table below.[12]

Hydro Power Plant	Exclusion according to criteria: 1	2	3	4	COD	Power Capacity (MW)	Owner	Type of developer	Published for GSP?
Barro Morado		X	X		1916	0.87	JASEC	State utility	No
Cacao		X	X		1928	0.67	ICE	State utility	No
Avance		X	X		1938	0.24	ICE	State utility	No
Puerto Escondido		X	X		1940	0.18	ICE	State utility	No
Lotes		X	X		1956	0.375	ICE	State utility	No
Garita		X	X		1958	40	ICE	State utility	No
Rio Macho		X	X		1963	134	ICE	State utility	No
Birrís 3		X	X		1964	3.39	JASEC	State utility	No
Cachi		X	X		1967	103	ICE	State utility	No
Arenal		X	X		1979	157	ICE	State utility	No
Corobicí-Dengo		X	X		1982	174	ICE	State utility	No
Ventanas Garita		X	X		1988	100	ICE	State utility	No
Birrís 1		X	X		1990	14.3	JASEC	State utility	No
Echandi		X	X		1990	5	ICE	State utility	No
Sandillal		X	X		1993	32	ICE	State utility	No
Toro I		X	X		1996	27	ICE	State utility	No
Toro II		X	X		1997	66	ICE	State utility	No
Chocosuela I		X	X		1999	8	COOPELESCA	Private/Cooperative	No
Angostura		X	X		2000	180	ICE	State utility	No
Peñas Blancas		X	X		2002	37	ICE	State utility	No
Chocosuela II		X	X		2003	15	COOPELESCA	Private/Cooperative	No
Chocosuela III		X	X		2003	5	COOPELESCA	Private/Cooperative	No
General				X	2006	40	Hidroenergía Del General S.R.L	Private	Yes
La Joya				X	2006	50	Union Fenosa	Private	Yes
Cariblanco		X	X		2007	84	ICE	State utility	No

[12] The main source of information for this table is the Costa Rica National Expansion Plan of 2010-2021 (*Plan de Expansión de la Generación Eléctrica 2010-2021*, page 63, available at http://www.grupoice.com). Some minor details were also obtained in the websites of each individual generator (http://www.grupoice.com/, http://www.esph-sa.com/, http://www.cnfl.go.cr/, http://www.coopelesca.co.cr/, http://www.jasec.co.cr/, and http://www.coopeguanacaste.com/). Last accessed on 09/09/2010.

Canalete		X	X		2007	18	Coopeguanacaste	Private/Cooperative	No
Private generation*			X		various	127	Various owners	Private	No
CNFL (various plants)		X	X		various	71	CNFL	State utility	No
ESPH (various plants)		X	X		various	19	ESPH	State utility	No

*22 HPPs from 50 kW to 17 MW

As one can confirm from the table above, Costa Rica's electric power and distribution is mainly supplied by the state-owned utility, the Costa Rican Institute of Electricity (ICE), and its subsidiary, the National Power and Light Company (Compañia Nacional de Fuerza y Luz, CNFL).

According to the Costa Rica's National Energy Expansion Plan 2010-2019,[13] in 2008 the interconnected system of Costa Rica had an effective installed capacity of 2,313 MW, 66% of this is in hydroelectric power plants, 23% in thermal power plants, 7% in geothermal power sources and only 3% in wind power plants. From the total installed capacity, the stated controlled ICE operates 79.5%, the private power generators operate 13.8% and the distribution companies operate 6.7%.

There have been only 2 private hydro projects with installed capacity over 20 MW. During the Public Bid No. 6670-E, five projects were submitted to ICE: El General, Coton, Jabalina, Jimenez and La Joya. However, ICE decided to allocate only three blocks of power to 3 specific hydro projects: El General (40MW), La Joya (50MW) and Jimenez (50MW). The Jimenez project did not proceed due to problems in obtaining the required environmental permits. Only the El General and La Joya projects proceeded to development stages, both under the BOT scheme. The La Joya project was registered as a CDM project on 09/03/2007.

Based on the above, it seems reasonable to conclude that there is no other project similar to the project activity that hasn't been registered with the CDM.

[13] Available at http://www.grupoice.com/esp/ele/planinf/docum/plan_expansion_generacion_09.pdf . Last accessed on 09/09/2010.

Sub-step 4b. Discuss any similar options that are occurring:

Based on the analysis performed under Step 4a, no similar project activities could be observed in Costa Rica.

Conclusion Step 4

The proposed project activity is not common practice and is additional under Step 4.

B.6. Emission reductions:

B.6.1. Explanation of methodological choices:

Project emissions

$PE_y = PE_{FF,y} + PE_{GP,y} + PE_{HP,y}$ **(Equation 2)**

Where:
PE_y = Project emissions in year y (tCO2e/yr)
$PE_{FF,y}$ = Project emissions from fossil fuel consumption in year y (tCO2/yr)
$PE_{GP,y}$ = Project emissions from the operation of geothermal power plants due to the release of non-condensable gases in year y (tCO2e/yr)
$PE_{HP,y}$ = Project emissions from water reservoirs of hydro power plants in year y (tCO2e/yr)

As the project activity does not involve fossil fuel consumption and is not a geothermal power plant:
$PE_y = PE_{HP,y}$

As the power density (*PD*) of the hydro power plant is greater than 10 W/m^2: $PE_{HP,y} = 0$

The power density of the project activity is calculated as follows:

$$PD = \frac{Cap_{PJ} - Cap_{BL}}{A_{PJ} - A_{BL}} \quad \textbf{(Equation 3)}$$

Where:
PD = Power density of the project activity, in W/m^2;
Cap_{PJ} = Installed capacity of the hydro power plant after the implementation of the project activity (W).
Cap_{BL} = Installed capacity of the hydro power plant before the implementation of the project activity (W). For new hydro power plants, this value is zero;
A_{PJ} = Area of the reservoir measured in the surface of the water, after the implementation of the project activity, when the reservoir is full (m^2) [14];
A_{BL} = Area of the reservoir measured in the surface of the water, before the implementation of the project activity, when the reservoir is full (m^2). For new reservoirs, this value is zero.

[14] Project design nº AE302.

$$PD = \frac{40{,}000{,}000 - 0}{46{,}993 - 0} = 851$$

Baseline emissions

Baseline emissions include only CO_2 emissions from electricity generation in fossil fuel fired power plants that are displaced due to the project activity, calculated as follows:

$BE_{,y} = EG_{,PJ,y} \times EF_{grid,CM,y}$ **(Equation 4)**

Where:
BE_y = Baseline emissions in year *y* (tCO_2/yr);
$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year y (MWh/yr);
$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor for grid connected power generation in year *y* calculated using the "Tool to calculate the emission factor for an electricity system" version 02 (tCO_2/MWh).

Calculation of $EG_{PJ,y}$

(a) Greenfield renewable energy power plants

As the project activity is the installation of a new grid-connected renewable power plant/unit at a site where no renewable power plant was operated prior to the implementation of the project activity, then:

$EG_{PJ,y} = EG_{facility,y}$ **(Equation 5)**

Where:
$EG_{PJ,y}$ = Quantity of net electricity generation that is produced and fed into the grid as a result of the implementation of the CDM project activity in year y (MWh/yr)
$EG_{facility,y}$ = Quantity of net electricity generation supplied by the project plant/unit to the grid in year y (MWh/yr)

Leakage

No leakage emissions are considered. The main emissions potentially giving rise to leakage in the context of electric sector projects are emissions arising due to activities such as power plant construction and upstream emissions from fossil fuel use (e.g. extraction, processing, transport). These emissions sources are neglected.

Emission reductions

Emission reductions are calculated as follows:

$ER_y = BE_y - PE_y$ **(Equation 6)**

Where:
ER_y = Emission reductions in year *y* (t CO_2e/y).
BE_y = Baseline emissions in year *y* (t CO_2e/y).

PE_y = Project emissions in year *y* (t CO_2/y).

As no project emissions were identified for this project, $ER_y = BE_y$.

Then, $ER_y = EG_{facility,y} \times EF_{grid,CM,y}$ **(Equation 7)**

Emission factor

The baseline emission factor ($EF_{grid,CM,y}$) is calculated as a combined margin (CM), consisting of the combination of operating margin (OM) and build margin (BM) factors, following the procedures established in the "Tool to calculate the emission factor for an electricity system" version 02. Calculations for this combined margin were based on data from an official source and made publicly available.

Step 1. Identify the relevant electricity system
For the purpose of determining the electricity emission factor, a project electricity system is defined by the spatial extent of the power plants that are physically connected through transmission and distribution lines to the project activity.

In the case of the EGHP project, the connected grid is the Costa Rican Interconnected System (*SNI – Sistema Nacional Interconectado*) and all connected power plants (without significant transmission constraints) are included in the project boundary.

Step 2: Choose whether to include off-grid power plants in the project electricity system (optional)
Not applied as there is no off-grid power plant to be included in the project electricity system.

Step 3. Select a method to determine the operating margin (OM)
The method used to calculate the operating margin emission factor ($EF_{grid,OM,y}$) was the Simple Adjusted OM (b).

The data vintage used was the ex ante option. It was chosen ex ante because it is expected that the OM will not have a wide range of variation during the first crediting period. The emission factor is determined once at the validation stage, thus no monitoring and recalculation of the emissions factor during the crediting period is required. It was used a 3-year generation-weighted average, based on the most recent data available at the time of submission of the CDM-PDD for validation (2005, 2006 and 2007).

Step 4. Calculate the operating margin emission factor according to the selected method

(b) Simple adjusted OM

The simple adjusted OM emission factor ($EF_{grid,OM-adj,y}$) is a variation of the simple OM, where the power plants/units (including imports) are separated in low-cost/must-run power sources (k) and other power sources (m).

As under Option A of the simple OM, it is calculated based on the net electricity generation of each power unit and an emission factor for each power unit, as follows:

(Equation 8)

$$EF_{grid,OM-adj,y} = (1-\lambda_y)\frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} + \lambda_y \times \frac{\sum_k EG_{k,y} \times EF_{EL,k,y}}{\sum_k EG_{k,y}}$$

Where:

$EF_{grid,OM-adj,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh);

λ_y = Factor expressing the percentage of time when low-cost/must-run power units are on the margin in year *y*

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh);

$EG_{k,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *k* in year *y* (MWh);

$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh);

$EF_{EL,k,y}$ = CO_2 emission factor of power unit *k* in year *y* (tCO_2/MWh);

m = All grid power units serving the grid in year *y* except low-cost/must-run power units;

k = All low-cost/must-run grid power units serving the grid in year *y*;

y = The relevant year as per the data vintage chosen in Step 3.

It is assumed that all the low-cost/must-run plants produce zero net emissions.

$$\frac{\sum_k EG_{k,y} \times EF_{EL,k,y}}{\sum_k EG_{k,y}} = 0 \quad \textbf{(Equation 9)}$$

Determination of $EF_{EL,m,y}$

The emission factor of each power unit *m* was determined as follows:

• **Option A1:** If for a power unit *m* data on fuel consumption and electricity generation is available, the emission factor ($EF_{EL,m,y}$) should be determined as follows:

:

$$EF_{EL,m,y} = \frac{\sum_i FC_{i,m,y} \cdot NCV_{i,y} . EF_{CO2,m,y}}{EG_{m,y}} \quad \textbf{(Equation 10)}$$

Where:

$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO2/MWh)

$FC_{i,m,y}$ = Amount of fossil fuel type *i* consumed by power unit *m* in year *y* (Mass or volume unit)

$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ/mass or volume unit)

$EF_{CO2,i,y}$ = CO_2 emission factor of fossil fuel type *i* in year *y* (tCO_2/GJ)

$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year *y* (MWh)

m = All power units serving the grid in year *y* except low-cost/must-run power units

i = All fossil fuel types combusted in power unit *m* in year *y*

y = The relevant year as per the data vintage chosen in Step 3.

Determination of $EG_{m,y}$

For grid power plants, $EG_{m,y}$ should be determined as per the provisions in the monitoring tables.

The parameter λ_y is defined as follows:

(Equation 11)

$$\lambda_y (\%) = \frac{\text{Number of hours low-cost/must-run sources are on the margin in year y}}{\text{hours per year}}$$

Lambda (λ_y) was calculated according the following steps:

Step (i) Plot a load duration curve. Collect chronological load data (typically in MW) for each hour of the year y, and sort the load data from the highest to the lowest MW level. Plot MW against 8760 hours in the year, in descending order.

Step (ii) Collect power generation data from each power plant / unit. Calculate the total annual generation (in MWh) from low-cost/must-run power plants / units (i.e. $\Sigma_k EG_{k,y}$).

Step (iii) Fill the load duration curve. Plot a horizontal line across the load duration curve such that the area under the curve (MW times hours) equals the total generation (in MWh) from low-cost/must-run power plants / units (i.e. $\Sigma_k EG_{k,y}$).

Step (iv) Determine the "Number of hours for which low-cost/must-run sources are on the margin in year y". First, locate the intersection of the horizontal line plotted in step (iii) and the load duration curve plotted in step (i). The number of hours (out of the total of 8760 hours) to the right of the intersection is the number of hours for which low-cost/must-run sources are on the margin. If the lines do not intersect, then one may conclude that low-cost/must-run sources do not appear on the margin and λ_y is equal to zero.

Net electricity imports must be considered low-cost / must-run plants.

STEP 5. Identify the cohort of power units to be included in the build margin

The sample group of power units m used to calculate the build margin consists of the set of power capacity additions in the electricity system that comprise 20% of the system generation (in MWh) and that have been built most recently, as it comprises the larger annual generation.

The identified power plants are listed in Annex 3.

A power unit is considered to have been built at the date when it started to supply electricity to the grid.

It is important to emphasise that according to the "Tool to calculate the emission factor for an electricity system" version 02, power plants registered as CDM project activities are excluded from the sample group m.

Capacity additions from retrofits of power plants were not included in the calculation of the build margin emission factor.
In terms of vintage of data, the Option 1 was chosen, as it is expected that the BM will not have a wide range of variation during the first crediting period.

STEP 6. Calculate the build margin emission factor

The build margin emissions factor is the generation-weighted average emission factor (tCO_2/MWh) of all power units *m* during the most recent year *y* for which power generation data is available, calculated as follows:

$$EF_{grid,BM,y} = \frac{\sum_m EG_{m,y} \times EF_{EL,m,y}}{\sum_m EG_{m,y}} \quad \textbf{(Equation 12)}$$

Where:

$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year y (tCO_2/MWh);
$EG_{m,y}$ = Net electricity generated and delivered to the grid by power unit *m* in year *y* (MWh);
$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh);
m = Power units included in the build margin;
y = Most recent historical year for which power generation data is available.

The CO_2 emission factor of each power unit *m* ($EF_{EL,m,y}$) was determined as per the guidance in step 4 (a) for the simple OM, using option A1, using for *y* the most recent historical year for which power generation data is available and using for *m* the power units included in the build margin. According to option A, if for a power unit *m* data on fuel consumption and electricity generation is available, the emission factor ($EF_{EL,m,y}$) should be determined as follows:

$$EF_{EL,m,y} = \frac{\sum_{i,j} FC_{i,m,y} \times NCV_{i,y} \times EF_{CO2,i,y}}{\sum_m EG_{m,y}} \quad \textbf{(Equation 13)}$$

Where:

$EF_{EL,m,y}$ = CO_2 emission factor of power unit *m* in year *y* (tCO_2/MWh);
$FC_{i,m,y}$ = Amount of fossil fuel type *i* consumed by power unit *m* in year *y* (Mass or volume unit);
$NCV_{i,y}$ = Net calorific value (energy content) of fossil fuel type *i* in year *y* (GJ / mass or volume unit);
$EF_{CO2,I,y}$ = CO_2 emission factor of fossil fuel type *i* in year y (tCO_2/GJ);
$EG_{m,y}$ = Net quantity of electricity generated and delivered to the grid by power unit *m* in year y (MWh);
m = Power units included in the build margin;
i = All fossil fuel types combusted in power unit *m* in year y.
y = the most recent year for which data is available at the time of submission of the CDM-PDD to the DOE for validation (ex ante option).

STEP 7. Calculate the combined margin emissions factor

The combined margin emission factor is calculated as follows:

$$EF_{grid,CM,y} = w_{OM} * EF_{grid,OM,y} + w_{BM} * EF_{grid,BM,y} \quad \textbf{(Equation 14)}$$

Where:

$EF_{grid,CM,y}$ = Combined margin CO_2 emission factor in year *y* (tCO_2/MWh);
$EF_{grid,OM,y}$ = Operating margin CO_2 emission factor in year *y* (tCO_2/MWh);
$EF_{grid,BM,y}$ = Build margin CO_2 emission factor in year *y* (tCO_2/MWh);
w_{OM} = Weighting of operating margin emission factor (%);
w_{BM} = Weighting of build margin emission factor (%).

B.6.2. Data and parameters that are available at validation:

Data / Parameter:	$EF_{grid,CM,2005-2007}$
Data unit:	tCO_2 / MWh
Description:	Combined margin CO_2 emission factor for the grid connected power generation in year y calculated using the "Tool to calculate the emission factor for an electricity system" version 02.
Source of data used:	Calculated
Value applied:	0.3327
Justification of the choice of data or description of measurement methods and procedures actually applied :	This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period.
Any comment:	Calculated as weighted sum of the OM and BM emission factors, as explained in section B.6.3.

Data / Parameter:	Cap_{BL}
Data unit:	W
Description:	Installed capacity of the hydro power plant before the implementation of the project activity. For new hydro power plants, this value is zero.
Source of data used:	Project site
Value applied:	0
Justification of the choice of data or description of measurement methods and procedures actually applied :	Determine the installed capacity based on recognized standards.
Any comment:	-

Data / Parameter:	A_{BL}
Data unit:	m^2
Description:	Area of the reservoir measured in the surface of the water, before the implementation of the project activity, when the reservoir is full (m^2). For new reservoirs, this value is zero.
Source of data used:	Project site
Value applied:	0
Justification of the choice of data or description of measurement methods	Measured from topographical surveys, maps.

and procedures actually applied :	
Any comment:	-

B.6.3. Ex-ante calculation of emission reductions:

Using equations 7 to 14 above:

$EF_{grid,OM\text{-}adj,2005,2006,2007}$ = 0.5679 tCO_2/MWh (detailed calculation in Annex 3)

$EF_{grid,BM,2007}$ = 0.0975 tCO_2/MWh (detailed calculation in Annex 3)

The default weights are as follows: w_{OM} = 0.5 and w_{BM} = 0.5, for the first crediting period. That gives:

The $EF_{grid,CM,2005,\ 2006,\ 2007}$ = 0.5 x 0.5679 + 0.5 x 0.0975 = 0.3327 tCO_2/MWh

Therefore, for the first crediting period, the emission reductions are calculated for a year *y*, as follows:

ER_y = 0.3327 * $EG_{facility,y}$ (in tCO_2e)

The estimated emissions reductions for a year *y* are:

ER_y = 0.3327 * 198,380 = 66,001 (in tCO_2e)

B.6.4 Summary of the ex-ante estimation of emission reductions:

Year*	Estimation of project activity emission (tonnes of CO_2e)	Estimation of baseline emission (tonnes of CO_2e)	Estimation of leakage (tonnes of CO_2e)	Estimation of overall emission reductions (tonnes of CO_2e)
2011	0	27,500	0	27,500
2012	0	66,001	0	66,001
2013	0	66,001	0	66,001
2014	0	66,001	0	66,001
2015	0	66,001	0	66,001
2016	0	66,001	0	66,001
2017	0	66,001	0	66,001
2018	0	38,500	0	38,500
Total (tonnes of CO_2e)	**0**	**462,006**	**0**	**462,006**

*from 1st August 2011 to 31st July 2018

B.7. Application of the monitoring methodology and description of the monitoring plan:

B.7.1 Data and parameters monitored:

Data / Parameter:	$EG_{facility,y}$

Data unit:	MWh/yr
Description:	Quantity of net electricity generation supplied by the project plant to the grid in year y
Source of data to be used:	El General
Value of data applied for the purpose of calculating expected emission reductions in section B.5	198,380
Description of measurement methods and procedures to be applied:	Measure continuously the accumulated power dispatched to the grid and record hourly. Directly measured during the crediting period. This measurement will follow ICE specification, currently stating that this meter should have 0.2% of precision. Also, the meter will be calibrated every six months. This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period. Both ICE and the project developers are the ones responsible for this measurement.
QA/QC procedures to be applied:	This data will be directly used for calculation of emission reductions. Invoices are used to ensure the consistency and will be used to cross-check.
Any comment:	-

Data / Parameter:	Cap_{PJ}
Data unit:	W
Description:	Installed capacity of the hydro power plant after the implementation of the project activity.
Source of data to be used:	Project site.
Value of data applied for the purpose of calculating expected emission reductions in section B.5	40,000,000
Description of measurement methods and procedures to be applied:	Yearly measurement and recording. Determine the installed capacity based on recognized standards. This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period. This will be done by readings in the generators/turbine nameplates.
QA/QC procedures to be applied:	-
Any comment:	-

Data / Parameter:	A_{PJ}
Data unit:	m^2
Description:	Area of the reservoir measured in the surface of the water, after the implementation of the project activity, when the reservoir is full.
Source of data to be used:	Project site.
Value of data applied	

for the purpose of calculating expected emission reductions in section B.5	46,993
Description of measurement methods and procedures to be applied:	Yearly measurement and recording. Measured from topographical surveys, maps, by internal / third part personnel. This data will be archived electronically and according to internal procedures, until 2 years after the end of the crediting period.
QA/QC procedures to be applied:	-
Any comment:	-

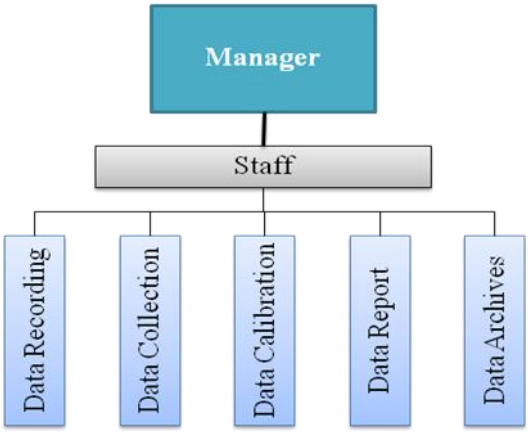
B.7.2. Description of the monitoring plan:

Monitoring tasks must be implemented according to the monitoring plan in order to ensure that the real, measurable and long-term greenhouse gas (GHG) emission reduction for the proposed project is monitored and reported.

1. Management Structure and Responsibilities

Overall responsibility for daily monitoring and reporting lies with the project owner. The manager of the proposed project is responsible for review those reported results/data.

Figure 4. Management structure



- **Data Collection**: The variables that will be monitored in this project activity are:
  1) the electricity supplied by the project activity to the grid will be monitored at the control room (according to the procedures indicated in the section 7.3 of the PPA) and crosschecked with the invoices of electricity commercialized (according to the procedures indicated in section 7.6 of the PPA);
  2) the installed capacity of the hydro power plant after the implementation of the project activity (yearly recording) will be determined based on the characteristics of the equipments installed in the project site;
  3) the area of the reservoir measured by the surface of the water, after the implementation of the project activity, when the reservoir is full (yearly recording) will be measured from topographical surveys, maps.

- **Data Recording**: All the data collected will be kept as a written statement or on a computer database so that it can be easily accessed. The meters shall measure the energy continuously and indicate the accumulated energy in kWh.

- **Data Calibration:** All measurements shall be conducted with calibrated measurement equipment according to the section 7.3 and annex B 3.2 of the PPA. The calibration standard shall be ANSI C12.1, or other standard indicated by Costa Rican law by the time of calibration. There shall be at least two net energy meters installed at the energy delivery point. They shall be solid-state electronic meters with the ability of being monitored remotely (unless ICE and the project owner decide mutually otherwise). The meters shall be maintained and calibrated with a precision of at least 0.2%. The meters shall be sealed by ICE and the project owner and the seals can only be broken at the presence of representatives of both companies.

- **Data Report:** All data recorded will be consolidated on a monthly basis and will be checked for quality control purposes. If there are discrepancies in the data, the source of the variation will be identified, whatever is the main measured value or the control value. The data report will be concluded monthly and will be verified by the Project Developer's Head Office.

- **Data Archives:** The data recording and the data report will be archived, together with this monitoring plan. All data collected as part of monitoring should be archived in electronical/hard copy and kept at least for 2 years after the end of the last crediting period or last issuance of CERs for this project activity.

2. Training and Monitoring Personnel

All people that participate in the monitoring process will be suitably qualified and trained in the operation and maintenance of the plant[15]. They will also receive instructions of the monitoring plan of EGHP.

3. Emission factor calculation

The combined margin emission factor will be fixed for the first crediting period, using ex-ante data for OM and BM as described in section B.6.3.

4. Verification and Monitoring Results

The monitoring report will be prepared by the monitoring personnel. It shall contain the information from data report, the emission factor calculation and the results of the emissions reductions of the project for a certain period.

The verification of the monitoring report is a mandatory process required for all CDM projects. The main objective of the verification is to independently verify that the project has achieved the emission reductions as reported and projected in the PDD.

B.8. Date of completion of the application of the baseline study and monitoring methodology and the name of the responsible person(s)/entity(ies):

The application completion date for the methodology of the project activity study is 24/08/2009.

The person and entity determining the baseline, which is also a project participant, is as follows:
Econergy Brasil Ltda
São Paulo, Brazil
Telephone: +55 (11) 3555-5700

SECTION C. Duration of the project activity / crediting period

C.1. Duration of the project activity:

C.1.1. Starting date of the project activity:

26/01/2004[16].

C.1.2. Expected operational lifetime of the project activity:

17y-0m[17].

[15] The maintenance of the project follows the sections 6.7, 6.8 and 6.9 of the PPA.
[16] Date when Hidroenergía Del General signed an EPC contract.
[17] Term of the PPA.

C.2. Choice of the crediting period and related information:

C.2.1. Renewable crediting period:

C.2.1.1. Starting date of the first crediting period:

01/08/2011 or the date of registration, whichever is later.

C.2.1.2. Length of the first crediting period:

7y-0m.

C.2.2. Fixed crediting period:

C.2.2.1. Starting date:

Left blank on purpose.

C.2.2.2. Length:

Left blank on purpose.

SECTION D. Environmental impacts

D.1. Documentation on the analysis of the environmental impacts, including transboundary impacts:

The Environmental Impact Analysis was developed by Hidroenergía del General S.R.L with the contribution of BEL Ingeniería S.A. and Tratamientos Tecnolóbicos S.A. and sent to the National Environmental Secretary, SETENA (Secretaria Técnica Nacional Ambiental), on 21/10/2000. SETENA attested that the EGHP complied with the environmental viability and was in conformity with the Environmental Organic Law of Costa Rica ("Ley Orgánica del Ambiente" No. 7554, 04/10/1995), on 12/12/2001.

D.2. If environmental impacts are considered significant by the project participants or the host Party, please provide conclusions and all references to support documentation of an environmental impact assessment undertaken in accordance with the procedures as required by the host Party:

The EIA (Environmental Impact Assessment) has established that the environmental impacts that would occur during the construction and operational phases will not be significant.

The environmental impact of the project is minimal and meets, or surpasses, the Costa Rica legal requirements for a project of this nature.

There will be no transboundary impacts resulting from the construction or operation of the EGHP. All the relevant impacts occur within Costa Rican borders and have been mitigated to comply with the environmental requirements for the project's implementation.

SECTION E. Stakeholders' comments

E.1. Brief description how comments by local stakeholders have been invited and compiled:

In accordance with the Costa Rican procedures to obtain the EIA approval, Hidroenergía Del General presented the project to local stakeholders. The benefits of the renewable project to the sustainable development of the country, including the reduction of the greenhouse gases emissions were described in the EIA[18] and presented to the stakeholders. Prisma Comunicaciones was responsible for: developing a newsletter and selecting and inviting local stakeholders to seven meetings. The stakeholders were invited by telephone, by meetings and by letters[19].

Hidroenergía Del General organized various meetings, with residents and local leaders of the communities in the relevant area of influence, such as:

1. Finca 6 (Río Frío de Sarapiquí): Occurred on 27/07/2000 with the participation of community and opinion leaders, local development organizations of Finca 6 communities such as Colonia Villalobos and La Victoria.

2. Puerto Viejo de Sarapiquí: Occurred on 28/07/2000 with the participation of influential leaders such as municipal representatives, ABAS staffs, Puerto Viejo Development Association President, member of the local newspaper Sin Fronteras, a member of Sarapiquí Aquatic Transporters Association (ATAS), the priest of Puerto Viejo, the local delegate of DINADECO, a representative of Fundecor and the Presidential Delegate.

3. Horquetas: Occurred on 01/09/2000 with the participation of the president and vice president of the Development Association, members of the Acueducto Committee, the Huetares school teacher and a Costa Rican Educators Union.

4. Guápiles: Occurred on 03/09/2000 with the participation of the Municipal Council members, the Pococí Mayor and members of the Guápiles development associations. The event was covered by local newspapers.

5. San José: Occurred on 08/09/2000 with the participation of the owners and representatives of the following companies: Claudio Soto e Alex Bolaños from Quabradores Río General S.A.; Carlos Muñoz Méndez from CAMUSA; Ronald Vega Vargas from Constructora Mena S.A. (COMESA).

6. Las Vegas (Horquetas de Sarapiquí): Occurred on 10/09/2000 with the participation of the Development Association President, Río Frio (Finca 6) Development Association President and representatives of Standard Fruit Co.

7. Heredia: Occurred on 17/09/2000 with the participation of members of the municipal council.

[18] EIA Annex 12A: "Consulta a las comunidades".
[19] EIA Annex 12A: "Consulta a las comunidades"; p. 8.

E.2. Summary of the comments received:

Many comments were raised during the meetings, mainly concerning the environmental impacts of the project, operations and technical aspects and contribution of the project to the local communities.

The summary of the comments received are shown below:

- Distrust in SETENA and the negative perceptions of the EIA consultation;
- Interest in the conservation of parks and water sources;
- Interest that the project reward the community by the use of the river and the environmental effects and risks that the project can cause;
- Lack of information on the hydroelectric expansion plans and of national energy demand;
- Negative effects of the transmission line;
- Interest in more details of the project and its ecologic effects such as: flood risk on the arm of Sucio river; necessity of an aqueduct; a possible plan based on the use of the turbine water to an aqueduct; full EIA information unavailability for the community; reservoir security awareness; dike security awareness; critic about the lack of community benefits under the project construction and activity.

E.3. Report on how due account was taken of any comments received:

As the local stakeholder consultation was done in small group interviews, all questions raised were collected and answered promptly. The opinions of the community were collected and considered in the design of the project.

The major changes resulting from this process were:

- A re-routing of the transmission line to avoid more populated areas[20];
- Provide a provision in the discharge for potential future water reuse by communities for water supply[21];
- The location of the water discharge was changed from the old riverbed of the Sucio River to the Chirripo River as a result of concerns from local communities that the Sucio River is already prone to natural flood occurrences, and provide a decrease in water pressure on the existing dam[22];
- Enhancement and enforcement of an existing dam to prevent flooding of communities from natural flood occurrences[23].

As a result of the stakeholder process, Hidroenergía Del General created a Fund (called "Fondo Ecológico Social Educativo") that will be distributed directly to the communities near to the project with the objective to develop social, environmental and educational projects that can improve the quality of life of its population. This fund will be reverted during the 17 years of project operation.

[20] Letter from Hidroenergia Del General to World Bank dated on 20/01/2004.
[21] EIA Annex 12A: "Consulta a las comunidades"; p. 13, 5th paragraph.
[22] Project design nº IG 002.
[23] Letter from Saret de Costa Rica S.A. to Hidroenergia Del General dated on 26/09/2004.

Annex 1

CONTACT INFORMATION ON PARTICIPANTS IN THE PROJECT ACTIVITY

Organization:	Hidroenergía Del General S.R.L
Street/P.O.Box:	2km al Sur de la Catedral de Ciudad Quesada
Building:	
City:	Ciudad Quesada, San Carlos
State/Region:	Alajuela
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Telephone:	(506) 2460-3363
FAX:	(506) 2460-4028
E-Mail:	
URL:	www.hidroplatanar.com
Represented by:	Javier Matamoros Agüero
Title:	General Manager
Salutation:	Mr.
Last name:	Agüero
Middle name:	Matamoros
First name:	Javier
Department:	
Mobile:	
Direct FAX:	(506) 2460-4028
Direct tel:	(506) 2460-3357
Personal e-mail:	javierm@hidroplatanar.com

Annex 2

INFORMATION REGARDING PUBLIC FUNDING

Not applicable.

Annex 3

BASELINE INFORMATION

Table 7. Power plants connected to the Costa Rican SIN in 2006

Name [6]	Starting operation	Efective installed capacity (MW)
1. Hydro Power Plants		
Arenal	1979	157
Corobici-Dengo	1982	174
Sandillal	1993	32
Cachí	1967	103
Garita	1958	40
Menores ICE	Var.	6
Río Macho	1963	134
Ventanas Garita	1988	100
Toro I	1996	27
Toro II	1997	66
Angostura	2000	180
Peñas Blancas	2002	37
Generación Privada	Var.	127
CNFL	Var.	71
ESPH	Var.	19
JASEC	Var.	18
Chocosuela (Coopel.)	1999	28
General (BOT)	2006	39
La Joya (BOT) - CDM	2006	51
Subtotal		1409
2. Thermal power plants		
Barranca	1974	36
S.A.Gas	1973	34
Colima	1956	14
Moin Pistón	1977	26
Moin Gas	1991/1995	131
Moin CNFL	2003	78
Pujo Guápiles	2006	14
Pujol Caldera	2006	10
Subtotal		343
3. Geothermal power plants		
Miravalles I	1994	55
Miravalles II	1998	55
Boca de Pozo	1995	5
Miravalles III (BOT)	2000	26
Miravalles V	2003	18
Subtotal		159
4. Wind Power Plants		
Tejona (CDM)	2002	20
Eólico Privado	1998/2000	46
Subtotal		66
5. Biomass Power Plants		
Río Azul (CDM)	2004	4
Ingenios	2003/2004	7
Subtotal		11
Total NIS		**1988**

Table 8. Thermal power plants applied for the OM emission factor

Thermal Power Plants	Power Generation [1] MWh			Fuel type [3]	Fuel consumed [1] liters		
	2005	2006	2007		2005	2006	2007
COLIMA	16,143	12,708	18,755	92% bunker, 8% diesel	4,625,005	3,733,924	5,387,892
SAN ANTONIO (G)	34,880	52,521	77,306	diesel	14,044,742	20,723,871	30,421,203
MOÍN _2/	97,692	133,109	119,653	diesel	32,812,897	45,206,735	40,878,902
BARRANCA	23,279	35,448	55,471	diesel	9,919,359	15,029,892	23,484,789
MOÍN PISTÓN	16,935	15,534	20,129	95% bunker, 5% diesel	4,164,366	3,824,997	4,899,053
MOÍN GAS	81,933	187,833	294,166	95% bunker, 5% diesel	28,010,885	64,552,739	101,770,582
Pujol Marti	-	96,430	136,765	bunker, diesel	-	20,963,043	29,731,520
Total	**270,863**	**533,583**	**722,245**				

Density	ton/m³ [5]
diesel	0.8513
bunker	0.9690

Thermal Power Plants	EF [2]	NCV [2]	Density [5]	Fuel consumed ton			CO_2 emissions tCO_2		
	tCO_2/TJ	TJ/ton	ton/m³	2005	2006	2007	2005	2006	2007
COLIMA	75.3	0.0399	0.960	4,438	3,583	5,170	13,338	10,768	15,538
SAN ANTONIO (G)	72.6	0.0414	0.851	11,956	17,642	25,898	35,936	53,026	77,839
MOÍN _2/	72.6	0.0414	0.851	27,934	38,484	34,800	83,958	115,671	104,597
BARRANCA	72.6	0.0414	0.851	8,444	12,795	19,993	25,381	38,457	60,091
MOÍN PISTÓN	75.4	0.0399	0.963	4,011	3,684	4,718	12,053	11,071	14,179
MOÍN GAS	75.4	0.0399	0.963	26,978	62,172	98,017	81,072	186,836	294,556
Pujol Marti	72.6	0.0414	0.851	-	17,846	25,310	-	53,638	76,074
Total							**251,738**	**469,466**	**642,873**

Table 9. Group m (set of power plants used in the BM calculation)

Power Plants	Start operation [6]	Type	Generation 2007 [MWh] [4]
Cariblanco	2007	Hydro	140,076
Pujol Marti	2006	Fossil fuel	136,765
Ingenios	2003	Bagasse	12,911
Miravalles V	2003	Geothermal	93,388
Peñas Blancas	2002	Hydro	170,908
Moin CNFL	2003	Fossil fuel	119,653
Angostura	2000	Hydro	874,524
Miravalles III (BOT)	2000	Geothermal	228,719
Chocosuela	1999	Hydro	76,598
Total			**1,853,541**
20% of total generation 2007			**1,783,751**

Table 10. Summarized conclusions of the emission factor calculation

Emission factor for the Costa Rican National Interconnected System			
Baseline	EF_{OM}[tCO_2/MWh]	$1 - \lambda_y$	Generation [MWh]
2005	0.9294	0.6007	8,266,607
2006	0.8798	0.6249	8,690,942
2007	0.8901	0.6675	9,075,881
	$EF_{OM, simple-adjusted}$ 0.5679	$EF_{BM,2007}$ 0.0975	
		Weights_all other projects w_{OM} = 0.50 w_{BM} = 0.50	**EFy [tCO2/MWh]** 0.3327

Table 11. Load duration curve for the Costa Rican interconnected system in 2005

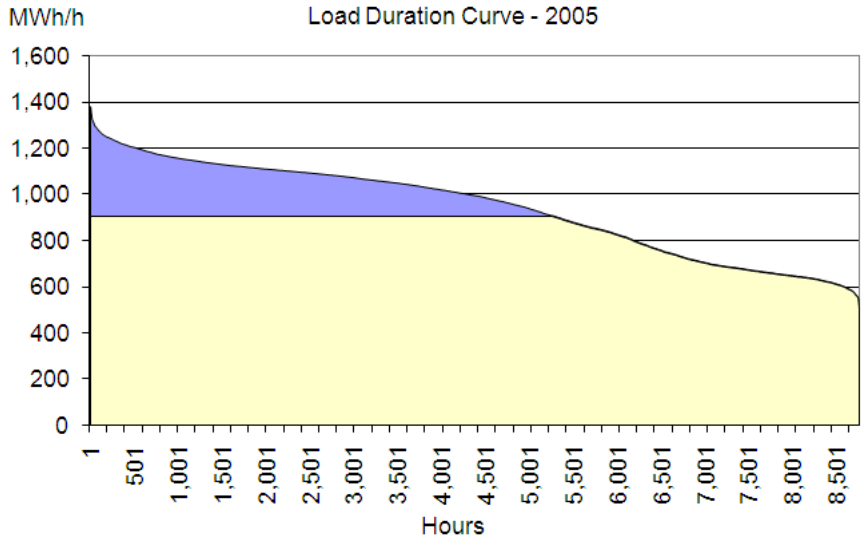


Table 12. Load duration curve for the Costa Rican interconnected system in 2006

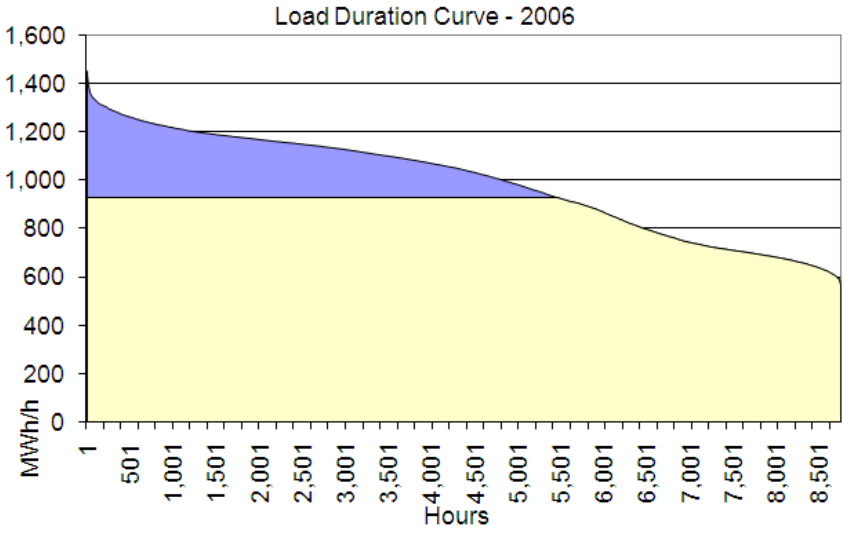
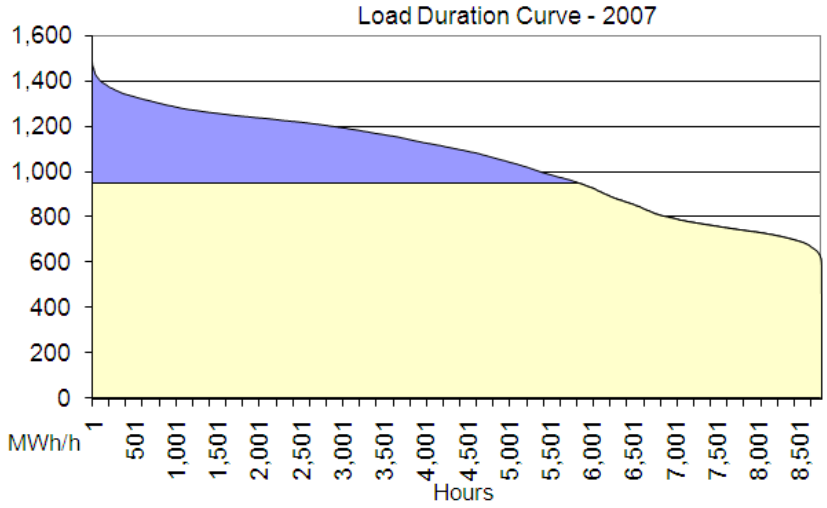


Table 13. Load duration curve for the Costa Rican interconnected system in 2007



Sources:

[1] http://www.aresep.go.cr/cgi-bin/index.fwx?area=09&cmd=servicios&id=9707&sub=1523
[2] IPCC. 2006 Guidelines for National Greenhouse Gas Inventories. Tables 1.2 and 1.4
[3] https://www.grupoice.com/esp/ele/infraest/electric/instalac1f2.htm
[4] http://www.dse.go.cr
[5] RECOPE products manual available at http://www.dse.go.cr
[6] Plan de Expansión de la Generación Eléctrica 2008-2021. P.57. http://www.grupoice.com/esp/ele/planinf/plan_exp.htm

Annex 4

MONITORING INFORMATION

No additional information.